PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

May 5, 2026

VIA ELECTRONIC FILING

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

Re: Advice No. 26-011/Docket UE 470—PacifiCorp's Request for General Rate Revision and Interim Rate Application

PacifiCorp d/b/a Pacific Power (PacifiCorp) submits for filing the following proposed tariff pages associated with PacifiCorp's Tariff P.U.C. OR No. 36, applicable to electric service in the State of Oregon, together with the Executive Summary, Interim Rate Application, and supporting direct testimony and exhibits. The tariffs provided as Exhibit PAC/1003 reflect an effective date of June 4, 2026. Electronic versions of the testimony, exhibits, supporting workpapers, and copies of PacifiCorp's responses to the Standard Data Requests are being uploaded to Huddle.

Sheet	**Schedule**	**Title**
Forty-first Revision of Sheet No. INDEX-3		Table of Contents – Schedules
Sixth Revision of Sheet No. 4-1	Schedule 4	Residential Service Delivery Service
Sixth Revision of Sheet No. 5-1	Schedule 5	Separately Metered Electric Vehicle Service for Residential Consumers Delivery Service
Seventh Revision of Sheet No. 15-1	Schedule 15	Outdoor Area Lighting Service – Delivery Service
Seventh Revision of Sheet No. 23-1	Schedule 23	General Service – Small Nonresidential Delivery Service
Sixth Revision of Sheet No. 28-1	Schedule 28	General Service Large Nonresidential 31KW to 200 KW Delivery Service
Third Revision of Sheet No. 29-1	Schedule 29	General Service Time-Of-Use Large Nonresidential Delivery Service
Sixth Revision of Sheet No. 30-1	Schedule 30	General Service Large Nonresidential 201 KW to 999 KW Delivery Service
Sixth Revision of Sheet No. 41-1	Schedule 41	Agricultural Pumping Service Delivery Service
Sixth Revision of Sheet No. 47-1	Schedule 47	Large General Service Partial Requirements 1,000 KW and Over Delivery Service
Seventh Revision of Sheet No. 48-1	Schedule 48	Large General Service 1,000 KW and Over Delivery Service
Seventh Revision of Sheet No. 51-1	Schedule 51	Street Lighting Service Company – Owned System Delivery Service
Seventh Revision of Sheet No. 53-1	Schedule 53	Street Lighting Service Consumer – Owned System Delivery Service

Sheet	**Schedule**	**Title**
Seventh Revision of Sheet No. 54-1	Schedule 54	Recreational Field Lighting – Restricted Delivery Service
Sixth Revision of Sheet No. 76R-1	Schedule 76R	Large General Service – Partial Requirements Service Economic Replacement Power Rider Delivery Service
Original Sheet No. 80	Schedule 80	Interim Rate Adjustment
Original Sheet No. 81	Schedule 81	Service Area Transfer Adjustment
Thirty-seventh Revision of Sheet No. 90-1	Schedule 90	Summary of Effective Rate Adjustments
Fourth Revision of Sheet No. 96-1	Schedule 96	Property Sales Balancing Account Adjustment
Fourth Revision of Sheet No. 190-1	Schedule 190	Wildfire Mitigation Plan Cost Recovery Adjustment
Fourth Revision of Sheet No. 192-1	Schedule 192	Deferred Accounting Adjustment
Tenth Revision of Sheet No. 200-1	Schedule 200	Base Supply Service
Tenth Revision of Sheet No. 200-2	Schedule 200	Base Supply Service
Tenth Revision of Sheet No. 200-3	Schedule 200	Base Supply Service
Thirteenth Revision of Sheet No. 202-1	Schedule 202	Renewable Adjustment Clause Supply Service Adjustment
Eleventh Revision of Sheet No. 203-1	Schedule 203	Renewable Resource Deferral Supply Service Adjustment
Sixth Revision of Sheet No. 299	Schedule 299	Rate Mitigation Adjustment
Fifth Revision of Sheet No. 300-3	Schedule 300	Charges as Defined by the Rules and Regulations
Sixth Revision of Sheet No. 723-1	Schedule 723	General Service – Small Nonresidential Direct Access Delivery Service
Sixth Revision of Sheet No. 728-1	Schedule 728	General Service Large Nonresidential 31 KW to 200 KW Direct Access Delivery Service
Sixth Revision of Sheet No. 730-1	Schedule 730	General Service Large Nonresidential 201 KW to 999 KW Direct Access Delivery Service
Sixth Revision of Sheet No.741-1	Schedule 741	Agricultural Pumping Service Direct Access Delivery Service
Sixth Revision of Sheet No. 747-1	Schedule 747	Large General Service Partial Requirements 1,000 KW and Over Direct Access Delivery Service
Seventh Revision of Sheet No. 748-1	Schedule 748	Large General Service 1,000 KW and Over Direct Access Delivery Service
Seventh Revision of Sheet No. 751-1	Schedule 751	Street Lighting Service Company-Owned System Direct Access Delivery Service
Seventh Revision of Sheet No. 753-1	Schedule 753	Street Lighting Service Consumer-Owned System Direct Access Delivery Service

Sheet	Schedule	Title
Seventh Revision of Sheet No. 754	Schedule 754	Recreational Field Lighting–Restricted Direct Access Delivery Service
Sixth Revision of Sheet No. 776R-1	Schedule 776R	Large General Service-Partial Requirements Service-Economic Replacement Service Rider Direct Access Delivery Service
Fourth Revision of Sheet No. 848-1	Schedule 848	Large General Service 1,000 KW and Over Direct Access Delivery Service – Distribution Only

Confidential material in support of the filing has been provided to parties who have signed General Protective Order No. 23-132 for this docket.

Please address all communications related to this filing to:

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Please direct informal correspondence and questions regarding this filing to Amira Thompson, State Regulatory Affairs Manager, at (503) 260-4420.

Sincerely,

Robert Meredith
Director, Regulation

Enclosures

Cc: Service List UE 433
Service List UE 470

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 470

In the Matter of PACIFICORP d/b/a PACIFIC POWER Request for a General Rate Revision.	**EXECUTIVE SUMMARY**

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp) respectfully requests the Public Utility Commission of Oregon (Commission) revise PacifiCorp's schedules of rates and charges for Oregon electric services under ORS 757.205 and 757.220.

PacifiCorp is requesting an overall increase in rates of approximately $170.7 million or 8.6 percent. To address near-term financial needs, PacifiCorp requests approval of an interim increase in rates of approximately $55.1 million or 2.8 percent, effective June 4, 2026. If interim rates are approved, PacifiCorp requests that the remaining rate increase take effect on July 15, 2027. If interim rates are not approved, PacifiCorp requests that the entirety of the proposed rate increase take effect on April 5, 2027. PacifiCorp's requested rate increase is mitigated by the end of the 2022 Power Cost Adjustment Mechanism (PCAM) amortization which is a $65.3 million or 3.2 percent decrease. PacifiCorp has also filed the 2027 TAM projecting a $55.7 million or 2.8 percent decrease,[1] and expects a $95.7 million or 4.7 percent decrease in 2027 related to the end of the amortization of the 2021, 2023 and 2024 PCAMs. Taken together, the impact of the rate case net of the anticipated TAM and PCAM changes is an overall average 2.1 percent decrease.

[1] *In the Matter of PacifiCorp d/b/a Pacific Power's 2027 Transition Adjustment Mechanism,* Docket No. UE 469, PAC/300, Ridenour at 4.

This general rate revision is necessary because PacifiCorp is currently forecasted to earn a normalized return on equity (ROE) in Oregon of 7.2 percent under current rates, which is less than PacifiCorp's currently authorized ROE of 9.5 percent. PacifiCorp's proposed rates would produce revenues that are necessary to sustain a stable, reliable, and low-cost power supply, while also preserving PacifiCorp's ability to attract capital for future investments.

PacifiCorp is an electric company and public utility in Oregon within the meaning of ORS 757.005, and is subject to the Commission's jurisdiction regarding PacifiCorp's prices and terms of electric service for Oregon retail customers. PacifiCorp provides electric service to approximately 667,000 retail customers in Oregon, and approximately 2.1 million total retail customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's principal place of business is Portland, Oregon. This executive summary and the attached Exhibit A are filed in compliance with OAR 860-022-0019.

PacifiCorp requests that communications regarding this filing be addressed to:

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Please direct informal correspondence and questions regarding this filing to Amira Thompson, State Regulatory Affairs Manager, at (503) 260-4420.

II. CASE SUMMARY

PacifiCorp is requesting an overall increase in rates of approximately $170.7 million[2] for rates effective April 5, 2027,[3] and if approved, would result in a $1,393.6 million non-net power cost revenue requirement, based on the continued use of the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol). This revenue requirement is based on a historical base period of 12 months that ended June 2025, and normalizing and pro forma adjustments to calculate a calendar year 2027 future test period (with the exception of capital additions that are based on March 31, 2026 balances).

PacifiCorp is also requesting an interim increase in rates of approximately $55.1 million for rates effective June 4, 2026, as addressed in a separate and concurrently

[2] The total increase includes approximately $9.0 million in adjustments outside of base revenue requirement.
[3] The proposed April 5, 2027, rate effective date reflects the new 10-month suspension period in ORS 757.215(1), in addition to the 30-day effective date.

filed Application. If interim rates are approved, PacifiCorp proposes that the final rate increase would be deferred from April 5, 2027, to July 15, 2027.

The following briefly summarizes PacifiCorp's weighted average cost of capital (WACC), cost drivers, and rate design.

A. Weighted Average Cost of Capital

PacifiCorp is requesting an overall WACC of 7.56 percent. This is based on an increased ROE to 9.70 percent from the currently authorized 9.50 percent, and a cost of long-term debt of 5.41 percent. PacifiCorp also proposes a hypothetical capital structure that includes 50.00 percent common stock, and 50.00 percent long-term debt.

This proposed WACC is necessary to maintain the financial integrity of PacifiCorp, while ensuring its ability to provide safe, efficient, and reliable service to its Oregon customers with minimal rate impacts.

B. Cost Drivers

This rate request includes several cost drivers, including new capital additions and increased operating and maintenance expenses.

i. Capital Additions

PacifiCorp continues to make new investments in its system that are required to provide safe, adequate, and reliable service to customers and to comply with regulatory mandates. Incremental additions included in this case include investments in all facets of PacifiCorp's system—including transmission, generation, distribution, and customer support assets—to bolster reliability and improve power delivery and customer services. This includes the Willamette River Crossing project, completed in 2026.

ii. Operating and Maintenance Costs

PacifiCorp is requesting recovery of increased operating and maintenance costs for several categories of costs. These include increases to insurance premiums that have been caused by increased wildfire liability risks in the region generally, and for PacifiCorp specifically.

C. Treatment of Washington Sale

On February 17, 2026, the company announced that it had entered into an agreement with Portland General Electric Company (PGE) to sell certain generation and transmission assets located in Washington and the entirety of its Washington distribution system (the Service Area Transfer). PacifiCorp filed applications for approval of the Service Area Transfer in March and April 2026, and the company currently expects the transaction to be approved and close by April 2027. In Oregon, the approval filing has been docketed as UP 441.

The sale of the Washington service area and related assets will impact the Oregon-allocated revenue requirement by removing certain assets and associated costs from rates and revising the dynamic allocation factors used to allocate total-company costs among the states. The estimated incremental annual revenue requirement impact of non-NPC updates due to the Service Area Transfer is an increase of approximately $17.3 million, which will be largely offset by a proposed estimated annual customer rate credit of $14.3 million. The company proposes implementing the revenue requirement increase through a new base adjustment and passing back the rate credit through Schedule 96, Oregon's property sales balancing account adjustment over a three-year period.

The company proposes a separate rate change to reflect the non-NPC costs and benefits of the Service Area Transfer. If approval of the Service Area Transfer occurs before

the rate effective date in this case (either April 5, 2027 (without interim rates) or July 15, 2027 (with interim rates)), then rates put into effect in this case will include the full incremental annual revenue requirement effect of the Service Area Transfer upon the rate effective date. If this occurs, the requested net non-NPC rate increase would be $173.7 million. However, if approval of the Service Area Transfer does not occur before rates become effective in this case, then the incremental impact will be implemented as a second-step rate change to align with the final closing of the Service Area Transfer.

D. Rate Design

PacifiCorp is proposing a rate spread that is consistent with the cost-of-service study and utilizes the rate mitigation adjustment to ensure no customer rate class will see a net increase greater than 10.8 percent. PacifiCorp proposes an average 8.6 percent increase to current rates. PacifiCorp is proposing to increase the residential basic charge from its current level of $14 per month to $17 for single-family customers and from $8 to $9 for multi-family customers to better reflect the fixed costs of serving residential customers. The company is not proposing any changes to the underlying rate structures for non-residential customers.

III. TESTIMONY SUMMARY

PacifiCorp's general rate revision is supported by the following testimony and exhibits of 10 PacifiCorp witnesses or third-party expert consultants:

- **Ryan L. Flynn,** President of Pacific Power, provides an overview of PacifiCorp, its Oregon service area, and the strategies PacifiCorp is pursuing to provide Oregon customers with safe, reliable, and affordable energy. He introduces the company's request for interim rates. He also explains the escalating wildfire risk and financial pressure that PacifiCorp has faced since its last rate case, the steps PacifiCorp is

taking to address those risks, and introduces PacifiCorp witnesses that provide direct testimony in support of PacifiCorp's rate request.

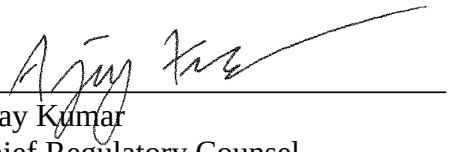
- **Rick T. Link**, Senior Vice President, Regulation and Planning, describes PacifiCorp's request in this proceeding and summarizes the company's regulatory policies. He also discusses PacifiCorp's interim rates request and its request to recover a full return on the Gateway South transmission line.
- **M. Ryan Weems**, Chief Financial Officer and Treasurer, addresses PacifiCorp's overall cost of capital recommendation for PacifiCorp, including a capital structure to maximize value and minimize risk and the current cost of debt. He also explains why the company is seeking interim rates.
- **Ann E. Bulkley**, Principal at The Brattle Group, provides a comparison of PacifiCorp's business and financial risk compared to peer utilities, recommends a cost of equity, and provides supporting analyses.
- **Jacqueline T. Wetzsteon**, Environmental Program Manager, and **Bryce K. Foster**, Director of Project Delivery, discuss the Willamette River Crossing project.
- **Jayson D. Branch,** Senior Vice President of Power Supply, supports PacifiCorp's coal inventory levels and strategy.
- **Travis R. Walker**, Senior Business Specialist, supports PacifiCorp's load forecast for the test period.
- **Shelley E. McCoy**, Director of Revenue Requirement, summarizes the overall test year revenue requirement, pro forma adjustments, and the rate base calculation methodology.

- **Kenneth Lee Elder, Jr.**, Director of Pricing and Tariff Policy, provides PacifiCorp's cost of service study.
- **Judith M. Ridenour**, Pricing and Cost of Service Specialist, provides PacifiCorp's rate spread and design and discusses how the proposed tariff changes, including the interim rates request, recover the proposed revenue requirement to achieve fair, just, and reasonable prices for customers.

IV. CONCLUSION

PacifiCorp respectfully requests the Commission approve PacifiCorp's proposed general rate revisions and tariff amendments.

Respectfully submitted May 5, 2026.



Ajay Kumar
Chief Regulatory Counsel

PacifiCorp d/b/a Pacific Power

EXHIBIT A

Exhibit A
Summary of Requested Electric General Rate Increase
Oregon Allocated
Filed May 5, 2026

(A)	Total net revenues collected under proposed rates:	$2,147,290,000
(B)	**Base**[1]	
	Revenue change requested:	
	Total:	$178,960,000
	Net of credits from federal agencies:	$178,960,000
	Net[2]	
	Revenue change requested:	
	Total:	$173,647,000
	Net of credits from federal agencies:	$173,647,000
(C)	**Base**[1]	
	Percentage change in revenues requested:	
	Total %:	10.0%
	Net of credits from federal agencies:	10.0%
	Net[2]	
	Percentage change in revenues requested:	
	Total %:	8.8%
	Net of credits from federal agencies:	8.8%

(D)	Test period:	Calendar year 2027
(E)	Requested return on capital:	7.56%
	Requested return on equity:	9.70%
(F)	Rate base proposed in filing:	$6,085,803,981
(G)	Results of operation:	
	Utility operating income, before proposed change:	$382,522,225
	Utility operating income, after proposed change:	$459,782,491

(H)	Effect of rate change on each customer class:	Base Change[1]	Net Change[2]
	• Residential:	13.9%	11.3%
	• Small General Service (Schedule 23):	16.4%	11.5%
	• General Service 31-200 kW (Schedule 28):	13.8%	8.6%
	• General Service 201-999 kW (Schedule 30):	6.2%	5.0%
	• Large General Service >= 1,000 kW (Schedule 48):	0.4%	4.7%
	• Agriculture Pumping Service (Schedule 41):	13.1%	11.7%
	• Lighting	2.1%	3.8%
	• Total	10.0%	8.8%

(I)	Information Required by Utility Staff General Rate Case Data Request Form A:	Provided under separate cover

[1] Base change includes $17.3 million for the proposed Service Area Transfer base revenue requirement adjustment as discussed in the application and testimony.

[2] Net Change reflects the net impact to customers on April 5, 2027, of the proposed price change including the base change plus $1.4 million for the true-up of the Wildfire Mitigation Plan automatic adjustment clause, $1.6 million for deferred increased insurance premium costs, $6.0 million for additional Renewable Resource Deferral costs and a reduction of $14.3 million for the Washington Service Area Transfer Property Sales Balancing Account adjustment as discussed in the application and testimony.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 470

In the Matter of PACIFICORP d/b/a PACIFIC POWER Request for a General Rate Revision.	APPLICATION FOR APPROVAL OF INTERIM RATES

I. INTRODUCTION

In accordance with ORS 757.215(5), OAR 860-022-0025(2), and OAR 860-001-0400, PacifiCorp d/b/a Pacific Power respectfully requests that the Public Utility Commission of Oregon (Commission) authorize an interim rate increase of $55.1 million effective June 4, 2026, thirty days from this filing.

PacifiCorp does not make this request lightly and recognizes that customers continue to face broad affordability challenges and headwinds associated with economic development, housing, and education. Although rare, interim rates are reasonable in this case and are an important step to ensure that PacifiCorp can continue to be a partner in supporting Oregon and its citizens. First, PacifiCorp is currently facing severe financial distress that has decreased the company's credit ratings and constrained its access to capital. Interim rate relief will mitigate the risk of further downgrades, which would strain PacifiCorp's ability to deliver reliable service and maintain reasonable rates by driving up borrowing costs and further limiting access to capital. Second, interim rate relief will also provide PacifiCorp much-needed short-term liquidity, allowing the company to continue to support day-to-day operations and proactively advance Oregon's policy goals during the pendency of this general rate case. Third, PacifiCorp has

designed the interim rates to minimize their impact by both phasing in and delaying the effective date of the 2027 general rate increase.

II. DESCRIPTION OF INTERIM RATE PROPOSAL

PacifiCorp proposes a two-step rate change in this general rate case: (1) an interim rate increase effective June 4, 2026, thirty days from this filing, to shore up PacifiCorp's near-term financial position, and (2) a final rate increase effective July 15, 2027. While PacifiCorp's general rate case filing proposes a final rate increase effective April 5, 2027, immediately after the conclusion of the statutory suspension period, approval of interim rates would allow PacifiCorp to delay the final rate increase to July 15, 2027. The proposed interim rates reflect a revenue requirement increase of approximately $55.1 million, or about 2.8 percent. The proposed interim rates represent approximately 32 percent of the overall revenue requirement increase of $170.7 million, or 8.6 percent, included in the general rate case. Consistent with ORS 757.215(5), the interim rates would be subject to refund.

PacifiCorp's proposed interim rates are conservative because the revenue requirement is less than costs that have already been incurred—meaning that the costs are known and measurable and reflect investments that are currently used, useful, and serving Oregon customers. PacifiCorp's interim revenue requirement reflects costs necessary to serve Oregon customers while this case is pending and simultaneously minimizes the impact to customers.

PacifiCorp designed the proposed interim rates to further minimize the impact to customers by limiting the rate increase so that it is effectively offset by the rate change that occurred on May 1, 2026, when the 2022 Power Cost Adjustment Mechanism (PCAM) surcharge ended. Indeed, the proposed interim rates reflect a net decrease on average for all

customers and a zero net price change for typical residential customers.[1] By effectively offsetting the 2022 PCAM revenue requirement, PacifiCorp's cash flows will continue, while customers will experience a minimal rate change, due exclusively to the different rate spread applicable to the PCAM amortization and the interim increase.

Additionally, in early 2027, the customer impact of the proposed interim rates will likely be further mitigated by the 2027 Transition Adjustment Mechanism (TAM) and the end of the amortizations of the 2021, 2023, and 2024 PCAM balances, effective January 1, 2027, and April 1, 2027, respectively. With these adjustments, PacifiCorp anticipates that, in early 2027, rates would be approximately 7.9 percent less than they were as of the end of April, on average.

PacifiCorp's proposed interim rates will not unduly or unreasonably prejudice any customer class because costs will be spread uniformly to all customers based on their share of present revenues derived from demand charges and from energy charges. PacifiCorp will implement this interim rate increase through a percentage surcharge applied to customer bills, which will be canceled when the general rate increase takes effect.

III. LEGAL STANDARD

ORS 757.215(5) authorizes the Commission to grant an interim rate in a suspension order.[2] The Commission has explained that interim rates are appropriate when a utility faces "severe financial stress" such that "its ability to serve the public at reasonable rates will be jeopardized."[3] Although interim rates are rare, the Commission has previously granted interim

[1] The average residential customer living in a single-family dwelling using 900 kilowatt-hours per month will see a bill increase of $4.01 per month from the interim increase and a bill decrease of $4.03 per month from the 2022 PCAM.

[2] ORS 757.215(5); *see also In the Matter of Long Butte Water System, Inc., Application for Authorization to Increase the Company's Total Annual Revenues by $97,354,00 or 78 Percent*, Docket No. UW 110, Order No. 05-1141 at 2 (Oct. 25, 2005) ("ORS 757.215(5) contemplates that a utility will request interim rate relief when it files its permanent rate increase application and any interim relief will be authorized in a suspension order.").

[3] *In re Portland Gen. Elec. Co.*, Docket Nos. UE 47 & 48, Order No. 87-1017 (Sep. 30, 1987) ("Where the utility can show a compelling need for immediate rate relief, interim rate increases will be considered. However, the utility

rates for PacifiCorp following the 2001 energy crisis[4] and after the termination of construction of a wind and a nuclear facility.[5] The Commission has also approved interim rates for water utilities facing severe financial distress.[6] Moreover, the Commission has cited interim rate relief as a tool to "help incent utility investments that further the interests of ratepayers and the public."[7] After completing the general rate case hearing and final decision, the Commission may order the utility to refund any portion of an interim rate increase that it finds not justified, including interest.[8]

IV. ARGUMENT

PacifiCorp is facing acute financial pressure that jeopardizes its ability to serve Oregon customers at reasonable rates and advance Oregon's energy policies. PacifiCorp's proposed interim rates will improve its financial health by increasing cash flows and mitigating the risk of further credit ratings downgrades and day-to-day operations. Further downgrades will drive up borrowing costs, increasing PacifiCorp's cost of capital, and risks access to capital at a time when it is increasingly vital to access the capital market to support day-to-day operations and support critical investments in PacifiCorp's system, including wildfire mitigation investments.

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should show severe financial stress or some other such reason to gain approval of a request for interim rates.").

[4] *In the Matter of the Application of PacifiCorp for an Accounting Order Regarding Excess Net Power Costs (UM 995); In the Matter of PacifiCorp's Application for Partial Amortization of Its Request to Defer Excess Net Power Costs and Approval of Its Request to Implement an Amortization in Rates of Deferred Excess Net Power Costs (UE 121); Indus. Customers of Nw. Utils. & Citizens' Util. Bd. vs. PacifiCorp (UC 578)*, Docket Nos. UM 995, UE 121, & UC 578, Order No. 01-186 at 1 (Feb. 21, 2001) (approving interim rates following the 2001 energy crisis).

[5] *In the Matter of Revised Tariff Schedules for Electric Service in the State of Oregon, filed by Pac. Power & Light Co.*, Docket No. UF 3779, Order No. 82-252 (Apr. 8, 1982) (granting interim rates following the default of the Washington Public Power Supply System).

[6] *See, e.g.*, *In the Matter of Alsea Properties, Inc., Westwood Water System, Request for a General Rate Revision and Interim Rate Increase*, Docket No. UW 159, Order No. 13-488 (Dec. 20, 2013); *In the Matter of Willamette Water Co., Request for a General Rate Increase and Request for Interim Rate Relief*, Docket No. UW 125, Order No. 08-102 (Jan. 28, 2008); *In the Matter of Northridge Water Co., Inc., Request for a General Rate Increase and Request for Interim Relief*, Docket No. UW 141, Order No. 10-166 (Apr. 27, 2010); *In the Matter of Tierra Del Mar Water Co., Request for a General Rate Revision*, Docket No. UW 210, Order No. 26-148 (Apr. 29, 2026).

[7] *In the Matter of Pub. Util. Comm'n of Or., Investigation of the Scope of the Commission's Authority to Defer Capital Costs*, Docket No. UM 1909, Order No. 19-053 at 5 (Feb. 19, 2019).

[8] ORS 757.215(5); ORS 757.215(6).

PacifiCorp's proposed interim rates are also designed to mitigate customer rate impacts because the proposed increase is largely offset by a PCAM rate reduction and will enable the company to delay its proposed permanent rate increase by more than three months.

A. Interim rates will help mitigate PacifiCorp's continued poor financial health that detrimentally impacts customers and jeopardizes its ability to provide service at reasonable rates.

PacifiCorp is currently facing the exact "severe financial stress" that makes interim rates "appropriate."[9] As detailed thoroughly in the testimonies of company witnesses Ryan L. Flynn and M. Ryan Weems, PacifiCorp has been under extraordinary financial pressure recently, stemming primarily from adverse wildfire liability issues, weakened financial metrics, and regulatory pressures. Such financial instability harms the company and its customers. Indeed, PacifiCorp's credit ratings have continually declined over the past three years to the point where PacifiCorp is currently just one step above junk status. Notably, poor credit ratings directly increase borrowing costs, which in turn raises customer rates.

Not only does PacifiCorp's poor financial health increase borrowing costs, but it also limits PacifiCorp's access to capital. To illustrate, as a result of numerous recent changes to PacifiCorp's credit rating outlook by S&P, PacifiCorp temporarily lost access to the junior subordinated debt market in March 2026. Additionally, one more credit downgrade would put PacifiCorp below investment grade, which would disrupt its ability to attract capital by materially shrinking the pool of investors that PacifiCorp can access; many institutional investors are not permitted to purchase non-investment grade or junk securities. PacifiCorp remains in a precarious position.

[9] Order No. 87-1017.

Regulatory support is a key factor for credit rating agencies and investors, and approving interim rates will enable PacifiCorp to increase its near-term cash flows to support its current credit rating and mitigate the risk of further downgrades. PacifiCorp will be facing additional pressure on the company's weakened credit metrics as contracts for the 2025 Oregon Situs Request for proposals are executed. Interim rates will help mitigate these credit metric pressures.

Further, PacifiCorp is making "every effort" to restore its financial health and is not relying solely on interim rates, consistent with the Commission's prior guidance when approving interim rates for PacifiCorp.[10] For instance, PacifiCorp has re-prioritized and reduced its planned capital expenditures over the 2024 through 2026 period.

PacifiCorp is actively engaged in several financial stabilization efforts in addition to interim rate relief, including suspending all dividends beginning in 2023 through at least the next several years, which will improve retained earnings and make capital available to ongoing capital requirements, and entering a long-term sale-leaseback transaction for the company's share of the Boardman-to-Hemingway transmission line, which will provide a much needed capital infusion. PacifiCorp is also generating cash and reducing risk by selling its entire Washington service area and parts of its Oregon service territory.

Ultimately, PacifiCorp recognizes that its requested interim rate increase comes at a time when customers are facing increasing prices for all necessities, but the requested modest interim relief will improve PacifiCorp's financial health, in turn benefiting customers by reducing the immediate and future borrowing costs related to providing safe and adequate service at reasonable rates.

[10] Order No. 82-606.

B. Interim rates will provide PacifiCorp short-term liquidity, allowing the company to support operations and proactively advance Oregon energy policies.

The utility industry is capital intensive and regulatory lag can put pressure on cash flows, straining credit metrics and decreasing the ability to make necessary investments. Interim rates help provide PacifiCorp the short-term liquidity to better invest in necessary resources and infrastructure in Oregon. Even factoring in PacifiCorp's reduction in forecast capital expenditures, the company still forecasts $7.9 billion in capital investments over the 2026 through 2028 timeframe, including approximately $1.5 billion in wildfire mitigation efforts. Absent interim rate relief, PacifiCorp will not see incremental revenues from a rate increase until April 5, 2027, yet in 2026 alone, PacifiCorp forecasts approximately $2.9 billion in capital expenditures. Interim rates will strengthen PacifiCorp's cash flows to assist in these capital investments and reduce the need to issue additional debt at a high cost given PacifiCorp's current credit rating. The incremental revenues from interim rates will also support the company's day-to-day operations. Additionally, the revenue generated from interim rates will help mitigate credit metric pressures associated with resource procurement activities coming out of the 2025 Oregon Situs Request for Proposals, which is expected to include contracts for new resources consistent with Oregon's energy policy.

In sum, PacifiCorp must make significant, near-term investments in Oregon to advance Oregon policy objectives and continue providing safe and adequate service at reasonable prices, requiring the short-term liquidity that interim rates bring.

C. PacifiCorp's interim rate proposal is designed to mitigate customer impact.

If PacifiCorp's proposed interim rates are adopted, overall customer rates would be nearly flat in 2026 and are expected to decrease in early 2027. The proposed interim revenue requirement increase is essentially offset by the revenue requirement decrease that took effect on

May 1, 2026, with the end of the 2022 PCAM surcharge. Therefore, interim rates will not change residential rates for the typical residential customer. Further, even with the proposed interim rates increase, PacifiCorp expects that rates in early 2027 would be approximately 7.9 percent less than they were at the end of April 2026, as a result of the decrease from the end of the 2022 PCAM on May 1, 2026, the filed 2027 TAM and the decrease from the end of the amortization of the 2021, 2023, and 2024 PCAM balances, effective January 1, 2027, and April 1, 2027.

Additionally, if interim rates are approved, PacifiCorp proposes that the general rate increase take effect on July 15, 2027, more than three months after the proposed April 5, 2027, effective date if interim rates are not approved. Moreover, the general rate increase that would occur in July 2027 would be a smaller increase if interim rates are in effect than if no interim increase occurs. Specifically, if interim rates are approved, the general rate increase would be 5.7 percent instead of 8.6 percent. By phasing in and delaying some of the rate increase, interim rates would reduce volatility to the benefit of customers and soften customer bill impacts.

V. DESCRIPTION OF SUPPORTING TESTIMONY

PacifiCorp's request for interim rates is supported by testimony from the following witnesses:

- In Exhibit PAC/100, **Ryan L. Flynn**, President of Pacific Power, explains why interim rate relief is appropriate and necessary given PacifiCorp's financial status.
- In Exhibit PAC/200, **Rick T. Link**, Senior Vice President of Regulation and Planning, provides an overview of the interim rate request and explains the impact to customers and how PacifiCorp moderated its request to reduce the impact.
- In Exhibit PAC/300, **M. Ryan Weems**, Senior Vice President, Chief Financial Officer and Treasurer, discusses PacifiCorp's current financial situation, explains how PacifiCorp's financial health impacts customers, details the actions PacifiCorp has taken to improve its financial position, and demonstrates how interim rates will relieve financial pressure and support the company's financial metrics.

- In Exhibit PAC/800, **Shelley E. McCoy**, Director of Revenue Requirement, explains how the company determined and calculated the level of proposed interim rates.
- In Exhibit PAC/1000, **Judith M. Ridenour**, Specialist, Pricing and Cost of Service, discusses and presents the interim rate tariffs, explains that interim rates will not materially change the revenue relationships among customer classes or between the revenues derived from demand charges and from energy charges, and presents the rate impacts of the interim rate request.

VI. CONCLUSION

In accordance with ORS 757.215(5), PacifiCorp respectfully requests that the Commission authorize interim rate relief and approve an interim rate increase of $55.1 million, effective June 4, 2026, thirty days after this filing, to alleviate PacifiCorp's severe financial stress that harms both the company and its customers and impedes PacifiCorp's ability to invest in Oregon.

Respectfully submitted May 5, 2026.

Ajay Kumar
Chief Regulatory Counsel

PacifiCorp d/b/a Pacific Power

ACRONYM LIST

Witness	Acronym	Definition
McCoy	13 MA	Thirteen-month average
Link	2020 Protocol	2020 PacifiCorp Inter-Jurisdictional Allocation Protocol
Bulkley	AAC	Automatic Adjustment Clause
McCoy	ADIT	Accumulated Deferred Income Tax
McCoy	AFUDC	Allowance for Funds Used During Construction
McCoy	Base Period	Historical period of the 12 months ended in June 2025
Branch	Base Year	2025 General Rate Case
Weems	BHE	Berkshire Hathaway Energy
McCoy	BOSR	Body of State Regulators
Bulkley	BYRP or Risk Premium	Bond Yield Risk Premium
Bulkley	CAPM	Capital Asset Pricing Model
Foster-Wetzsteon	CERCLA	Comprehensive Environmental Response Compensation and Liability Act
Weems	CFO Pre-WC/Debt	Pre-working capital cash flow divided by debt
Foster-Wetzsteon	CGL	Comprehensive General Liability
Weems	Commission	Oregon Public Utility Commission
Branch	CSA	Coal Supply Agreement
Bulkley	DCF	Discounted Cash Flow
Link	DEQ	Oregon Department of Environmental Quality
Bulkley	ECAPM	Empirical Capital Asset Pricing Model
McCoy	ECD	Embedded Cost Differential
Link	EDAM	Extended Day Ahead Market
McCoy	EDIT	Excess Deferred Income Tax
Bulkley	EIA	Energy Information Administration
Foster-Wetzsteon	EPA	U.S. Environmental Protection Agency
McCoy	EPIS	Electric Plant in Service
Bulkley	EPS	Earnings Per Share
Walker	EV	Electric Vehicle
Elder	Facilities	Large Energy Use Facilities
McCoy	FAIR	Fairness & Affordability in Residential
Bulkley	FEMA	Federal Emergency Management Agency
Weems	FERC	Federal Energy Regulatory Commission
Weems	FFO	Funds From Operations
Weems	FFO/Debt	Funds from operations divided by debt
Bulkley	FOMC	Federal Open Market Committee
Bulkley	GDP	Gross Domestic Product
McCoy	GRC	General Rate Case
Link	GW	Gigawatts
Link	HB	House Bill
Foster-Wetzsteon	HDD	Horizontal Directional Drilling
Bulkley	IOUs	Investor Owned Utilites
Link	IRP	Integrated Resource Plan
Elder	kW	Kilowatt
Walker	kWh	Kilowatt-hour
Walker	LED	Light-emitting diode
McCoy	M&S	Material and supplies
Walker	MAPE	Mean Absolute Percentage Error
Weems	Moody's	Moody's Investors Service
Elder	MW	Megawatt
McCoy	MWh	Megawatt-hour
McCoy	NEO	Named Executive Officers
McCoy	Non-T&D	Non-transmission and distribution
Flynn	NPC	Net Power Cost
Foster-Wetzsteon	NPL	Federal Superfund National Priorities List
McCoy	O&M	Operations & Maintenance
Ridenour	OAR	Oregon Administrative Rule
Link	OATT	Open Access Transmission Tariff

Ridenour	ORS	Oregon Revised Statute
Link	PCAM	Power Cost Adjustment Mechanism
Foster-Wetzsteon	PCB	Polychlorinated biphenyls
McCoy	PGE	Portland General Electric Company
Foster-Wetzsteon	PHSS	Portland Harbor Superfund Site
McCoy	Power Planner	S&P Market Intelligence Power Planner
Foster-Wetzsteon	PRP	Potentially responsible party
Link	PTC	Production Tax Credit
Link	RAC	Renewable Adjustment Clause
Link	REC	Renewable Energy Credit
Link	RFP	Request for Proposals
Foster-Wetzsteon	RM	River Mile
Foster-Wetzsteon	RM11E	River Mile 11 East project area
Ridenour	RMA	Rate Mitigation Adjustment
Foster-Wetzsteon	ROD	Record of Decision
Link	ROE	Return on Equity
Link	ROR	Rate of Return
Link	RPS	Renewable Portfolio Standard
Bulkley	RRA	Regulatory Research Associates
Weems	S&P	Standard and Poor credit rating agency
Walker	SAE	Statistically adjusted end-use
McCoy	SB	Senate Bill
Bulkley	SCE	Sothern California Edison Company
Walker	Staff	Oregon Public Utilities Commission Staff
Link	TAM	Transition Adjustment Mechanism
Branch	Test Year	January 1, 2027 to December 31, 2027
Branch	Utah Plants	Hunter and Huntington plants
McCoy	WRAP	Western Resource Adequacy Program
Weems	Test Period	January 1, 2027 - December 31, 2027

CERTIFICATE OF SERVICE

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

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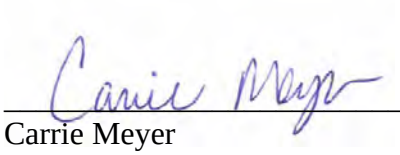

Carrie Meyer
Manager, Discovery & Regulatory Operations

CERTIFICATE OF SERVICE

I certify that a true and correct copy of **PacifiCorp's Application and Direct Testimony & Exhibits in Docket UE 470** was served on the parties listed below via electronic delivery in compliance with OAR 860-001-0180.

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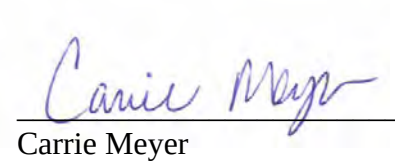
Dated this 5th day of May 2026.



Carrie Meyer
Manager, Discovery & Regulatory Operations

Docket No. UE 470
Exhibit PAC/100
Witness: Ryan L. Flynn

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Ryan L. Flynn

May 2026

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ATTACHED EXHIBIT

Exhibit PAC/101—Maps of PacifiCorp's Service Territory

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power.

A. My name is Ryan L. Flynn, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as the President of the Pacific Power division of PacifiCorp.

Q. Please summarize your professional experience.

A. I have a Bachelor's degree from Willamette University and a law degree from George Washington University. I have worked as a Congressional staffer and a lawyer for Troutman Pepper Locke in Washington, D.C. and Davis Wright Tremaine in Seattle, Washington. I joined PacifiCorp in 2006 and served in various positions in PacifiCorp's legal department. In 2018, I became Senior Vice President and Chief Legal Officer for Pacific Power, leading the legal, communications, and government affairs teams. In 2024, I was appointed President of Pacific Power, where I am currently responsible for regional strategy and engagement, customer and community affairs, government affairs, and regulatory affairs.

Q. Have you testified in other regulatory proceedings?

A. Yes. I have testified on various matters in the states of Oregon, California, and Washington.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in this case?

A. I provide an overview of PacifiCorp, including its utility service in Oregon, and briefly describe the proposed application for PacifiCorp's 2027 general rate case.

Further, I discuss the steps the company has determined are necessary to strengthen its financial stability and allow for continued access to capital markets to operate its business. Finally, I introduce the company witnesses that provide direct testimony in support of PacifiCorp's rate request.

III. DESCRIPTION OF PACIFICORP AND OREGON SERVICE AREA

Q. Please provide a description of PacifiCorp's operations.

A. PacifiCorp is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. PacifiCorp consists of two core business units: (1) Pacific Power, which supplies electricity to retail customers in Oregon, Washington, and California, and (2) Rocky Mountain Power, which supplies electricity to retail customers in Utah, Wyoming, and Idaho.

As an investor-owned, multijurisdictional electric utility, PacifiCorp provides retail electrical service to approximately 2.1 million retail electric customers in six western states. PacifiCorp operates two balancing authority areas that together comprise the largest privately owned and operated grid in the Western United States. PacifiCorp owns, or has interests in, thermal, hydroelectric, wind-powered, solar, and geothermal generating facilities. PacifiCorp provides wholesale transmission service under its open access transmission tariff approved by the Federal Energy Regulatory Commission and owns or has interests in approximately 17,700 miles of transmission lines.

Q. Please describe PacifiCorp's Oregon service area.

A. In Oregon, PacifiCorp serves over 667,000 customers. Maps of the company's service territory are provided in Exhibit PAC/101. PacifiCorp's Oregon service area is

comprised of urban and rural areas across varied geographic regions in Oregon including coastal, central, eastern, northern, southern, and the Willamette Valley. PacifiCorp serves on average approximately 29 customers per square mile.[1] Additionally, PacifiCorp has a generation capacity of 591 megawatts in Oregon and currently owns and operates 3,068 miles of transmission lines and 19,887 miles of distribution lines. PacifiCorp's sales and revenues are distributed among residential customers, small businesses, and large businesses. Table 1 below provides the number of retail customers and annual usage by customer class as forecasted for 2027.

Table 1 – Oregon Customers and Annual Usage by Class

Customer Class	Number of Customers	Annual Usage (Megawatt-Hours)
Residential	577,367	5,718,475
Commercial	84,330	8,715,838
Industrial	1,637	1,363,185
Irrigation	7,811	245,889
Lighting	1,623	28,888

Q. What is PacifiCorp's core principle in providing electric service to its customers?

A. PacifiCorp's core principle is to provide energy solutions in the form of safe, reliable, and affordable energy to all its customers. PacifiCorp has upheld this ideal for over 110 years and remains steadfast in this commitment despite increasingly challenging

[1] In contrast, Portland General Electric serves on average 231 customers per square mile. *See*, https://portlandgeneral.com/about/info/quick-facts 922,444 retail customers across 4,000 square miles.

conditions associated with changing economics, public policies, emerging and maturing technologies, increased severity and frequency of wildfires, unprecedented large load growth, and decarbonization of the grid. Despite these challenges, the company has continued to deliver safe and reliable electric service at a low cost. PacifiCorp's efficient operations for customers have resulted in the company's average price being approximately 9 percent lower than the national average for investor-owned utilities, which is about 16.50 cents per kilowatt-hour based on a typical residential bill of $165 per month (1,000 kilowatt-hours) using rates in effect January 1, 2025, as reported in the Edison Electric Institute Winter 2025 Typical Bills and Average Rates Report. PacifiCorp recognizes the need to change and adapt to meet these challenges while maintaining focus on its long-time core principle.

IV. PACIFIC POWER'S CURRENT RATE FILING

Q. Why is PacifiCorp filing a rate case at this time?

A. As I discuss further below, in this proceeding, the company is requesting a rate increase that is driven by the increasing costs of operations, capital investments needed to serve customers, and increased costs for insurance coverage.

The company is facing rising costs across the board since the 2025 general rate case.[2] Drivers of the requested overall rate change include capital investments, such as the Willamette River Crossing distribution project, inflationary pressures on operations and maintenance expenses, and increased insurance costs due to wildfire risk. Company witnesses Rick T. Link and Shelley E. McCoy address these rate case drivers in their testimonies.

[2] *In the Matters of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket Nos. UE 433, UM 2116, UM 2220, and UM 2161 (cons.), Order No. 24-447 at 1-4 (December 19, 2024).

PacifiCorp recognizes that its requested increase comes at a time when customers are facing increasing prices for all necessities. Consequently, as discussed in more detail below, the company's proposals in this proceeding are aimed to greatly mitigate net rate impacts for customers.

Q. Please describe what PacifiCorp is proposing for its 2027 general rate case.

A. For this proceeding, PacifiCorp proposes a total rate increase, including proposed changes to adjustment schedules and the announced sale of PacifiCorp's Washington service area and certain Washington-based assets (Service Area Transfer), of approximately $170.7 million, or 8.6 percent. In addition, PacifiCorp proposes adjustments related to the announced sale of PacifiCorp's Washington service area and certain Washington-based assets to Gem Sub LLC, an affiliate of Portland General Electric Company (Service Area Transfer), which result in an additional overall net increase of $3.0 million or 0.1 percent.

PacifiCorp proposes that the overall rate change occur in two steps. First, PacifiCorp proposes an interim increase of $55.1 million or 2.8 percent effective thirty days after this filing, June 4, 2026, subject to refund. Second, assuming interim rates are approved, a subsequent rate increase of $115.6 million or 5.7 percent would occur effective July 15, 2027, producing a total rate change of $170.7 million. The adjustments resulting from the Service Area Transfer would occur when the transaction closes or the final general rate case change takes effect, whichever comes later. Understanding our customers' affordability concerns, the company's proposals in this proceeding are aimed at minimizing the impact to customers by timing rate increases to occur in close proximity with other rate decreases.

Q. How will the Service Area Transfer more broadly impact PacifiCorp's Oregon customers beyond the impact in this general rate case?

A. PacifiCorp estimates the transaction will provide Oregon customers with an annual net benefit of $11.7 million for the first three years after closing, reflecting changes to net power costs (NPC), non-NPC revenue requirements, and increased resource adequacy, as well as a credit returning a portion of the goodwill value of the business being sold in the transaction. NPC-related impacts are addressed in the 2027 Transition Adjustment Mechanism filing in Docket UE 469, while non-NPC costs and credits are supported by testimony and exhibits from company witnesses McCoy and Judith M. Ridenour. As noted above, PacifiCorp's proposed treatment of the Service Area Transfer in this case will result in a small overall net rate increase of 3.0 million or 0.1 percent.

Q. Why is PacifiCorp requesting interim rates as part of its general rate case?

A. Interim rates are critical in this case because PacifiCorp is facing uniquely challenging financial circumstances, as discussed in more depth in the testimony of company witness M. Ryan Weems. The company's Oregon earnings are well below its authorized return on equity, as discussed by witness McCoy, and recent credit rating downgrades have increased borrowing costs and constrained access to capital, impairing PacifiCorp's ability to make needed system investments as discussed by witness Weems. Providing a near-immediate rate increase is necessary to enable PacifiCorp to maintain sufficient cashflows and liquidity to continue to operate the business in a manner that is necessary to serve Oregon customers and support Oregon energy policy while limiting impacts to the company's credit metrics. Approving

interim rates will also allow the company to defer the final rate increase resulting from this case by over three months, from the end of the suspension period, April 5, 2027, to July 15, 2027.

Importantly, even with interim rates, customer bills will remain largely unchanged in the near-term because on May 1, 2026, the company ended its surcharge related to the 2022 Power Cost Adjustment Mechanism and the proposed interim rates are designed to essentially offset that reduction, as discussed by company witness Link. Moreover, when coupled with other expected rate changes in the coming year, the proposed 8.6 percent increase here will be largely offset, as discussed by company witness Link. Ultimately, PacifiCorp's interim rate proposal spreads rate impacts over time and mitigates customer bill effects. Interim rates are just and reasonable because they will help stabilize PacifiCorp's financial position while reducing rate volatility for customers.

PacifiCorp's interim rate proposal is explained in further detail in the testimony of company witnesses Link, Weems, McCoy, and Ridenour.

Q. What changes have occurred since PacifiCorp last filed a rate case in February 2024 (2025 general rate case)?

A. Since PacifiCorp filed its 2025 general rate case, PacifiCorp's financial position has continued to deteriorate and the company has taken several extraordinary actions to improve its liquidity as it faces mounting liabilities from wildfire. Most recently, PacifiCorp has been downgraded by credit agencies to one notch above junk status. In response, earlier this year, PacifiCorp announced the Service Area transfer in February 2026 and the potential sale of small portions of its Oregon service territory.

PacifiCorp also entered into a sale-leaseback transaction with its parent Berkshire Hathaway Energy for PacifiCorp's share of the Boardman-to-Hemingway transmission line and reduced its planned near-term capital expenditures. A discussion of PacifiCorp's financial condition and the measures the company is taking in response are included in the testimony of company witness Weems.

Q. Can you explain how the 2027 general rate case helps PacifiCorp improve its financial health?

A. Yes. The 2027 general rate case will help improve PacifiCorp's financial health by realigning base rates with the utility's current cost of providing service. By updating rates to reflect more current operating expenses, the rate case will allow PacifiCorp to recover its prudently incurred costs.

PacifiCorp is seeking timely recovery of increased operations and maintenance expense and capital investments that are essential to safely and reliably serve customers and support Oregon energy policy. Including these costs in rates allows PacifiCorp the opportunity to earn its authorized return, improve cash flow and improve its financial stability.

Q. Please summarize PacifiCorp's current financial position.

A. PacifiCorp has been under extraordinary financial pressure in recent years. Recently, on November 10, 2025, S&P Global downgraded PacifiCorp's credit rating from BBB to BBB-, putting PacifiCorp's credit at the lowest rating level that is still considered investment grade. There have been a series of credit downgrades and updates, stemming primarily from wildfire liability issues and adverse regulatory outcomes. As a result of these downgraded ratings, PacifiCorp's borrowing costs

have increased and its access to capital has decreased, both of which impede PacifiCorp's near-term ability to make the capital investments that are necessary to reliably operate the system.

Q. Is PacifiCorp sensitive to the impact that wildfires have had on the communities in the company's service territory?

A. Yes, wildfires have profoundly changed the face of many of the communities in which the company operates. PacifiCorp remains committed to working with communities and making the necessary investments in vegetation management, system hardening, public safety power shutoffs, and other advanced technologies and practices to ensure Oregonians receive cost-effective wildfire mitigation.

Q. How could the outcome of the *James* case impact PacifiCorp's rate case?

A. The outcome of the *James* case and wildfire litigation has had serious and direct impacts on the company's financial condition, access to capital, and risk profile. As mentioned previously, PacifiCorp is experiencing acute financial pressure. The *James* case has been explicitly cited by credit rating agencies as a material source of risk, particularly due to potential liability exposure, bonding requirements, and liquidity strain. However, the company's request in this case is based on the operating costs and capital expenditures that are necessary to serve the company's Oregon customers. Company witness Weems discusses the impact of the *James* case further in his testimony.

Q. What is the current procedural status of the *James* case and related appeals?

A. The Oregon Court of Appeals reversed and remanded the verdict from the *James* trial back to the trial court. However, the decision from the Court of Appeals could be

appealed to the Oregon Supreme Court. Additionally, at the time of this filing, there is still uncertainty if the damages trials will continue. Regardless of the procedural status of the *James* case, PacifiCorp continues to seek to improve its financial position so that the company can continue to make the necessary investments to support Oregon customers.

V. INTRODUCTION OF PACIFICORP WITNESSES

Q. How is PacifiCorp presenting this case?

A. PacifiCorp is presenting the following direct testimony in support of its application:

- In Exhibit PAC/200, **Rick T. Link**, Senior Vice President of Regulation and Planning, will describe the individual components of PacifiCorp's general rate case and the benefits that Oregon customers receive from the Gateway South transmission line.

- In Exhibit PAC/300, **M. Ryan Weems**, Senior Vice President and Chief Financial Officer, will provide PacifiCorp's overall cost of capital recommendation for the company, including a capital structure to maximize value and minimize risk for the benefit of Oregon customers.

- In Exhibit PAC/400, **Ann E. Bulkley**, Principal at The Brattle Group, provides an overview on PacifiCorp's requested Return on Equity.

- In Exhibit PAC/500, **Bryce K. Foster,** Director of Project Delivery, and **Jacqueline T. Wetzsteon,** Program Manager**,** support the costs associated with the Willamette River Crossing distribution project.

- In Exhibit PAC/600, **Jayson D. Branch,** Senior Vice President of Power Supply, provides an overview of the company's coal fuel stock balance and forecast for the test period, while assessing the coal fuel inventory levels and associated costs.

- In Exhibit PAC/700, **Travis R. Walker**, supports the company's sales and load forecast for the rate case test period and addresses previous issues related to the 2025 general rate case.

- In Exhibit PAC/800, **Shelley E. McCoy**, Director of Revenue Requirement, addresses the overall test year revenue requirement, the impact of the Washington Service Area Transfer, amortization of deferral balances, and interim rate relief.

- In Exhibit PAC/900, **Kenneth Lee Elder, Jr.**, Director of Pricing & Tariff Policy, provides PacifiCorp's cost of service study.

- In Exhibit PAC/1000, **Judith M. Ridenour**, Pricing and Cost of Service Specialist, discusses rate design, and how the proposed tariff changes recover the proposed revenue requirement to achieve fair, just, and reasonable prices for customers.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 470
Exhibit PAC/101
Witness: Ryan L. Flynn

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ryan L. Flynn

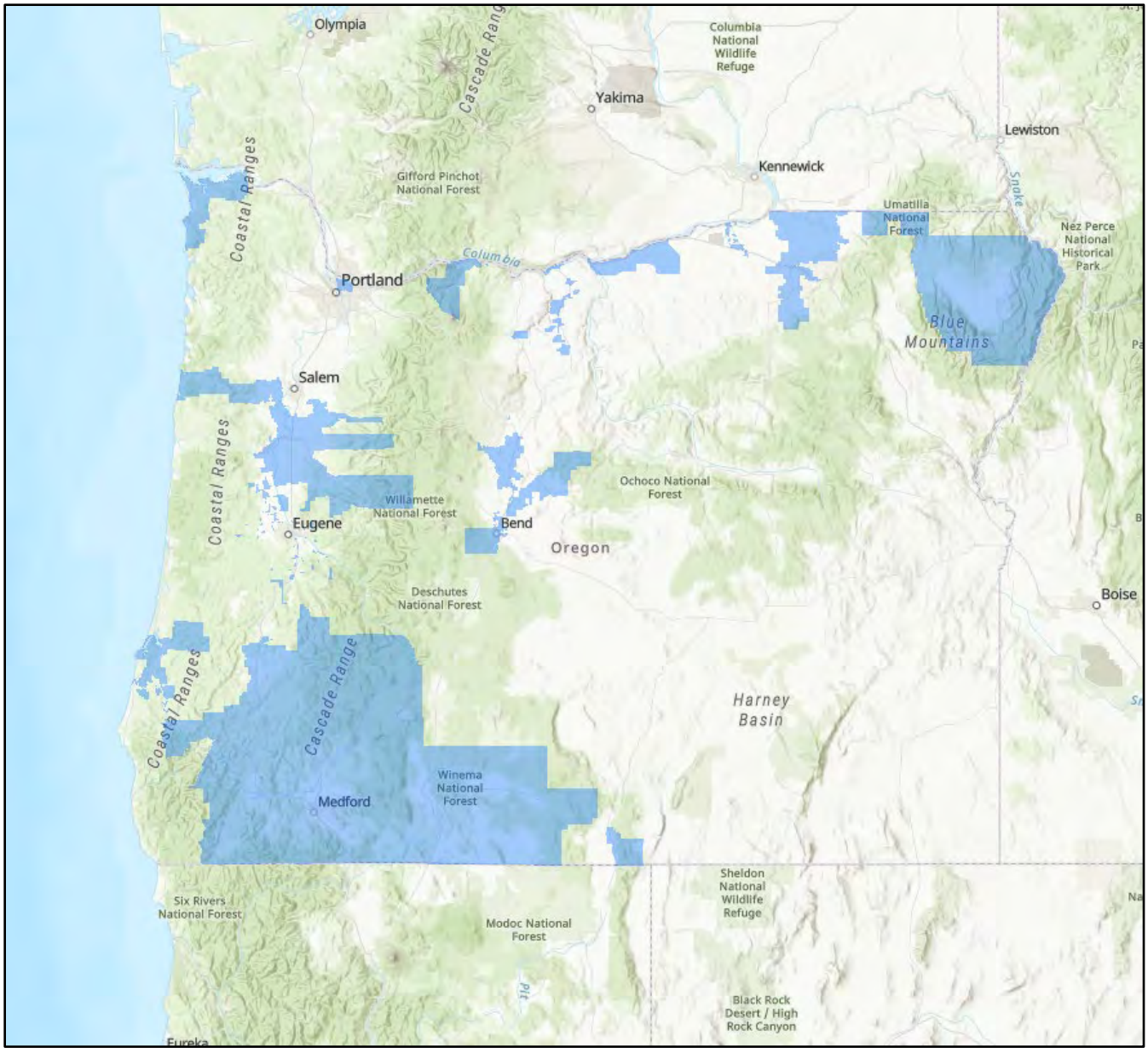
Maps of PacifiCorp's Service Territory

May 2026

Maps of PacifiCorp's Service Territory

Pacific Power Service Area

Oregon Territory Service Area



REDACTED
Docket No. UE 470
Exhibit PAC/200
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Rick T. Link

May 2026

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ATTACHED EXHIBITS

Exhibit PAC/201—Link 2025 Rate Case Direct Testimony

Exhibit PAC/202—Link 2025 Rate Case Reply Testimony

Confidential Exhibit PAC/203—Link 2026 RAC Direct Testimony

Exhibit PAC/204—Vail 2026 RAC Direct Testimony

Confidential Exhibit PAC/205—Mitchell 2026 TAM Direct Testimony

Confidential Exhibit PAC/206—Zacharia 2027 TAM Direct Testimony

Confidential Exhibit PAC/207—Brattle EDAM Benefits Study

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and current position with PacifiCorp d/b/a Pacific Power.

A. My name is Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Senior Vice President, Regulation and Planning.

Q. Please describe your education and professional experience.

A. I joined PacifiCorp in December 2003 and assumed my current position in December 2025. I have held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities, developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I have been heavily involved in developing PacifiCorp's integrated resource plans since 2013; have been directly involved in multiple resource request for proposal (RFP) processes; and performed economic analysis supporting a range of resource and transmission investment opportunities.

Before joining PacifiCorp, I was an energy and environmental economics consultant with ICF Consulting (now ICF International) from 1999 to 2003, where I performed electric-sector financial modeling of environmental policies and resource investment opportunities for utility clients. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Master of Environmental Management degree from Duke University in 1999.

Q. Briefly describe the responsibilities of your current position.

A. I oversee regulatory affairs in Oregon, Washington, and California, as well as PacifiCorp's resource planning and procurement functions, which include the integrated resource plan (IRP), structured commercial business, and valuation activities, across our six-state service territory. I also oversee the work of PacifiCorp's clean energy planning team, which is focused on producing plans in accordance with clean energy policies in Oregon and Washington.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in proceedings before the Public Utility Commission of Oregon (Commission), the California Public Utilities Commission, the Idaho Public Utilities Commission, the Utah Public Service Commission, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in this case?

A. First, I provide context for PacifiCorp's filing in this general rate case by describing why the company is proposing a change to its rates at this time and outline the key elements of its request.

Second, I discuss the company's request for interim rates to explain why it is consistent with the Commission's standard and how PacifiCorp moderated the request to address affordability.

Third, consistent with the Commission's decision from PacifiCorp's latest rate case in Docket UE 433, I discuss the actual benefits that Oregon customers are currently receiving from the Gateway South Segment F Aeolus–to–Mona/Clover

500 kilovolt (kV) transmission line (Gateway South). These benefits further support PacifiCorp's decision to move forward with its investments in Gateway South when it did—instead of delaying construction of this transformative asset for several years.

Q. Can you provide an overview of your policy testimony?

A. I first summarize the outcome of PacifiCorp's most recent general rate case and discuss the company's ongoing financial pressures, including earned returns that are below the Commission-authorized return on equity (ROE). I then describe the key elements of the current filing, including the proposed test period, requested rate of return, major cost drivers, treatment of deferred costs, and the impacts of the pending sale of PacifiCorp's Washington service area and certain Washington-based assets to a newly formed affiliate of Portland General Electric Company, Gem Sub LLC (Gem).

My testimony also addresses PacifiCorp's request to continue using the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol) for purposes of this rate case and explains why that approach is reasonable given ongoing stakeholder discussions and the expected Washington asset sale. Finally, I discuss the company's request for interim rates, including the rationale for that request, how it would work, and the resulting customer impacts when combined with other anticipated price changes. Overall, my policy testimony explains how PacifiCorp's proposals balance customer affordability with the company's need to stabilize its financial position and maintain access to capital necessary to provide safe and reliable service.

Q. What is your recommendation?

A. I recommend that the Commission approve PacifiCorp's rate increase including its interim rate proposal.

Q. Please provide an overview of your Gateway South testimony.

A. My testimony shows that while Gateway South has been in service for just over a year and a half, it has already provided Oregon customers with substantial benefits. These include:

- *Reduced wind curtailment*. In a single 11-month period in 2025, Gateway South avoided almost 107 days of cumulative hourly wind curtailments. That amounts to enough energy to power 35,273 Oregon homes for an entire year. These wind curtailments have continued to decrease through 2026, even with an additional 1,361 MW of Wyoming wind resources that required Gateway South to interconnect. Only [redacted] percent of wind generation was curtailed from December 2025 through March 2026, after Gateway South came online, compared to [redacted] percent from December 2023 to March 2024, before Gateway South came online. These reduced curtailments occurred despite total Wyoming wind generation more than doubling in the latter period ([redacted] MWh compared to [redacted] MWh, respectively).
- *Power cost benefits*. Oregon-allocated net power costs (NPC) decreased by $63 million for 2025 as a direct result of Gateway South, including $44 million in power cost savings, and $19 million in increased quantifiable production tax credit (PTC) benefits. Recent analyses for 2027 confirm these benefits, as NPC would increase—conservatively—by $117.5 million if Gateway South was

removed from PacifiCorp's transmission system. This is a conservative figure, as this analysis removes only Gateway South, while preserving the NPC benefits of the 1,361 MW of new wind resources that required Gateway South to interconnect and deliver energy to load. As noted in prior proceedings, these non-emitting resources can only interconnect to PacifiCorp's system with the addition of Gateway South.

- *House Bill (HB) 2021 Compliance*. The wind resources enabled by Gateway South have contributed to an 8.4 to 19.6 percent reduction in PacifiCorp's Oregon-allocated greenhouse gas emissions from 2023 levels. This is the single largest reduction in PacifiCorp's Oregon-allocated emissions since the company began reporting emissions to the Oregon Department of Environmental Quality (DEQ).
- *Renewable Portfolio Standard (RPS) Compliance*. Gateway South, and the renewable energy credits (RECs) from wind resources that would otherwise be unable to interconnect with PacifiCorp's system without the transmission line, amount to approximately 30 percent of PacifiCorp's 2030 RPS obligation.
- *REC Revenue*. The Commission recently allowed PacifiCorp to sell excess Oregon-allocated RECs and return 90 percent of the net proceeds from these sales to Oregon retail customers each year.[1] To the extent that Gateway South-enabled RECs result in excess Oregon-allocated RECs, customers will receive 90 percent of the net proceeds from these sales.

[1] *In re PacifiCorp's Request to Sell RECs*, Docket No. UE 467, Advice No. 26-008.

- *Increased Resource Adequacy, Interconnection Capacity, and Reliability Benefits.* Gateway South increased PacifiCorp's interconnection capacity by over 2 gigawatts (GW). The incremental interconnection capacity has enabled wind resources to come online, which reduces market reliance and improves resource adequacy. Addition interconnection capability provides opportunity to add additional resources in this wind-rich area to provide future resource adequacy benefits. Moreover, Gateway South provides robust reliability benefits.
- *2027 Revenue Requirement Benefits.* Focusing on 2027 alone, Oregon rates would be approximately $11.4 million higher without Gateway South.

Q. What is your recommendation for Gateway South?

A. Given the material benefits that Oregon customers have already received since Gateway South came online and will continue to receive over the remaining life of this transmission asset, PacifiCorp requests the Commission allow the company to recover its full rate of return on Gateway South. Otherwise, PacifiCorp will continue to under-recover on this resource, amounting to an over $10 million annual disallowance since the resource began serving Oregon customers in 2025.

III. POLICY

A. Previous Rate Case History

Q. Please discuss PacifiCorp's most recent general rate case and its outcome.

A. On February 14, 2024, PacifiCorp filed its most recent Oregon general rate case in Docket UE 433 (2025 Rate Case), requesting an overall increase in Oregon revenues of approximately $322.3 million, or 17.9 percent, effective January 1, 2025. During the course of the proceeding, PacifiCorp reduced its request to approximately

$208.8 million, or an 11.2 percent increase, reflecting the removal of certain proposals and adjustments made in response to issues raised by parties and Commission Staff.

Following extensive discovery, testimony, an evidentiary hearing, and briefing, the Commission issued Order No. 24-447 on December 19, 2024. In that order, the Commission approved an increase to PacifiCorp's Oregon revenue requirement resulting in an approximately 8.5 percent increase to base rates, effective January 1, 2025. When combined with other contemporaneous rate changes from separate dockets, including power cost adjustments, the overall net increase to Oregon customers taking effect on January 1, 2025, was approximately 7 percent.[2]

The Commission's order resolved a broad range of contested issues, including cost of capital, wildfire restoration and insurance cost recovery, coal plant exit dates, transmission investments, and customer affordability measures. Among other determinations, the Commission authorized a return on equity of 9.5 percent,[3] approved recovery of a portion of deferred wildfire restoration[4] and insurance costs subject to sharing mechanisms,[5] updated certain coal plant exit orders and depreciation schedules,[6] and adopted new rate design provisions for very large load customers.[7] The approved rates and tariff changes became effective January 1, 2025.

[2] *In re PacifiCorp's 2024 Rate Case*, Docket Nos. UE 433, UM 2116, UM 2220, and UM 2161 (cons.), Order No. 24-447 at 1-4 (December 19, 2024).
[3] *Id*. at 13.
[4] *Id*. at 18-20.
[5] *Id*. at 24-25.
[6] *Id*. at 33-35.
[7] *Id*. at 99-102.

B. Rate Case Overview

Q. What is the purpose of this section of your direct testimony?

A. In this section of my testimony, I discuss the individual components of PacifiCorp's filing, including the cost drivers leading to the filing.

Q. Why is PacifiCorp filing a rate case at this time?

A. As discussed by company witness Ryan L. Flynn, PacifiCorp continues to face cost and liquidity pressures following the 2025 Rate Case. Even with the last rate increase approved in the 2025 Rate Case, as witness Shelley E. McCoy explains, the expected ROE for the test period in this case would be 7.2 percent without the current filing as compared to the currently authorized ROE of 9.5 percent. Affording a utility the opportunity to earn its ROE allows it to receive financing for capital investments at reasonable costs, which in turn allows the utility to deliver safe and reliable service at low costs to its customers.

Q. What test period is PacifiCorp proposing in this rate proceeding?

A. The test period the company is proposing is a forecast test year for the 12 months ended December 31, 2027. The testimony of company witness McCoy discusses the development of the test year.

Q. What rate of return (ROR) is PacifiCorp requesting in this case?

A. PacifiCorp is requesting approval of an overall ROR of 7.56 percent. The overall ROR is comprised of a 9.7 percent ROE as supported by company witness Ann E. Bulkley. As explained by company witness M. Ryan Weems, PacifiCorp is requesting a capital structure that is comprised of 50 percent equity and 50 percent long-term debt. Notably, and in recognition of affordability challenges, the company is

requesting an authorized ROE at the lower end of the range recommended by company witness Bulkley. PacifiCorp's proposed ROE balances the impact on customers with the prevailing market conditions that support a higher ROE, as described by company witness Bulkley, and PacifiCorp's increased need to access capital at a reasonable cost in light of the company's financial condition as discussed by company witnesses Flynn and Weems. Company witness McCoy applies the overall ROR to the company's cost of service.

Q. What allocation methodology did PacifiCorp use to allocate costs in this rate case proceeding?

A. PacifiCorp used the 2020 Protocol to allocate costs among states in this proceeding. The Commission approved use of the 2020 Protocol through December 31, 2025.[8] While the 2020 Protocol expired at the end of 2025, it is the most recent allocation methodology approved by the Commission and was used to set current rates. PacifiCorp proposes to continue its use for ratemaking purposes until a new allocation methodology is approved.

Q. Why is PacifiCorp proposing that costs be allocated using the 2020 Protocol for this case?

A. In Docket UM 2401, pending before the Commission, the company requested approval of the 2026 Protocol. In the 2026 Protocol the company tried to balance near-term needs to address diverging state policies and the disallowance of carbon costs related to the Chehalis plant by proposing a first phase transition in resource allocation through the creation of two resource portfolios—one for resource

[8] Docket No. UM 1050, Order No. 23-229 (Jun. 30, 2023).

allocations to Wyoming, Idaho, Utah, Oregon and California and one for a fixed allocation to Washington. Fixing the allocation to Washington, which included 100 percent allocation of Chehalis, would protect other customers from the company's need to meet Washington's energy policy goals, including removing coal from rates by 2026, while the other states continue to retain the benefits of sharing system cost using dynamic allocation factors. The Washington Utilities and Transportation Commission approved the Washington 2026 Protocol in December 2025.[9]

On February 15, 2026, PacifiCorp executed an agreement with Portland General Electric Company and Gem to sell its Washington service area and certain Washington-based distribution, transmission, and generation assets (the Service Area Transfer).[10] Once all necessary conditions in the Asset Purchase and Service Area Transfer Agreement (the Agreement) are met, including obtaining state and federal approvals, the transaction will close and the costs of PacifiCorp's remaining assets will no longer be allocated to customers in Washington, minimizing the immediate need for a successor allocation methodology to the 2020 Protocol that adjusts resources to account for Washington's exit from coal-fired resources.

PacifiCorp has attended recent meetings with parties from Oregon, Utah, Wyoming, and Idaho to discuss interjurisdictional allocations on March 2, 2026, March 20, 2026, and April 8, 2026. To allow more time for collaboration with parties from the remaining states and since there is no immediate need to solve removing

[9] *In re PacifiCorp's 2025 Power Cost Only Rate Case,* Docket No. UE-250224, Order No. 08 (Dec. 22, 2025).
[10] *E.g., In re PacifiCorp's Application for an Order Authorizing the Sale of Washington-Based Assets,* Docket No. UP 441, PAC/200, Link at 2-6. Assets include the Goodnoe Hills Wind Farm (94 MW), the Marengo I and II Wind Farms (234 MW), the Chehalis combined cycle gas turbine power plant (477 MW), transmission assets, including 393 miles of transmission lines, 10 substations (two will be jointly owned), and approximately 6,220 structures, and PacifiCorp's Washington-based distribution assets, including approximately 4,100 miles of distribution lines, 34 substations, and approximately 100,480 poles.

coal from Washington customers' rates, it is reasonable for the Commission to approve PacifiCorp's use of the 2020 Protocol for this case. Further, allowing PacifiCorp to move forward with this case using the 2020 Protocol avoids unnecessary disruption in ratemaking and provides stability and certainty that are particularly important at this time given the company's current financial position.

Q. If PacifiCorp's Washington jurisdiction allocates costs under the 2026 Protocol and the other five jurisdictions allocate costs under the 2020 Protocol, will the company over-recover its costs?

A. No. For many years, different methodologies have been used for allocating PacifiCorp's system costs to Washington and its other five states. This has resulted in more than 100 percent of the cost of some items being allocated to the six states, while other items have been less than 100 percent allocated. In docket UM 2401, the company has presented evidence that approval of the 2026 Protocol would result in a $14.9 million increase for Oregon customers indicating that under the 2020 Protocol PacifiCorp would actually under-recover its costs.[11] This would only be temporary though. Once the Service Area Transfer is completed, PacifiCorp would no longer serve retail customers in a state that uses a different interjurisdictional allocation methodology.

Q. Please describe the major components of PacifiCorp's rate request.

A. PacifiCorp is requesting a base $161.7 million increase that would take effect on July 15, 2027 if the company's interim rate proposal is approved, or on April 1, 2027 if the company's interim rate proposal is not approved. I describe PacifiCorp's interim rate

[11] *In re PacifiCorp's Application for Approval of 2026 Inter-Jurisdictional Allocation Protocol*, Docket No. UM 2401, PAC/400, McCoy at 5.

proposal later in my testimony. PacifiCorp also proposes updates to adjustment schedules outside of base rates beginning July 15, 2027, if the company's interim rate proposal is approved, or April 1, 2027, if the company's interim rate proposal is not approved, which will result in an additional $9.0 million increase.[12] The company proposes to update the amounts recovered through the Schedule 190 – Wildfire Mitigation Plan Cost Recovery Adjustment. Additionally the company proposes to amortize deferred amounts for costs associated with completion of the Rock Creek I and Rock Creek II wind generation plants, the delay in collection of the Renewable Adjustment Clause (RAC) from residential customers from January 1, 2026 until April 1, 2026 due to the requirements of the FAIR Act,[13] and increased insurance premiums. The company proposes amortizing the deferral for the delay of the residential RAC increase over three years and amortizing the other deferrals over one year.

Effective at the later of the rate case effective date or when the Service Area Transfer closes, PacifiCorp proposes an increase of $17.3 million to revenue requirement related to the non-NPC impact of the Service Area Transfer. Additionally, PacifiCorp proposes a credit of $40.0 million for a portion of the goodwill value of the business associated with the Service Area Transfer, which the company proposes to amortize through Schedule 96 - Property Sales Balancing Account Adjustment over three years (approximately $14.3 million per year).

[12] As described by PacifiCorp witness McCoy, the increase from the insurance deferral is dependent upon effective date. The $9.0 million increase referenced here is calculated assuming a June 4, 2026 interim rate change of 2.8 percent and a July 15, 2027 effective date for the general rate case.
[13] 2025 Oregon Laws Ch. 503, House Bill 3179.

The total increase requested for all of these components is $173.7 million. This case does not include a change to the level of NPC in rates for customers. Updates to the rates for NPC are addressed in the Transition Adjustment Mechanism (TAM), which includes additional impacts of the Service Area Transfer.[14]

Q. Please describe the major drivers of the base rate request that are unrelated to the Service Area Transfer.

A. The major drivers of PacifiCorp's requested increase in base rates are: (1) capital investments; and (2) operations and maintenance expense increases. For capital, this case includes a $907.7 million increase in the Oregon-allocated rate base from current rates. The increase in rate base is largely driven by transmission and Oregon distribution investments since the last rate case. This includes the cost of the Willamette River Crossing project which is necessary for remediation of the Portland Clean Harbor Superfund Site as explained in the testimony of witnesses Bryce K. Foster and Jacqueline T. Wetzsteon. These capital investments are required for the company to provide safe, reliable and low cost service to its customers. In this case, PacifiCorp is also requesting the full rate of return for Gateway South, which is discussed in detail later in my testimony. For operations and maintenance, PacifiCorp has continued to see inflationary pressures on expenses necessary to effectively operate its system. More details on these costs are in witness McCoy's testimony and exhibits.

[14] *In re PacifiCorp's 2027 Transition Adjustment Mechanism*, Docket No. UE 469.

Q. How does PacifiCorp propose handling the impacts of the Service Area Transfer in this case?

A. In Docket UP 441, the company is requesting Commission approval of the sale of certain Washington-based assets included in the Service Area Transfer. PacifiCorp estimates that the Service Area Transfer will result in an annual net benefit of $11.7 million for Oregon customers for the first three years after the transaction closes. This benefit includes an increase to non-NPC revenue requirement, a decrease to NPC revenue requirement, and resource adequacy benefits, as well as a credit that passes back a portion of the goodwill value of the business to customers.[15] The decrease to the NPC revenue requirement is reflected in the company's 2027 TAM application in Docket UE 469 and assumes the Service Area Transfer will close April 1, 2027.[16] In this case, PacifiCorp will address the non-NPC revenue requirement and the credit from the goodwill value of the business related to the Service Area Transfer. Since the closing date of the transaction is unknown, PacifiCorp proposes that the base increase adjustment and the credit in Schedule 96 - Property Sales Balancing Account Adjustment take effect on the later of the rate case effective date or the closing date for the Service Area Transfer. The cost and credit associated with the Service Area Transfer are identified in the testimony and exhibits of company witness McCoy. The base adjustment rate and Schedule 96 credit that will take effect upon closing of the Service Area Transfer are described by company witness Judith M. Ridenour.

[15] *In the Matter of PacifiCorp d/b/a Pacific Power, Application for an Order Authorizing the Sale of Washington-Based Assets,* Docket No. UP 441, PAC/200, Link at 11-14.
[16] *In the Matter of PacifiCorp. dba Pacific Power, 2027 Transition Adjustment Mechanism,* Docket No. UE 469, PAC/100, Zacharia at 7.

Q. Why is PacifiCorp proposing to include the impacts of the Service Area Transfer in this case?

A. The Service Area Transfer will necessitate removing the costs of the generation and transmission assets being sold from Oregon customer rates and, through application of the 2020 Protocol, change the Oregon allocation of the remaining resources and costs from a 6-state dynamic allocation to a 5-state dynamic allocation. To be more efficient, the company aligned the timing of this rate case with the application for approval of the Service Area Transfer so that both the company's current cost of service and need for a revenue requirement increase can be evaluated alongside the impacts of the Service Area Transfer for Oregon ratemaking.

Q. Why is the approval of the Service Area Transfer and its implementation in this general rate case in the public interest?

A. As explained in the application for approval of the asset sales that are part of the Service Area Transfer in Docket UP 441, approval of the asset sales is in the public interest because it supports the financial health of PacifiCorp which is needed to provide reasonably priced reliable service to Oregon customers. Further, asset sales will not harm PacifiCorp's Oregon customers because the underlying Service Area Transfer will positively impact Oregon customers and will help reduce risk.[17]

Q. Why is PacifiCorp proposing to implement the Service Area Transfer through a second rate change in this proceeding?

A. PacifiCorp acknowledges that the timing of this rate case and the Service Area Transfer is challenging. However, the Company has tried to structure this filing and

[17] *In the Matter of PacifiCorp d/b/a Pacific Power, Application for an Order Authorizing the Sale of Washington-Based Assets,* Docket No. UP 441, PAC/200, Link at 9-16.

the implementation of the Service Area Transfer transparently by (1) calculating the revenue requirement increase needed without consideration of the Washington sale, and then (2) proposing an adjustment to implement the revenue requirement impacts of the sale in the test period and initiate the credit to customers for the allocated shared of the goodwill value of the business once the transaction closes. By calculating these rate changes separately, customers are held harmless from rate changes to implement the Service Area Transfer until there is certainty on the transaction closure, which cannot occur until approval is received from all of PacifiCorp's six states and the Federal Energy Regulatory Commission.

Q. What is the proposed rate change for the Service Area Transfer?

A. The proposed rate change is an estimated net increase of $3.0 million, or 0.1 percent. This is comprised of a $17.3 million non-NPC base rate increase reflecting the removal of sold generation and transmission assets, change in allocation factors for a 5-state allocation, and an increase in wheeling revenue, offset in part by a proposed $14.3 million annual credit, including interest, in Schedule 96, Property Sales Balancing Account, for the proposed customer share of the goodwill value of the business. Witness McCoy provides more detail about the calculations for the revenue requirement impact associated with Service Area Transfer.

Q. Is PacifiCorp proposing updates to rate design?

A. Consistent with cost of service results, PacifiCorp is proposing to increase the residential basic charge for customers living in single-family dwellings from $14 to $17 per month and the basic charge for customers living in multi-family dwellings from $8 to $9. Otherwise, the company generally proposes to apply the rate change

on an equal percentage basis to the different functionalized prices for residential and non-residential rates. Company witness Ridenour provides more detail about proposed rates.

Q. What is the impact of PacifiCorp's proposed rate increase to customers?

A. The company proposed to recover the general rate case increase of $170.7 million in two steps: an interim increase of $55.1 million or 2.8 percent and an incremental general rate case increase of $115.6 million or 5.7 percent. Additionally, the company proposes a $3.0 million or 0.1 percent increase associated with the close of the Washington Service Area Transfer. However, these increases are offset by a recent $65.3 million or 3.2 percent decrease related to the end of the 2022 Power Cost Adjustment Mechanism (PCAM) amortization, the projected $55.7 million or 2.8 percent decrease for the 2027 TAM,[18] and the expected $95.7 million or 4.7 percent decrease related to the end of the amortization of the 2021, 2023 and 2024 PCAMs. Taken together, the impact of the rate case net of the anticipated TAM and PCAM changes is an overall average 2.1 percent decrease.

Residential customers will see no overall increase from the combination of the end of the 2022 PCAM amortization and the interim increase. Combining the interim increase, the incremental general rate case increase and the Service Area Transfer increase with the anticipated 2026 and 2027 TAM and PCAM related decreases, residential customers overall will see a modest combined 1.9 percent increase. Rate impacts are more fully described in the testimony of witness Ridenour.

[18] *In re PacifiCorp's 2027 Transition Adjustment Mechanism*, Docket No. UE 469, PAC/300, Ridenour at 4.

C. Interim Rates

Q. Is PacifiCorp requesting interim rates with the filing of its general rate case?

A. Yes. It is my understanding that ORS 757.215 authorizes utilities to request interim rates as an element of a general rate case filing. While I understand that the Commission generally disfavors interim rates and its policy is to grant interim rate relief only where the utility demonstrates that it faces severe financial distress that jeopardizes the continuing operation of the utility,[19] PacifiCorp is in such a situation now, as discussed below and in the testimony of company witness Weems.

Q. Please summarize PacifiCorp's interim rate proposal.

A. PacifiCorp proposes that $55.1 million, or about 32 percent of the company's total requested general rate case increase, take effect within 30 days of this filing, i.e., by June 4, 2026. In accordance with ORS 757.215, these interim rates would be subject to refund if the Commission later determines a refund is required.[20] As discussed further in the testimony of company witness McCoy, the requested amount reflects a portion of the approximately $98.5 million in incremental, known, and quantifiable costs that the company has already incurred or is currently incurring to serve Oregon customers. The company's interim rate proposal is based on its currently approved rate of return and capital structure to simplify the Commission's review. If the request for interim rates is granted, PacifiCorp proposes delaying the effective date for the final rate increase to July 15, 2027, to spread out the impacts to customers.

[19] *In re PGE's Selective Water Withdrawal Project Rate Proceeding*, Docket No. UE 204, Order No. 09-108 at 3 (Mar. 30, 2009); *In re PGE's Excess Pension Costs and Carrying Costs on Cash Contributions Proceeding*, Docket No. UM 1623, Order No. 16-257 at 3 (July 7, 2016).

[20] ORS 757.215(4). The company's proposal for addressing any required refund is discussed in the testimony of company witness Ridenour.

Q. Why is PacifiCorp proposing interim rates?

A. As discussed in the testimony of PacifiCorp witness Weems, the company has been under extraordinary financial pressure in recent years and is proposing interim rates to help it obtain the funding necessary to meet its liquidity needs and invest in meeting Oregon's policy goals. PacifiCorp's borrowing costs have increased and its access to capital has decreased, both of which impede PacifiCorp's near-term ability to make the capital investments that are necessary to reliably operate the system. Approval of interim rates will provide the immediate support the company needs to stabilize its financial position so it can deploy the capital needed to serve its customers and make investments needed to meet Oregon's existing and new policy goals, including clean energy goals.

Q. Why is PacifiCorp proposing to collect through interim rates an amount less than the full $98.5 million it expects to incur in 2026?

A. PacifiCorp voluntarily limited its interim rates request to address customer affordability concerns. Specifically, PacifiCorp requests a $55.1 million, or 2.8 percent, increase because this amount is offset by the reduction in rates for typical residential customers that occurred on May 1, 2026, related to the end of the amortization of the 2022 PCAM. The result is that the typical residential customer will see no net change in their rates from interim rates compared to the rates in effect prior to the end of the PCAM amortization. In other words, if interim rates are approved the typical residential customer's monthly bill will be the same as it was before May 1.

IV. GATEWAY SOUTH

A. Overview of Gateway South and Prior Proceedings

Q. Please describe Gateway South.

A. Gateway South is a 414-mile, 500 kV overhead transmission line between the Aeolus Substation, near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. Gateway South came online at the end of 2024, and to date, has enabled 1,361 MW of new wind generation to come online in eastern Wyoming. Given the geographic location of Gateway South, and subsequent contracting experiences, PacifiCorp reasonably expects that at least some portion of the remaining 669 MW of expanded interconnection capacity will be filled with low-cost wind resources. Utility commissions in Utah,[21] Idaho,[22] Wyoming,[23] Washington,[24] and California[25] have allowed PacifiCorp to fully recover the cost of Gateway South, inclusive of its full ROR.

Q. Please describe the Commission's prior review of Gateway South.

A. In its first review of Gateway South 2020, the Commission narrowly acknowledged this asset in PacifiCorp's 2019 IRP.[26] "For a major expenditure like Gateway south

[21] *In re PacifiCorp's 2024 Utah Rate Case*, Docket No. 24-035-04.
[22] *In re PacifiCorp's 2024 Idaho Rate Case*, Docket No. PAC-E-24-04, Order No. 36452 at 3 (Jan. 31, 2025).
[23] *In re PacifiCorp's 2024 Wyoming Rate Case*, Docket No. 20000-664-EM-24, Record No. 17547, Memorandum Opinion, Findings, and Order Approving Stipulation (Feb. 18, 2025); *In re PacifiCorp's 2023 Wyoming Rate Case*, Docket No. 20000-633-ER-23, Record No. 17252, Memorandum Opinion, Findings, and Order at 47 (Jan. 2, 2024).
[24] *In re PacifiCorp's 2023 Washington Rate Case*, Docket No. UE-230172, Order 08 at 1 (Mar. 19, 2024).
[25] *In re PacifiCorp's 2025 PTAM Capital Additions*, Advice Letter 766-E (Jul. 25, 2025).
[26] *In re PacifiCorp's 2019 IRP*, Docket LC 70, Order No. 20-186, at 21 (Jun. 8, 2020) ("We adopt Staff's other recommendations, including Staff's recommendation to acknowledge transmission items such as Gateway South only insofar as they are selected in the RFP. Our acknowledgement here is more limited than a typical acknowledgement, because the RFP is an immediate and clear next step that will test the costs and benefits of all generation-dependent transmission upgrades against each other.").

that has moved forward in time," the Commission noted, it "will examine the near-term customer costs" in subsequent RFPs.[27]

When the Commission acknowledged PacifiCorp's 2020 All Source RFP final short list the following year—inclusive of the resources that relied on Gateway South—the Commission noted that Gateway South would increase "regional electric system reliability, delivery of generation resources, and satisfaction of what may indeed be federal legal obligation."[28] However, the Commission remained concerned about whether PacifiCorp's planned investments in Gateway South were appropriately analyzed.[29] In particular, the Commission expressed misgivings about "discounting" the full cost of Gateway South based on the company's argument that its federal Open Access Transmission Tariff (OATT) obligations to provide interconnection and transmission service made certain transmission investments in eastern Wyoming unavoidable.[30] To address these concerns, the Commission scheduled a workshop and directed PacifiCorp to discuss the federal-state relationships around transmission decisions and obligations, and alternative financing of transmission investments if necessary.[31] The Commission also concluded that, in a future rate proceeding, it would look at typical prudence requirements, as well as "review of federal transmission obligations . . . and actual benefits and costs of the

[27] *Id.*
[28] *In re PacifiCorp's 2020AS RFP*, Docket No. UM 2059, Order No. 21-437, at 16 (Nov. 24, 2021).
[29] *Id.* at 15.
[30] Order No. 21-437 at 15-16 (opining that Gateway South "was selected because PacifiCorp's view of its OATT obligations supports acknowledgment of the portion of the line's costs that were excluded from resource selection modeling").
[31] *Id.*

project as built, with the opportunity to look at aspects like HB 2021 compliance, increased reliability, and diversified resources."[32]

While reviewing PacifiCorp's 2021 IRP one year later in 2022, the Commission cautioned PacifiCorp that the company's cost-benefit analyses lacked "the holistic explanation of costs and benefits that we expect companies to provide in the IRP and which stakeholders and ratepayers should expect to receive for a multi-billion-dollar resource addition."[33] This led the Commission to direct PacifiCorp to "produce the full cost information for [Gateway South] in the rate cases where it seeks to place them into rate base."[34] The Commission also explained that if PacifiCorp intended to rely on "PacifiCorp's obligation to fulfill interconnection requests under its Federal Energy Regulatory Commission jurisdictional OATT" to justify cost recovery of Gateway South, then that "issue will be ripe for decision" in the rate case.[35] And if PacifiCorp intended to "justify [Gateway South] in terms of benefits provided to Oregon customers," then the Commission "look[ed] forward to the development of that record for prudency review."[36]

[32] *Id.*
[33] *In the Matter of PacifiCorp's 2021 Integrated Resource Plan*, Docket No. LC 77, Order No. 22-178 at 11 (May 23, 2022).
[34] *Id.* at 12.
[35] *Id.*
[36] *Id.*

Q. Did PacifiCorp attempt to address the Commission's concerns, and provide what it believed were complete analyses of the costs and benefits provided by Gateway South, in its first rate case to recover its investments in Gateway South?

A. Yes. In Docket UE 433, I provided several analyses of the cost and benefits of Gateway South. These included: (a) analysis of changes to PacifiCorp's present-value revenue requirement caused by Gateway South across five price-policy scenarios;[37] (b) the same scenarios, adjusted for risk; (c) the same scenarios assuming Gateway South (and Gateway West) were unavoidable; (d) how removal of Gateway South would impact the company's resource portfolio by removing almost 2 GW of wind resources before 2030 alone, and by increasing exposure to market purchases by nearly 20 percent annually; (e) analyzed changes in system costs with and without Gateway South; (f) discussed additional REC benefits provided by the resources interconnected by Gateway South; (g) considered several sensitivities that could impact the company's analyses, including changes in capital costs and analyzing stochastic risk benefits; and (f) revisited my economic analyses to address impacts caused by the COVID-19 pandemic and the passage of the Inflation Reduction Act.[38]

PacifiCorp's evidence and briefing in Docket UE 433 also explained in depth why PacifiCorp's federal obligation to provide interconnection and transmission

[37] A price-policy scenario reflects market scenarios defined by different combinations of market price assumptions (i.e., wholesale power and natural gas) and carbon dioxide policy assumptions captured as price on emissions.
[38] Exhibit PAC/201—Link 2025 Rate Case Direct Testimony, at 28-36.

service made it reasonable to assume alternative facilities would be required to provide those services if Gateway South were not constructed.[39]

Q. Did PacifiCorp's cost-benefit analysis of Gateway South expressly include the full costs of Gateway South, consistent with the Commission's prior direction?

A. Yes. My testimony included a cost-benefit analysis of Gateway South's estimated annual revenue requirement results.[40] Under the heading "Cost of the Project," the exhibit included a line item for "Transmission GWS," which showed the total present-value revenue requirement of Gateway South of $1.261 billion (i.e., the "full cost" of Gateway South).[41] The exhibit also included a separate line item for the "Avoided Transmission – Base 230 kV" of $843 million.[42] Because the full cost of Gateway South and the avoided transmission investments were separately stated, it allowed the Commission to determine the overall cost-benefit results with and without the avoided transmission. This analysis provided the necessary information required to assess Gateway South based on its full costs, and without any assumed offset for alternative transmission facilities. The Commission confirmed this point when it described the cost-benefit results assuming the full cost of Gateway South.[43]

[39] *See, e.g.*, Docket No. UE 433, PacifiCorp's Opening Brief at 55-60 (Oct. 14, 2024).
[40] "2025 Rate Case Transmission Projects Analysis" Workpaper.
[41] *Id.*
[42] *Id.*

[redacted]

Q. Did PacifiCorp address concerns regarding whether it should have delayed investments in Gateway South?

A. Yes. I detailed PacifiCorp's decision to prioritize the construction of Gateway South, as the line would allow for a significant interconnection of new generation resources to address a significant capacity deficit—starting at 1,071 MW in 2021 and increasing to over 6,600 MW by 2040. In 2025, the first full year that Gateway South would be online, this resource need was 1,627 MW.[44] I also analyzed the timing of when Gateway South should come online, which demonstrated that without Gateway South (and Gateway West), the company's preferred portfolio would have been $260 million more expensive for customers, primarily due to increased exposure to and volatility of market prices, loads, hydro generation, and unplanned outages.[45] Finally, I highlighted the fact that Internal Revenue Service guidance at the time was clear that the only way the 2 GW of wind facilities that depended on Gateway South would receive PTCs was if each resource came online before 2026.[46]

Q. What was your conclusion from these analyses?

A. I concluded that PacifiCorp's estimates of both the forecasted benefits that Gateway South would provide Oregon customers, as well as the timeline to invest in this resource to come online before 2026, supported the prudency of the company's decisions.

[44] Exhibit PAC/202—Link 2025 Rate Case Reply Testimony, at 6-8.
[45] *Id.* at 8-9 (citing to Docket No. LC 77, PacifiCorp's 2021 IRP, Vol. I: Chapter 9 – Modeling and Portfolio Selection Results at 274 (Sept. 1, 2021)).
[46] *Id.* at 12-13.

Q. Did the Commission agree with your conclusion?

A. Partially. After reviewing PacifiCorp's analyses, and concluding that Gateway South would be used and useful once placed in service and would provide customer benefits on the rate-effective date,[47] the Commission noted that PacifiCorp "failed to provide sufficient analysis to justify its decision to construct the line sooner rather than later."[48] The Commission further identified that in order to receive a full return on Gateway South, PacifiCorp must demonstrate "in its next rate case, that the benefits identified in planning have materialized to produce a net benefit to customers."[49]

Q. Did PacifiCorp request recovery of Gateway South in a subsequent Oregon proceeding?

A. Yes. In 2025, PacifiCorp requested recovery of 590 MW from two wind resources (Rock Creek I and II), as well as full cost recovery of PacifiCorp's investment in Gateway South, in a RAC proceeding.[50]

Q. Did your testimony in that proceeding address the benefits that Oregon customers are receiving from Gateway South?

A. Yes. I confirmed that the forecasted benefits of Gateway South have largely materialized, and that Oregon customers will continue to benefit from this resource over its remaining 65-year service life. These benefits included increased resource diversity that provides substantial net power cost benefits and reduced curtailment of wind facilities. The addition of non-emitting resources enabled by Gateway South, and the reduction in wind curtailments, also helps PacifiCorp make progress toward

[47] Docket No. UE 433, Order No. 24-447 at 40 (Dec. 19, 2024)
[48] *Id.* at 42.
[49] *Id.*
[50] *In re PacifiCorp's 2026 RAC*, Docket No. UE 451.

meeting its compliance obligations under HB 2021 and Oregon's RPS.[51] Company witness Richard A. Vail discussed the increased reliability benefits provided by Gateway South specifically, and increased transmission capacity in general.[52]

Q. Did the Commission agree to allow PacifiCorp to receive the full rate of return for Gateway South in the RAC?

A. No. The Commission concluded as a matter of law that the Commission's 2024 rate case decision precluded recovery of Gateway South in a RAC proceeding, and that "associated transmission" in Oregon's RPS cost-recovery statute did not include Gateway South.[53]

Q. Did the Commission consider PacifiCorp's evidence in the case?

A. Not substantively. The Commission noted that the "complexity of the issues presented counsels that a general rate case is the appropriate forum for the comprehensive evidentiary review required to evaluate the analysis we required of PacifiCorp in Order No. 24-447."[54]

Q. Did PacifiCorp seek additional guidance from the Commission on what analysis it should provide for the Commission's review of Gateway South?

A. Yes. In PacifiCorp's request for reconsideration of the Commission's 2026 RAC decision, the company requested that the Commission "clarify what additional information and analysis will assist the Commission in making the determination necessary for full recovery" for Gateway South.[55] PacifiCorp "is prepared to provide

[51] Confidential Exhibit 203—Link 2026 RAC Direct Testimony.
[52] Exhibit PAC/204—Vail 2026 RAC Direct Testimony.
[53] Order No. 25-505, at 13-14.
[54] *Id.* at 13.
[55] *In re PacifiCorp's 2026 RAC,* Application for Reconsideration, at 7 (Feb. 6, 2026).

the information and analysis that the Commission determines is necessary but requires additional guidance in order to do so."[56]

Q. Did the Commission provide this guidance?

A. No. The Commission declined to reconsider its decision, or provide additional guidance for the analysis it requires for review of PacifiCorp's investments in Gateway South.[57]

Q. You have presented information and analyses to this Commission in the IRP, RFP, general rate case, and RAC dockets since 2019. Do you understand what analyses PacifiCorp has failed to provide?

A. I do not. However, in the section below, I detail the tangible and material customer benefits that Gateway South has provided for Oregon customers, that support PacifiCorp's decision to construct the line sooner rather than later.[58]

While my testimony in this proceeding focuses on the Commission's request for additional evidence regarding net customer benefits, as noted in each prior Gateway South proceeding, it is important to remember PacifiCorp's federal obligations to build Gateway South, or its functional equivalent, as a condition to being able to interconnect resources from the 2020 All-Source Request for Proposal.[59]

[56] *Id.* at 8.
[57] Order No. 26-076, at 1 (Mar. 17, 2026).
[58] Docket No. UE 433, Order No. 24-447 at 42 (Dec. 19, 2024) ("PacifiCorp must demonstrate "in its next rate case, that the benefits identified in planning have materialized to produce a net benefit to customers.").
[59] *E.g., In re PacifiCorp's 2026 RAC,* Docket No. UE 451, PacifiCorp Post-Hearing Brief, at 50 (Oct. 16, 2025) ("The Company's economic analysis rests on three conclusions: First, PacifiCorp is required by federal law to provide non-discriminatory interconnection service. Second, to provide safe and reliable interconnection service pursuant to 12 executed and legally binding interconnection agreements, PacifiCorp was required to construct significant transmission facilities. Third, federal law prohibits PacifiCorp from forcing the 12 interconnection customers to pay for the transmission facilities required for interconnection.").

B. Customer Benefits

Q. What benefits have Oregon customers received, and will continue to receive, over Gateway South's remaining 65-year service life?

A. Gateway South has provided, and will continue to provide, significant benefits to Oregon customers over its remaining service life. These benefits include reduced wind curtailments; lower NPC; improved compliance with PacifiCorp's HB 2021 and RPS requirements; additional opportunities for REC revenue; enhanced resource adequacy interconnection capability, and system reliability; and when focusing on a single year, provides a net revenue requirement benefit during the test period of this rate proceeding. I discuss each benefit below.

i. Reduced Wind Curtailments

Q. Has Gateway South decreased the volume of wind generation that otherwise would have been curtailed due to transmission congestion?

A. Yes. PacifiCorp conducted two studies to determine if there were any meaningful reductions in wind curtailments after Gateway South came online in December 2024. First, PacifiCorp compared Wyoming wind energy generation in 2024 and 2025, including the level of wind curtailments in January through November of each year. Second, PacifiCorp analyzed wind curtailments from December 3, 2023, through March 22, 2024, (before Gateway South and incremental wind resources came online); from December 3, 2024 through March 23, 2025 (after Gateway South and 481.5 MW of new wind resources came online); and from December 3, 2025, through March 23, 2026 (after Gateway South and 1,010.5 MW of new wind resources came online).

Both analyses confirmed that Gateway South has materially increased Wyoming wind generation by reducing curtailments, in addition to enabling significant incremental generation to interconnect and serve customers.

Q. What did PacifiCorp's first analysis conclude?

A. Before Gateway South came online, PacifiCorp's wind resources were curtailed to some degree an average [redacted] percent of the hours each month from January through November of 2024. This resulted in over [redacted] hours of curtailed wind generation, and [redacted] MWh of forgone wind energy in 2024.

After Gateway South came online, only an average [redacted] percent of PacifiCorp's wind fleet were curtailed in the hours of each month from January through November 2025. This resulted in only [redacted] hours where wind resources were curtailed, and only [redacted] MWh of foregone wind energy. In a single 11-month period, Gateway South avoided almost 107 total days of wind curtailments.

Q. Is there anything you would like to highlight about these reduced wind curtailments?

A. Yes. Gateway South materially reduced wind curtailments, even though an additional 481.5 MW of Wyoming wind resources came online in 2025.[60] Uncurtailed wind generation totaled [redacted] MWh in the 2025 study period, and [redacted] MWh in the 2024 study period. Only [redacted] MWh of Wyoming wind resources were curtailed in the 2025 period, when Gateway South was online ([redacted] percent of total generation), compared to [redacted] MWh in the 2024 period when Gateway South was not online ([redacted] percent). The results of PacifiCorp's curtailment analysis is summarized below in

[60] These wind resources include Anticline at 100.5 MW, Boswell Springs at 320 MW, and 61 MW from the partially constructed Rock Creek I wind project.

Table 1. In this table, figures for total wind generation represents the total potential amount of wind generation without any curtailments. "Total un-curtailed wind generation" represents the amount of wind generation that actually occurred accounting for any curtailments.

Table 1 – Gateway South Avoided Wind Curtailments

Wyoming Variable Energy Resources	Pre-Gateway South (1/1/2024 - 11/30/2024)	Post-Gateway South (1/1/2025 - 11/30/2025)
Number of Hours Curtailed	[redacted]	[redacted]
Percent of Hours Curtailed	[redacted]	[redacted]
Total Wind Generation (MWh)	[redacted]	[redacted]
Total Un-Curtailed Wind Generation (MWh)	[redacted]	[redacted]
Total Curtailed Volume (MWh)	[redacted]	[redacted]
Percent of Total Gen Curtailed	[redacted]	[redacted]

Q. In terms of Oregon residential usage, what are the household impacts from this increased wind generation and avoided wind curtailments?

A. Gateway South allowed wind generation to increase by [redacted] MWh in the 11-month period in 2025 compared to the prior 11-month period in 2024. A comparison of data between these two timeframes also shows that wind curtailments were reduced by [redacted] MWh. In terms of household usage, the increase in wind generation enabled by Gateway South equates to the average energy needs for 312,659 Oregon homes. The annual energy from avoided wind curtailments equates to the average energy needs for 35,273 Oregon homes.

Q. What additional analysis has PacifiCorp done to evaluate the avoided wind curtailment benefits of Gateway South?

A. PacifiCorp analyzed three separate periods to analyze pre- and post-Gateway South wind curtailments, as new wind resources from the 2020 All Source RFP also came

online. The first two periods, December 3 through March 23 in 2023/2024 and 2024/2025, were included in PacifiCorp's 2025 RAC proceeding, and provided Gateway South benefits from the online date of the resource, through the date of filing the RAC. To allow for more long term comparisons of wind curtailments, my testimony below analyzes curtailments from December 3 through March 23 for 2025/2026 as well. These analyses confirm that Gateway South continues to materially reduce wind curtailments, even with over 1 GW of additional wind resources coming online in the area.

For example, the first period indicated that [redacted] percent of total wind generation was curtailed before Gateway South came online, yet only [redacted] and [redacted] percent of total wind generation was curtailed in the second and third study periods when Gateway South was online. This is despite total Wyoming wind generation in the third period being more than double Wyoming wind generation in the first study period ([redacted] MWh compared to [redacted] MWh). The data are summarized in Table 2.

Table 2—Gateway South Avoided Wind Curtailments

Wyoming Variable Energy Resources	Pre-Gateway South (12/3/2023 - 3/22/2024)	Post-Gateway South (12/3/2024 - 3/23/2025)	Post-Gateway South (12/3/2025 – 3/23/2026
Number of Sample Hours	[redacted]	[redacted]	[redacted]
Number of Hours Curtailed	[redacted]	[redacted]	[redacted]
Percent of Hours Curtailed	[redacted]	[redacted]	[redacted]
Total Wind Generation (MWh)	[redacted]	[redacted]	[redacted]
Total Un-Curtailed Wind Generation (MWh)	[redacted]	[redacted]	[redacted]
Total Curtailed Volume (MWh)	[redacted]	[redacted]	[redacted]
Percent of Total Gen Curtailed	[redacted]	[redacted]	[redacted]

ii. Decreased Net Power Costs

Q. Has PacifiCorp quantified the net power cost savings to Oregon customers created by Gateway South for 2026?

A. Yes. Excluding non-NPC revenue requirement costs of Gateway South, the additional wind and transmission capacity provided by Gateway South reduces Oregon customer rates by $63 million in 2026. As discussed in the testimony of PacifiCorp witness Ramon Mitchell in the company's 2026 TAM filing, this $63 million reduction in rates for Oregon customers includes $44 million in NPC savings, and $19 million in quantifiable increased PTCs from owned resources (Rock Creek I and Rock Creek II).[61]

Q. Does PacifiCorp expect NPC benefits to continue in 2027?

A. Yes. It is estimated that NPC would increase on a total company basis by $117.5 million in 2027 without Gateway South. As discussed in the testimony of PacifiCorp

[61] Exhibit PAC/205—Mitchell 2026 TAM Testimony, at 37-38.

witness Isaiah Zacharia in the company's 2027 TAM, this includes a $91.2 million increase in NPC, and $26.3 million decrease in PTCs.[62] The increase in NPC is driven by more constrained wind generation, resulting in decreased market sales and increased market purchases and thermal generation fuel costs.

Q. Is the forecasted $117.5 million increase in NPC conservative?

A. Yes. This analysis assumes that the 1,361 MW of new wind resources that were enabled by Gateway South would still be able to provide NPC benefits. Yet as discussed at length in several proceedings, without Gateway South, these wind resources would not be able to interconnect and deliver energy to load. Accordingly, if Gateway South, and the 1,361 MW of new wind resources the transmission line enabled were removed from service, PacifiCorp would expect NPC to increase far more than $117.5 million.

Q. Based on the information PacifiCorp knew when it decided to proceed with Gateway South, would Oregon customers have benefited from incremental PTCs if PacifiCorp delayed moving forward with the line?

A. No. It is important to stress that PacifiCorp's decision to move forward with Gateway South in June 2022, predated passage of the Inflation Reduction Act in August 2022. Based on PacifiCorp's then-known and knowable information regarding PTC eligibility, if PacifiCorp decided to delay construction of Gateway South by even one year, all the wind resources that depended on Gateway South to come online would have been ineligible for federal PTCs. This would have significantly reduced the value provided by these resources.

[62] Exhibit PAC/206—Zacharia 2027 TAM Testimony, at 27.

Q. Will Gateway South provide additional benefits through PacifiCorp's participation in the Extended Day Ahead Market (EDAM)?

A. Yes. Using comprehensive modeling, PacifiCorp's customers would see $359 million per year in net cost savings by 2032 through participation in EDAM.[63] These estimated benefits are derived mainly from reduced production costs and EDAM congestion and transfer revenues paid to PacifiCorp once they participate in the market.[64] Those benefits rely on the entirety of PacifiCorp's transmission footprint, including Gateway South, by allowing the market to take advantage of the differences in the generation mix across regions, letting it deliver lower cost power to loads and make advantageous trades between market members that reduce costs.

Specific to Gateway South, lower-cost wind resources in southeastern Wyoming and solar resources in Utah will both be able to flow over Gateway South and provide cost-effective generation in EDAM for both PacifiCorp customers and to the market as a whole, giving PacifiCorp the opportunity to make advantageous transactions in the market to reduce costs and local generation curtailments.

Q. Will Oregon customers receive additional NPC benefits from Gateway South-enabled RECs?

A. Yes. The Commission recently approved PacifiCorp's request to sell excess Oregon-allocated RECs, and return 90 percent of the net proceeds from these sales to Oregon retail customers each year.[65] To the extent that incremental RECs from wind

[63] *E.g.*, Exhibit PAC/205, at 25; Confidential Exhibit PAC/207—Brattle EDAM Benefits Study.
[64] *Id.*
[65] *In re PacifiCorp's Request to Sell RECs*, Docket No. UE 467, Advice No. 26-008.

resources enabled by Gateway South result in excess Oregon-allocated RECs, customers would receive 90 percent of the net proceeds from these sales.

iii. HB 2021 and RPS Benefits

Q. Does Gateway South provide HB 2021 or RPS benefits?

A. Yes. Gateway South is important for PacifiCorp's compliance with HB 2021 greenhouse gas emissions reductions requirements and contributes toward meeting the Oregon RPS.

Q. How does Gateway South support PacifiCorp's progress toward compliance with HB 2021?

A. PacifiCorp estimates that Gateway South will enable the generation of approximately 1.5 million MWh of Oregon-allocated wind generation each year, as indicated by PacifiCorp witness Mitchell's analysis presented in the company's 2026 TAM.[66] When PacifiCorp reports its annual greenhouse gas emissions for 2026 to the DEQ, this additional wind generation will substantially decrease PacifiCorp's emissions by reducing reliance on other emitting generation resources or unspecified market purchases. Assuming, even conservatively, that the entirety of the generation enabled by Gateway South was replaced with unspecified market purchases (and not some combination of unspecified purchases, natural gas generation, and coal generation), PacifiCorp's greenhouse gas emissions are substantially reduced.

For example, unspecified market purchases have a 0.428 metric tons of carbon dioxide equivalent per megawatt-hour (MT CO2e/MWh) emissions factor.[67]

[66] *E.g.*, Exhibit PAC/205, at 39, "Confidential Table: Company-Owned Wind Projects Generation and PTC Data.".
[67] OAR 340-215-0120(2)(a).

Multiplying this unspecified emissions factor by the anticipated 1.5 million MWh of Oregon-allocated wind generation each year results in an estimated 642,000 of avoided MT CO2e.[68] This represents an 8.39 percent reduction in PacifiCorp's greenhouse gas emissions from its 2023 levels each year,[69] and nearly 11 percent of the progress necessary to reach HB 2021 compliance obligations in 2030.[70]

Q. Is this emissions reduction benefit associated with Gateway South conservative?

A. Yes. Oregon's unspecified market purchase emissions factor is significantly lower than the average emissions factor for PacifiCorp's existing natural gas fleet that would likely otherwise serve Oregon customers. For example, PacifiCorp's natural gas fleet sums to 3,852 MW of capacity across four states.[71] The DEQ has created facility-specific emissions factors for each of these natural gas resources.[72] The simple average of each of the emissions factors included in the DEQ's workbook is 0.9974 MT CO2e/MWh.[73] The facility-specific emissions factors for PacifiCorp's coal resources, which could also be used to serve Oregon load in some hours if the wind resources enabled by Gateway South were not procured, would be even higher.

Multiplying the higher natural gas emissions factor by the anticipated 1.5 million MWh of Oregon-allocated wind generation enabled by Gateway South results in an estimated 1,496,100 of avoided MT CO2e each year. This equates to a

[68] Actual emissions will be reported to the DEQ in future emissions reports, and available in subsequent PacifiCorp Clean Energy Plans.
[69] PacifiCorp reported actual emissions to the Oregon DEQ of 7,653,943 MT/CO2e in 2023.
[70] The Oregon DEQ defines PacifiCorp's 2030 obligation as an 80 percent reduction in emissions from the baseline, which amounts to only 1,798,890 MT/CO2e emitted in 2030.
[71] *E.g.*, PacifiCorp's 2025 IRP, Table 6.3 (available here: haa335779026.pdf).
[72] *E.g.* "DEQ assigned emission factors for use in the 2025 CEP," Greenhouse Gas Emission Factors for HB 2021 Electricity Sector Emission Projections Excel Workbook (available here: https://www.oregon.gov/deq/ghgp/Pages/Clean-Energy-Targets.aspx) (link to excel workbook here: https://www.oregon.gov/deq/ghgp/Documents/HB2021-EmissionFactors.xlsx).
[73] *Id.*

19.55 percent reduction in PacifiCorp's greenhouse gas emissions from 2023 levels each year, and over 25 percent of the progress necessary to reach HB 2021 compliance obligations in 2030.

Together, Gateway South will reduce PacifiCorp's greenhouse gas emissions by an estimated 8.39 to 19.55 percent from 2023 levels. These avoided emissions are the single largest reduction in PacifiCorp's Oregon-allocated greenhouse gas emissions since the company began reporting emissions to DEQ. These emissions will be avoided each year that the resources interconnected to Gateway South maintain operation and will materially contribute to PacifiCorp's ability to comply with HB 2021.

Q. How does Gateway South impact PacifiCorp's RPS compliance obligation?

A. PacifiCorp anticipates that Gateway South will enable the generation of 1.5 million Oregon-allocated RECs each year (conservatively, assuming no new renewable generation enabled by Gateway South is added in the future). This volume of RECs amounts to approximately 30 percent of PacifiCorp's 2030 RPS requirement, based on the most recent forecast that show an RPS requirement of 4,993,038 MWh RECs.[74]

iv. Increased Resource Adequacy, Interconnection Capacity, and Reliability Benefits

Q. Does Gateway South provide increased resource adequacy value?

A. Gateway South provides critical resource adequacy benefits at a time when the region is experiencing supply shortages. For example, PacifiCorp's regional transmission

[74] *E.g.*, ORS 469A.052(1)(f) (requiring a 35 percent clean energy standard by 2030), calculated based on most recent Oregon retail sales forecast included in PacifiCorp's 2025 Integrated Resource Plan.

system interconnects diverse generation resources, such as solar from Nevada or Utah, wind from Wyoming, and hydro power from the Pacific Northwest. It allows PacifiCorp to sell power, such as during peak hydro generation periods, to other regions and to import renewable resources to the Pacific Northwest during periods of low hydro production.[75] This ability to shift clean resources across its system reduces the need for PacifiCorp to rely on thermal generation, saving its customers fuel costs, emissions costs, and other variable generation costs. Gateway South allows PacifiCorp to produce low-cost wind energy from some of the most valuable wind locations in the West, and deliver that power to customers across PacifiCorp's service territory.

The Commission recently recognized these benefits, when informing the Oregon Governor that addressing customer rate pressure "requires, in many cases, investing in the systems we depend on to mitigate future rate impacts" and postponing investments in transmission and generation "exposes customers to very high market prices, coal and natural gas price volatility, and reliability risks."[76] Staff also specifically acknowledged these resource adequacy benefits in the 2020 All Source RFP, noting back in 2021 that delaying Gateway South would create a "substantial reliability risk associated with allowing a large short capacity position in 2025."[77]

[75] By operating its two BAAs as a collective transmission system, the Company can use resources that are geographically remote to meet system requirements.
[76] Letter from Oregon Public Utility Commission to Tina Kotek, Governor of the State of Oregon, at 2 (Aug. 1, 2025).
[77] *E.g.*, *In re PacifiCorp's 2020AS RFP*, Docket No. UM 2059, Staff Report, at 8 (Oct. 6, 2021) (available here: um2059hau143410.pdf).

Q. Does Gateway South provide additional interconnection capacity?

A. Yes. Gateway South enables more than 2 GW of incremental interconnection capacity. Gateway South also creates additional headroom on PacifiCorp's grid overall, meaning that PacifiCorp can accommodate even more resources in a wind-rich region to meet incremental needs.

Q. Does Gateway South provide additional reliability benefits?

A. Yes. Adding new transmission infrastructure creates additional paths and capacity to transfer energy across the grid, which helps reduce the cost of supplying power during outages on the system, and helps the system avoid service disruptions and return service to customers faster when interruptions would otherwise have occurred due to outages.

As noted in the direct testimony of PacifiCorp witness Richard A. Vail from PacifiCorp's 2026 RAC, Gateway South provides material reliability benefits. Without Gateway South, the addition of the first 320 MW of resources from PacifiCorp's 2020 procurement efforts in eastern Wyoming would have resulted 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 up to Point of Rocks substation in Sweetwater County under certain system outage conditions.[78] These outages, along with thermal overload, would also result in voltages below acceptable limits around the Echo Springs substation in Carbon County.[79] This voltage collapse would violate North American Electric Reliability Corporation and Western Electricity Coordinating Council reliability standards,

[78] *E.g.*, Exhibit PAC/204, at 16.
[79] *Id.*

degrade the reliability of service to other customers, and negatively impact utilities across the Western Interconnection.[80]

v. Test Period Benefits

Q. Focusing specifically on the test year of this case, does Gateway South provide a net benefit to customers?

A. Yes. As detailed in Table 3 below, PacifiCorp's revenue requirement for Gateway South in 2027 is $221.7 million. This includes a $185.1 million return on the investment, and an additional $36.6 million of depreciation expense. Benefits of the Gateway South project in the same period total approximately $262.7 million. This benefit includes the $91.2 million reduction in NPC and $26.3 million of increased PTCs,[81] $126 million in avoided transmission expense and the additional $19.1 million in incremental OATT revenue forecasted from my prior rate case testimony on the net benefits of Gateway South.[82]

Table 3—Total Company 2027 Net Revenue Requirement Benefits of Gateway South[83]

Cost	**$ millions**
Return on Gateway South	185.1
Gateway South Depreciation Expense	36.6
Total Cost	221.7
Benefit	**$ millions**
Reduced Net Power Cost Expense	91.2
Increased Production Tax Credits	26.3
Avoided Transmission	126.0
OATT Revenue	19.1
Total Benefit	262.7
Total Company Net Benefit	**$40.9**

[80] *Id.* at 11.
[81] "GWS 2027 RR Benefits" Workpaper.
[82] *Id.*
[83] Transmission benefits are adjusted from nominal levelized values to annual values, to focus on single year net benefits.

On a total-company basis, the net benefit for Gateway South is $40.9 million in 2027 alone. As presented in the direct testimony of company witness McCoy, Oregon's System Generation factor for 2027 is forecasted to be 27.756 percent. Application of this allocation percentage to total system benefits yields an Oregon-allocated net benefit of approximately $11.4 million.

Q. Is it generally your recommendation that the Commission base its decision to permit the full recovery of the Gateway South project on a single-year cost-benefit analysis?

A. No. PacifiCorp evaluates the costs and benefits that resources or transmission assets provide to customers over the anticipated lifespan of an investment to capture how those benefits change over time. Isolating a single year to determine revenue requirement costs and benefits does not capture these multi-year effects. This single-year exercise also involves post-decision analyses and information, which is inconsistent with Commission precedent that evaluates the information the company knew at the time it decided to move forward with the Gateway South investment. However PacifiCorp provides this analysis to demonstrate that in 2027—the test period of this rate case—Gateway South is expected to provide material benefits to Oregon customers, which is uncommon. It is rare to observe net benefits just three years into a capital-intensive investment having an expected asset life in excess of 60 years.

Q. What conclusions do you believe the Commission should reach based on the net benefits you discuss above?

A. The current and forecasted customer benefits provided by Gateway South support the Commission allowing PacifiCorp to recover its full return on this investment.

C. Extent of Disallowance and Impacts to PacifiCorp's Financial Health

Q. What is the on-going impact of the Commission's Gateway South decision that prevents PacifiCorp from earning its full return?

A. The Commission's decision to limit PacifiCorp's return on its Gateway South investment causes under recovery of $10 million per year, beginning January 2025.

Q. Does this under recovery put added strain on PacifiCorp's financial health?

A. Yes. An under recovery of $10 million per year contributes to PacifiCorp's financial challenges. While this fact alone does not suggest the Commission should approve the full cost recovery of PacifiCorp's Gateway South investment in this rate case, the company has provided additional evidence consistent with Commission direction in previous proceedings that further demonstrates Gateway South is providing and will continue to provide substantial benefits to Oregon customers. This evidence provides sufficient support for the Commission to allow PacifiCorp to earn its full return on its investment, which will also bolster the company's financial position.

Q. Is there anything remaining that you would like the Commission to consider when determining whether to authorize PacifiCorp's full return on Gateway South?

A. Yes. Since the Commission's first substantive review of Gateway South in 2020, the Commission has expressed concern with PacifiCorp's decision to move forward with

the transmission line when it did.[84] The Commission reaffirmed this concern when it found PacifiCorp imprudent for building Gateway South "sooner rather than later" in 2024.[85]

Gateway South has been in service for over a year. The line will be online for over two years by the time the Commission reaches a decision on Gateway South in this proceeding. If 2024 was too soon, PacifiCorp respectfully requests the Commission find that limiting the return on Gateway South for over two years, which will result in an under recovery of over $20 million, is a sufficient disallowance that has adequately addressed the Commission's timing concerns.[86]

This is especially the case, as the 2025 One Big Beautiful Bill Act repealed federal tax credits for wind and solar resources going forward,[87] eliminating all or most PTC benefits for wind and solar resources that Oregon customers could receive if PacifiCorp had waited until 2027 to bring Gateway South online.

V. RECOMMENDATION

Q. What do you recommend?

A. I recommend that the Commission approve PacifiCorp's proposed rate request, including interim rates and the treatment of the Service Area Transfer. I also recommend that the Commission approve in rates PacifiCorp's full return on Gateway South.

[84] *In re PacifiCorp's 2019 IRP*, Docket No. LC 70, Order No. 20-186, at 21 (Jun. 8, 2020) ("For a major expenditure like Gateway south that has moved forward in time," the Commission noted, it "will examine the near-term customer costs" in subsequent RFPs.").
[85] Docket No. UE 433, Order No. 24-447, at 42 (Dec. 19, 2024) (the Commission has been concerned that PacifiCorp "failed to provide sufficient analysis to justify its decision to construct the line sooner rather than later.").
[86] *Id.*
[87] H.R.1 – 2025 Reconciliation Act, Pub. Law No. 119-21 (Jul. 04, 2025).

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 470
Exhibit PAC/201
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Rick T. Link

Link 2025 Rate Case Direct Testimony

May 2026

Docket No. UE 433
Exhibit PAC/800
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Rick T. Link

February 2024

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ATTACHED EXHIBITS

Exhibit PAC/801—Transmission Projects Analysis

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Senior Vice President, Resource Planning, Procurement and Optimization.

Q. Please describe the responsibilities of your current position.

A. I am responsible for PacifiCorp's energy supply management and resource planning and procurement functions, which includes the integrated resource plan (IRP), structured commercial business and valuation activities, and long-term load forecasts. Most relevant to this docket, I am responsible for the economic analysis used to screen system resource investments and conducting competitive request for proposal (RFP) processes, consistent with applicable state procurement rules and guidelines.

Q. Briefly describe your education and professional experience.

A. I joined PacifiCorp in December 2003 and assumed the responsibilities of my current position in September 2021. I have held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities and developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I have been heavily involved in developing PacifiCorp's IRPs since 2013; have been directly involved in several resource RFP processes; and performed economic analysis supporting a range of resource and transmission investment opportunities. Before joining PacifiCorp, I was

an energy and environmental economics consultant with ICF Consulting (now ICF International) from 1999 to 2003, where I performed electric-sector financial modeling of environmental policies and resource investment opportunities for utility clients. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Master of Environmental Management from Duke University in 1999.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in proceedings before the Public Utility Commission of Oregon (Commission), the California Public Utilities Commission, the Idaho Public Utilities Commission, the Utah Public Service Commission (Utah Commission), the Washington Utilities and Transportation Commission , and the Wyoming Public Service Commission.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. I provide economic analysis that supports PacifiCorp's decision to build two transmission projects, including: (1) Gateway South, a 414-mile, 500-kilovolt (kV) overhead transmission line between the Aeolus Substation, near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah; and (2) Gateway West Segment D.1, a 59-mile, 230-kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming and the accompanying ancillary facilities (collectively, the Transmission Projects).

I also summarize PacifiCorp's assessment of the projects from the 2021 IRP and 2021 IRP update, provide background on PacifiCorp's 2020 All-Source Request

for Proposal (2020AS RFP) to solicit new resources, including those enabled by the Transmission Projects, and discuss customer benefits that result from the projects.

For details regarding Gateway South and Gateway West, please refer to the direct testimony of Company witness Richard A. Vail.

Q. Please summarize your testimony for the Transmission Projects.

A. The 2021 IRP confirmed that the Transmission Projects remain a key transmission investment that will enable the procurement of low-cost wind facilities to reliably meet the Company's need for additional resources. These resources are expected to produce significant customer benefits. This includes ensuring that all new wind resources from the 2020AS RFP that depend on the Transmission Projects: (1) qualify for 110 percent of available federal production tax credits (PTC), further reducing the cost of these resources (that already have no fuel costs or emissions) relative to other resource options; and (2) generate renewable-energy certificates (RECs) that can be used to offset revenue requirements where appropriate.

As discussed by Company witness Vail, the Transmission Projects will also provide critical voltage support to the Wyoming transmission network, improve overall reliability of the transmission system, and enhance PacifiCorp's ability to comply with mandated reliability and performance standards. Most importantly, the Transmission Projects ensure the Company will meet its obligations to reliably accommodate nearly 2,500 megawatts (MW) of interconnection and transmission service requests, including 13 executed interconnection service and transmission service agreements for over 1,600 MW of new wind resources. This includes 500 MW of firm point-to-point (PTP) transmission service to a third-party

transmission customer under the Federal Energy Regulatory Commission's (FERC) jurisdiction. Moreover, the Transmission Projects create additional opportunity to increase transfer capability with the construction of additional segments of the Energy Gateway project.

Q. Please summarize your economic analysis of the Transmission Projects.

A. My economic analysis demonstrates that the Transmission Projects are necessary and in the public interest. In my analyses, I reviewed the change in revenue requirement due to the Transmission Projects, and associated resources that are dependent upon the Transmission Projects, using the Company's IRP modeling tool across five different scenarios that pair varying natural gas price assumptions with varying carbon dioxide (CO_2) policy assumptions (price-policy scenarios). For each price-policy scenario, I calculated the change in system revenue requirement between cases with and without the Transmission Projects through 2040, where capital revenue requirement is levelized. The price-policy scenarios include:

- Medium natural gas prices paired with medium CO_2 prices (MM);
- Medium natural gas prices without a CO_2 price (MN);
- High natural gas prices paired with high CO_2 prices (HH);
- Low natural gas prices without a CO_2 price (LN); and
- The Social Cost of Greenhouse Gas (SCGHG).

These analyses confirm that the Transmission Projects are expected to generate customer benefits. Under the MM price-policy scenario, the present-value revenue requirement differential (PVRR(d)) customer benefit when using the most conservative assumptions for unavoidable transmission is $128 million and the risk-

adjusted PVRR(d) benefits are $260 million. When assuming the cost of the Transmission Projects are unavoidable, the PVRR(d) under the MM price-policy scenario yields a $610 million customer benefit and a risk-adjusted benefit of $742 million. Conservatively, these benefits do not assign any value to the RECs that will be generated by new resources made available due to the Transmission Projects. The risk-adjusted results indicate that the Transmission Projects add significant risk mitigation benefits associated with volatility in market prices, loads, hydroelectric generation, and unplanned outages.

Q. Did you develop an additional calculation to measure how changes in cost might influence customer benefits?

A. Yes. I produced a calculation to determine how changes in resource and transmission cost assumptions would impact customer benefits. My review of resource costs show that assumed initial capital costs would need to increase by 32 percent to erode the customer benefits from the MM price-policy scenario. Similarly, the cost of the Transmission Projects would need to increase by 50 percent to erode the benefits from the MM price-policy scenario. These results show that the projected customer benefits are robust, and that they persist even if the resource costs and transmission costs far exceed the estimates that were available when we committed to move forward with the Transmission Projects.

Q. Did you continue to review the economic analysis after the Company began construction of the Transmission Projects?

A. Yes. I revisited the economic analysis as we were finalizing contracts for the wind resources dependent upon the Transmission Projects. This update accounted for,

among other things, higher costs, higher PTC values associated with the passage of the Inflation Reduction Act (IRA), and the potential impacts of the Ozone Transport Rule (OTR). This review showed risk-adjusted customer benefits totaling $247 million in the MM price-policy scenario.

Q. Do you believe your testimony supports the prudency of the Company's investments for both Transmission Projects?

A. Yes.

III. GATEWAY SOUTH AND GATEWAY WEST SEGMENT D.1

A. Need

Q. Did the 2021 IRP identify the need for additional resources to serve PacifiCorp's customers?

A. Yes. The primary focus of the 2021 IRP is to forecast the need for resources and then evaluate different ways to meet that need over time. In the 2021 IRP, the assessment of resource need is presented in Volume I, Chapter 6. The load-and-resource balance shows that PacifiCorp has a capacity deficit in all years of the planning horizon—starting at 1,071 MW in 2021, and increasing to over 6,600 MW by 2040.[1] In 2025, the first full year that the Transmission Projects will be online, the resource need is 1,627 MW. Consistent with prior IRPs, all resource portfolios produced in the 2021 IRP that were considered as candidates for the preferred portfolio contain new supply-side, demand-side, and market resources to fill this need.

This need has continued to increase due to increases in forecasted load. The 2021 IRP Update shows a resource need in all years of the planning horizon—starting

[1] *See* PacifiCorp 2021 Integrated Resource Plan, Vol. I, Table 6.12.

at 1,584 MW in 2022 and increasing to 6,755 MW in 2040.[2] In 2025, the first full year that the Transmission Projects will be online, the resource need is 1,867 MW, an increase of 240 MW or approximately 15 percent from the 2021 IRP. The higher load reflected in the 2021 IRP Update approaches the level analyzed in the high-load sensitivity conducted in the 2021 IRP.[3]

Since the Company initiated construction of the Transmission Projects, national tariff policies, global supply-chain issues, and inflationary pressures eliminated some bids on the 2020AS RFP final shortlist. Consequently, PacifiCorp's procurement was reduced by 902 MW of solar resources and 497 MW of battery storage resources. Additional resources are needed to reduce PacifiCorp's reliance on the market.

Q. Why is it important to reduce PacifiCorp's reliance on market purchases?

A. There is a strong consensus that the western United States will face an increasing capacity deficit in the near future.[4] For example, in December 2020, the Western Electricity Coordinating Council (WECC) issued its Western Assessment of Resource Adequacy Report (WARA).[5] The WARA was developed based on data collected from balancing authorities describing their own demand and supply projections over the next 10 years. The WARA evaluated resource adequacy among six subregions under two scenarios—one with and without imports to the subregion. PacifiCorp serves load in three of these subregions—Northwest Power Pool Northwest (NWPP-

[2] *Id.* at Table 4.2.
[3] *Id.* at 2.
[4] *Id.* at Vol. I, Ch. 5.
[5] *The Western Assessment of Resource Adequacy Report*, Western Electricity Coordinating Council (Dec. 18, 2020) (https://www.wecc.org/Administrative/Western%20Assessment%20of%20Resource%20Adequacy%20Report%2020201218.pdf).

NW), Northwest Power Pool Northeast (NWPP-NE), and Northwest Power Pool Central (NWPP-C). For each of these scenarios, the WARA considered variations of supply. The most conservative assumes availability of only existing resources, and the most liberal includes availability of new resources under construction, those expected to come online, and those under development. The study found that for each of the three subregions in which PacifiCorp serves load, imports are needed to meet a one-day in 10-year planning threshold. The WARA shows that the NWPP-NW subregion would fall short of the planning threshold in 194 hours (under the most liberal supply case) to 208 hours (assuming availability of only existing resources) without imports. In the NWPP-NE and NWPP-C subregions, the study found that planning threshold is not met in 4,200 hours without imports.

These findings highlight that there are real reliability risks associated with relying on supply being available in the market to meet projected load obligations. In addition, WECC's 2021 WARA issued December 2021 further concludes that not only are resource adequacy risks to reliability likely to increase over the next 10 years, it recommends entities take immediate action to mitigate near-term risks and prevent long-term risks. The 2021 WARA projects that "by 2025, each subregion, and the interconnection, will be unable to meet the 99.98%-one-day-in-ten-year-reliability threshold."[6]

[6] *2021 Western Assessment of Resource Adequacy Report*, Western Electricity Coordinating Council (Dec. 17, 2021) (https://www.wecc.org/Administrative/WARA%202021.pdf).

Q. Are there any other third-party studies confirming the resource adequacy concerns in the west?

A. Yes. In December 2020, the North American Electric Reliability Corporation (NERC) issued its Long-Term Resource Adequacy (LTRA) study that included its 10-year WECC region reliability assessment.[7] The NERC LTRA calculates an anticipated resource-based reserve margin to a reference reserve margin to establish one of three risk determinations—adequate (anticipated margin exceeds the reference margin), marginal (anticipated margin is below the reference margin, but new resources under development could cover the shortfall), and inadequate (anticipated reserve margin is below the reference margin and load interruption is likely).

The NERC LTRA shows that the Northwest Power Pool region and Rocky Mountain Reserve Group regions are projected to be inadequate beginning in 2028 even if resources under development come online. Again, these findings highlight the risk of relying on other entities in the region to have excess supply available for the market when PacifiCorp may be required to buy power to serve its customers.

Q. How did the 2021 IRP preferred portfolio address the need for new resources?

A. The 2021 IRP preferred portfolio represented PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period, based on the information available at the time the plan was developed. Using a range of cost and risk metrics to evaluate numerous resource portfolios, PacifiCorp selected a preferred portfolio that reflected a cost-conscious plan with near-term investments in renewable resources that capture tax credits before they expire or decrease, and new

[7] *2020 Long-Term Reliability Assessment*, North American Electric Reliability Corporation (Dec. 2020) (https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf).

transmission infrastructure to facilitate the interconnection and delivery of these resources. These new resources and transmission investments are lower cost than other resource and transmission alternatives and are necessary to reliably serve our customers.

Q. Were the Transmission Projects part of the 2021 IRP preferred portfolio?

A. Yes. As described in Volume I, Chapter 4 of the 2021 IRP, the preferred portfolio includes both Gateway South and Gateway West Segment D.1. In the 2021 IRP, the Transmission Projects are assumed to be placed in service by the end of 2024, consistent with current construction timelines discussed by Company witness Vail. The Transmission Projects will enable the addition of new wind facilities that contribute to meeting 1,627 MW of projected resource need beginning 2025.

Q. Did the Commission acknowledge the Transmission Projects in the 2021 IRP?

A. Yes, and the Commission noted that it expected PacifiCorp to provide adequate analyses of the costs and benefits of transmission projects in future proceedings.[8] I believe my testimony provides the appropriate economic analyses to inform the Commission's request on this issue.

Q. Were the Transmission Projects part of the 2021 IRP Update?

A. Yes.[9]

Q. What new transfer capabilities and interconnection capacity do the Transmission Projects add to PacifiCorp's system?

A. The Transmission Projects will increase the transfer capability between the Aeolus

[8] Order No. 22-178 (May 23, 2022).
[9] PacifiCorp's 2021 Integrated Resource Plan Update, Ch. 7, Action Plan Item 3a–3b, at 103–104 (Mar. 31, 2022) (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021_IRP_Update.pdf).

substation in eastern Wyoming and the Clover substation located near Mona, Utah by 1,700 MW, and enable the interconnection of 2,030 MW of new resources in eastern Wyoming.

Q. Please describe key factors supporting the inclusion of the Transmission Projects as prudent investments in this case.

A. The Transmission Projects allow PacifiCorp to implement system improvements, support the full capacity rating of Gateway South and West, and enable the addition of incremental Wyoming renewable resources to support customer needs and deliver value for customers in the most cost-effective way. As discussed by Company witness Vail, the Transmission Projects will also improve overall reliability of the transmission system, and enhance PacifiCorp's ability to comply with mandated reliability and performance standards. Importantly, at the time PacifiCorp committed to move forward with building these new transmission assets, the Transmission Projects would ensure the Company could meet its obligations to reliably accommodate nearly 2,500 MW of interconnection and transmission service requests, including 13 executed interconnection service and transmission service agreements for over 1,600 MW of new wind resources. This included 500 MW of firm PTP transmission service to a third-party transmission customer under the FERC's jurisdiction.

Q. Please describe the reliability benefits of the Transmission Projects.

A The Transmission Projects directly connect eastern Wyoming to central Utah while enhancing reliability throughout PacifiCorp-served regions. Connecting to the Mona/Clover market hub provides additional flexibility in the use of least-cost

resources from eastern Wyoming or southern Utah.

Moreover, allowing additional generation resources to interconnect and serve load will lessen PacifiCorp's reliance on volatile and potentially diminishing market transactions to serve load. Given concerns over regional resource adequacy, reducing reliance on the market ensures a stable and reliable supply of capacity and energy going forward.

In addition, Gateway South improves reliability by relieving the stress on the transmission system in eastern Wyoming and central Utah. Gateway South relieves stress on the underlying 230-kV transmission system in Wyoming, and it unloads the underlying 345-kV transmission system in central Utah, improving reliability in both regions. Essentially, the 500-kV line brings two distant areas closer to each other in a way that improves regional reliability.

Gateway West Segment D.1 creates a new transmission path that allows for additional resource development in the area. The addition of this line improves the reliability of the transmission system during certain identified outage conditions (Dave Johnston to Amasa 230-kV outage or Amasa – Shirley Basin 230-kV outage). Gateway West Segment D.1 is also a prerequisite for interconnecting new resources, including those selected in the 2020AS RFP. Company witness Vail's testimony addresses transmission system reliability and interconnection issues in greater detail.

B. The 2020AS RFP

Q. Please provide an overview of the 2020AS RFP.

A. The 2020AS RFP was issued to identify resources that could meet the Company's projected resource need identified in the 2019 IRP. Based on the cost-and-

performance assumptions for proxy resources in the 2019 IRP, the Company expected that new wind, solar and battery energy storage systems (BESS) were likely to be the most cost-competitive types of resources offered into the 2020AS RFP. However, bidders could offer proposals for other types of resources (*i.e.*, natural gas, pumped storage, *etc.*).

Q. When was the 2020AS RFP issued?

A. After receiving approval from the Utah Commission (docket 20-035-05) and Oregon Commission (docket UM 2059), PacifiCorp issued the 2020AS RFP on July 7, 2020.[10]

Q. What was the market response to the 2020AS RFP?

A. There was a robust market response that resulted in over 28,000 MW of conforming bids, with an additional 12,500 MW of non-confirming bids. Bids for 24 projects totaling over 9,000 MW of resource capacity located in eastern Wyoming were submitted.

Q. How did the Company evaluate submitted bids?

A. The Company created an initial shortlist that was made public on October 29, 2020. This shortlist included 5,453 MW of renewable resource capacity: 2,974 MW of solar or solar with storage (1,130 MW of battery storage), 2,479 MW of wind, and 200 MW of standalone BESS. PacifiCorp then initiated a capacity factor evaluation

[10] In Oregon Administrative Rules 860-89-0010, et seq., the Oregon Commission has established competitive bidding requirements for certain resource acquisitions by Oregon's investor-owned utilities. *In the Matter of the Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources*, Docket No. AR 600, Order No. 18-324, Appendix A (Aug. 30, 2018) (https://apps.puc.state.or.us/orders/2018ords/18-324.pdf). In addition, Utah's Energy Resource Procurement Act requires a competitive solicitation process before the acquisition of renewable resources greater than 300 MW *See* Utah Code Ann. § 54-17-201 *et. seq.*

process (performed by third-party expert WSP Global). The initial shortlist contained a mix of various ownership structures, including proposals for power-purchase agreements (PPAs), build-transfer agreements (BTAs), and battery storage agreements (BSAs).

Q. What resources were selected to the final shortlist?

A. After evaluating a range of potential bid portfolios, and accounting for bid updates from interconnection study results, the final shortlist included: 1,792 MW of new wind capacity (590 MW as BTAs and 1,202 as PPAs); 1,302 MW of solar capacity as PPAs; 697 MW of BESS (497 MW of BESS capacity paired with solar bids, and 200 MW as standalone BESS capacity as a BSA).[11]

Q. Which final shortlist resources depend on the Transmission Projects for interconnection?

A. Six final shortlist resources, representing over 1,600 MW of wind generation, require the Transmission Projects to interconnect to PacifiCorp's transmission system. Table 1 summarizes the wind resources that require the Transmission Projects to achieve interconnection.

[11] The final shortlist originally included an additional solar bid collocated with BESS. Shortly after the bidder was notified its project was on the final shortlist, it withdrew the bid from the 2020AS RFP. This bid is not included in the total capacity.

Table 1. 2020AS RFP Wind Bids Dependent on the Transmission Projects for Interconnection

Project	Bidder	Structure	Capacity (MW)
Cedar Springs IV	NextEra	PPA	350
Boswell Springs	Innergex	PPA	320
Two Rivers	BlueEarth Renewables LLC and Clearway Renew LLC	PPA	280
Anticline	NextEra	PPA	101
Rock Creek I	Invenergy	BTA	190
Rock Creek II	Invenergy	BTA	400

Q. Was the 2020AS RFP overseen by independent evaluators?

A. Yes. Consistent with Utah and Oregon Commissions' requirements, the solicitation process was overseen by two independent evaluators—one retained by PacifiCorp and appointed by the Oregon Commission (PA Consulting Group, Inc.), and one retained by the Utah Commission (Merrimack Energy Group).

Q. What were the independent evaluators' conclusions regarding the 2020AS RFP?

A. Both independent evaluators concluded that the process was fair and transparent, and that the bids selected for the final shortlist were reasonable.

Q. Please describe the Utah independent evaluator's conclusions regarding the 2020AS RFP.

A. In its Shortlist Report, the Utah independent evaluator concluded that the RFP was fair, reasonable, and in the public interest.[12] In particular, the Utah independent evaluator concluded:

- The market response to the RFP was robust and, "Based on the unbelievable response from the market it is safe to say that the solicitation process resulted in a very competitive process with many more proposals generally submitted than the expected requirements by bubble identified by PacifiCorp."[13]

[12] *In re Rocky Mountain Power 2020AS RFP Application*, Docket No. 20-035-05 (Utah Public Service Commission; Sept. 2, 2021) (https://psc.utah.gov/2020/01/24/docket-no-20-035-05/).
[13] Utah Independent Evaluator Shortlist Report at 74.

- PacifiCorp engaged the bidders throughout the process in a timely manner to ensure that all bidders were treated fairly.

- All bidders were treated the same, had access to the same information at the same time, and had an equal opportunity to compete.

- PacifiCorp implemented its evaluation and selection process consistent with its proposed evaluation and selection process as outlined in the RFP in a structured and consistent manner designed to result in the selection of a portfolio of projects that would result in a least cost solution.

- PacifiCorp subjected all bidders to the same information requirements and conducted a consistent evaluation process with all proposals treated equally in terms of the evaluation methodology and information required of each bidder.

- The selection process was unbiased with respect to ownership structures, i.e., the process did not unreasonably favor bids that resulted in a utility-owned resource.

- The selected bids resulted in lower system cost than a case where no bids were selected and maximized customer benefits while managing risk.

Q. Please describe the Oregon independent evaluator's conclusions regarding the 2020AS RFP.

A. In its Closing Report, the Oregon independent evaluator concluded that the final shortlist reflected a diverse portfolio of competitive resources that achieves the resource adequacy and least cost goals set forth in PacifiCorp's IRP.[14] This was based on the following conclusions:

- PacifiCorp's procurement process, scoring methodology and results were fair and free of bias across all bids and bidders.

- PacifiCorp applied the rules of the 2020AS RFP in an unbiased manner, communicated transparently with the independent evaluators regarding their modelling processes and with stakeholders regarding their decisions.

- PacifiCorp's bid price scores were on average consistent with the independent evaluator's independent scoring methodology.

[14] *In re PacifiCorp's 2020AS RFP Application*, Docket No. UM 2059 (Oregon Commission; Jun. 15, 2021) (https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=22320).

- PacifiCorp's utilization of an outside consultant, WSP Global, to evaluate wind, solar, and battery storage benefitted stakeholders.

- The final shortlist was reasonably aligned with the 2019 IRP preferred portfolio.

Q. Did the Oregon Commission acknowledge the shortlist?

A. Yes.[15] Acknowledgement means that the Oregon Commission found that the "final shortlist appears reasonable at the time of acknowledgment and was determined in a manner consistent with [Oregon's] competitive bidding rules."[16] The Oregon Commission noted that the final shortlist "is a reasonable capacity and energy blend, with diversity in contract structures (and therefore rate impact profiles), technology types, and geography."[17]

C. Price-Policy Assumptions

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analysis.

A. The economic analysis of the Transmission Projects includes five price-policy scenarios—MM, MN, HH, LN, and SCGHG. These assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect net-power cost (NPC) benefits, non-NPC variable-cost benefits, and system fixed-cost benefits associated with the Transmission Projects. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. Table 2

[15] Docket No. UM 2059, Order No. 21-437 (Nov. 24, 2021) (https://apps.puc.state.or.us/orders/2021ords/21-437.pdf).
[16] *Id.* at 12.
[17] *Id.* at 13.

summarizes the price-policy scenarios used to analyze the Transmission Projects.

Table 2. Price-Policy Scenario Assumption Overview

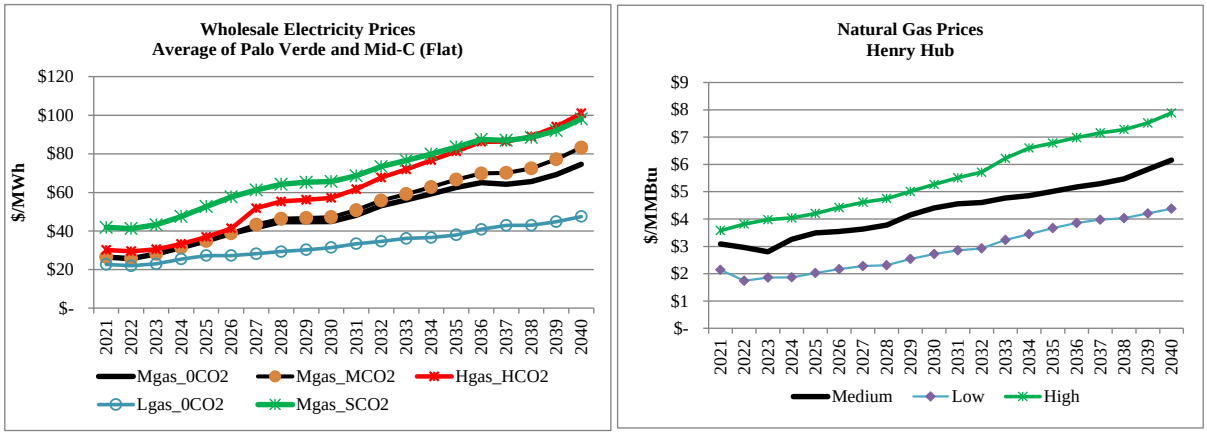
Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)	CO_2 Price Description
MM	$4.44	$9.93/ton starting 2025 rising to $57.94/ton in 2040
MN	$4.44	None
HH	$5.64	$22.57/ton starting 2025 rising to $102.48/ton in 2040
LN	$2.94	None
SCGHG	$4.44	$74.10/ton starting 2021 rising to $150.38/ton in 2040
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. Please describe the natural-gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's official forward price curve (OFPC) dated March 31, 2021, which was the most current OFPC available when PacifiCorp prepared its modeling inputs for the 2021 IRP. The first 36 months of the OFPC reflect market forwards at the close of a given trading day (March 31, 2021, in this case). As such, these 36 months are market forwards as of March 2021. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party, multi-client "off-the-shelf" price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAXMP4 (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast

for market hubs in which PacifiCorp participates. Figure 1 shows Henry Hub natural-gas price assumptions for the medium, high, and low natural gas price scenarios.

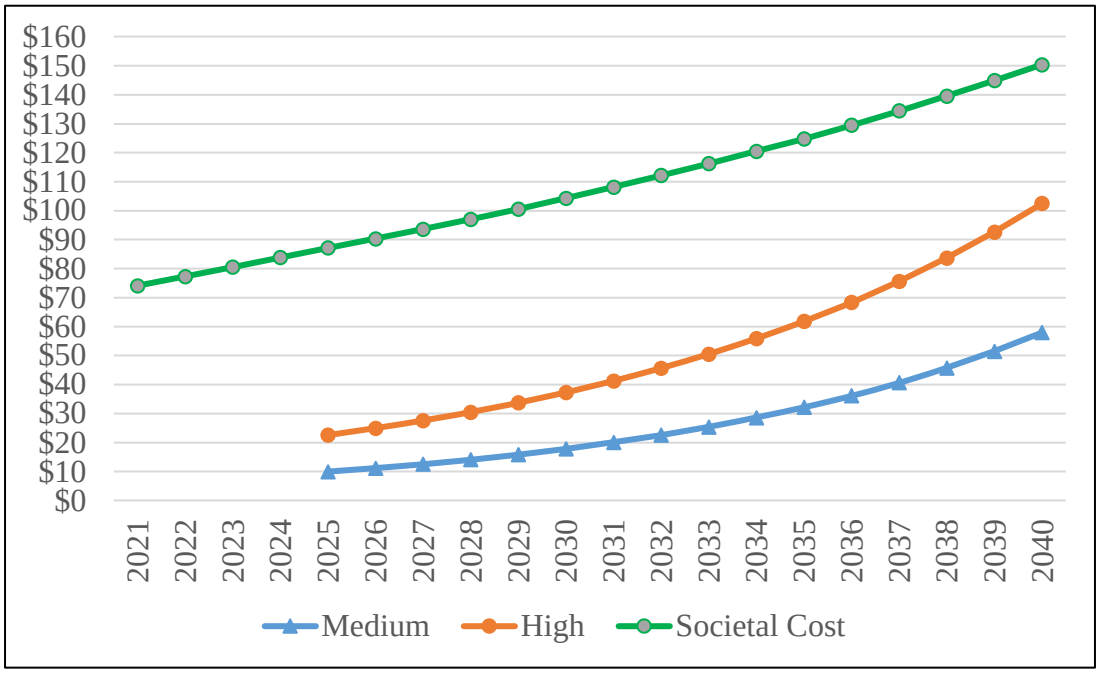
Figure 1. Natural Gas Price Assumptions



Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used four different CO_2 price scenarios in the 2021 IRP—zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases. The medium and high scenario are derived from expert third-party, multi-client "off-the-shelf" subscription services. Both scenarios apply a CO_2 price beginning 2025. PacifiCorp also incorporated the social cost of greenhouse gas, which is assumed to start in 2021. The social cost of greenhouse gases is applied such that the price for the social cost of greenhouse gas is reflected in market prices and dispatch costs for the purposes of developing each portfolio (*i.e.*, incorporated into capacity expansion optimization modeling). Figure 2 shows the three non-zero CO_2 price assumptions used to analyze the Transmission Projects.

Figure 2. CO_2 Price Assumptions



Q. How did PacifiCorp pair the natural gas and CO_2 price assumptions for purposes of its analysis of the Transmission Projects?

A. Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2024 before transitioning to a fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards because these scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party, multi-client "off-the-shelf" subscription services.

Q. Does including potential future CO_2 costs reflect prudent utility planning?

A. Yes. The Company's price-policy scenarios include varying levels of assumed CO_2 costs to reflect the fact it is more likely than not that some policy will exist that will

drive reduced emissions over the life of the Transmission Projects. When determining CO_2 costs used for planning purposes, the Company strives to ensure that it is not an outlier as discussed above, and the medium price is within a reasonable range used by the industry to assess risk and conduct prudent resource planning.

Q. Are the modeled CO_2 costs intended to represent a literal carbon tax?

A. No. The modeled CO_2 costs are not intended to explicitly account for a future tax on CO_2 emissions. Rather, these costs capture the effect of policies incentivizing reduced emissions through benefits or imposing costs through penalties or other costs resulting from market dynamics driving the need for zero-emission resources or customer preferences.

D. Modeling Methodology

Q. Please describe the modeling methodology PacifiCorp used in its analysis of the Transmission Projects.

A. PacifiCorp calculated a system present-value revenue requirement (PVRR) by identifying least-cost resource portfolios and dispatching system resources through 2040, which aligns with the 20-year forecast period used in the 2021 IRP. Net customer benefits are calculated as the PVRR(d) between two simulations of PacifiCorp's system. One simulation includes the Transmission Projects, and the other simulation excludes them. In addition, because wind bids selected from the 2020AS RFP located in eastern Wyoming cannot interconnect without the Transmission Projects, these wind resources are also eliminated from the simulation without the Transmission Projects. When the two simulations are compared, changes

to system costs are attributable to the Transmission Projects and associated wind resources from the 2020AS RFP final shortlist.

Customers are expected to realize benefits when the system PVRR from the simulation with the Transmission Projects is lower than the system PVRR without the Transmission Projects. Conversely, customers would experience increased costs if the system PVRR with the Transmission Projects were higher than the system PVRR without the Transmission Projects.

Q. Are there any other costs that differ between the simulations with and without the Transmission Projects?

A. Yes. The simulation that excludes the Transmission Projects includes the cost of transmission upgrades necessary to accommodate PacifiCorp's obligation to provide 500 MW of firm PTP transmission service to a third-party customer. As explained in more detail by Company witness Vail, these transmission upgrade costs were included because, even conservatively ignoring all the executed interconnection service and transmission service contracts listing the Transmission Projects as prerequisites and focusing solely on the upgrades required to provide service under one transmission service contract, PacifiCorp assumed it would need to construct a 230-kV line by the end of 2024 at an estimated cost of approximately $1.4 billion.

Further, this $1.4 billion cost is the minimum cost for the alternative considering that it includes only the upgrades required to provide service under a single transmission service contract. Additional costs would be incurred to provide service under all interconnection service contracts listing the Transmission Projects as prerequisites. To provide service under all these contracts, it is likely the alternative

would be to construct the Transmission Projects, which means that construction of these transmission investments are unavoidable given PacifiCorp's federal open access transmission tariff obligations to grant interconnection and transmission service requests.

Q. Please describe the modeling tool used to create the economic analysis of the Transmission Projects.

A. PacifiCorp uses the PLEXOS modeling system. The PLEXOS modeling system provides three platforms of the PLEXOS tool (referred to as Long-term (LT), Medium-term (MT) and Short-term (ST)), which work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon. The PLEXOS tool also allows for improved endogenous modeling of resource options simultaneously, greatly reducing the volume of individual portfolios needed to evaluate impacts of varying resource decisions.

Q. Please describe how PacifiCorp used the LT model.

A. PacifiCorp used the LT model to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and amount of new resources that could be pursued to serve customers over the next 20 years. Portfolios from the LT model are informed by an hourly review of reliability based on ST model simulations (described below). This ensures that each portfolio meets minimum reliability criteria in all hours.

Q. Please describe how PacifiCorp used the MT model.

A. PacifiCorp used the MT model to perform stochastic risk analysis of the portfolios. Each portfolio was evaluated for cost and risk among five price-policy scenarios (MM, MN, HH, LN, and SCGHG). A primary function of the MT model is to calculate an optimized risk-adjustment, representing the relative risk of a portfolio under unfavorable stochastic conditions for that portfolio.

Q. Please describe how PacifiCorp used the ST model.

A. PacifiCorp used to ST model to evaluate each portfolio to establish system costs over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a PVRR, which serves as the basis for selecting least-cost, least-risk portfolios. As noted above, ST model simulations were also used to identify the potential need for resources in the portfolio to maintain system reliability.

Q. How did each of the three PLEXOS models work together to inform the economic analysis presented here?

A. In the first step, resource portfolios (with and without the Transmission Projects and associated wind resources) were developed using the LT model. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves and regulation reserves plus a minimum capacity reserve margin for each load area represented in the model.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new demand-side management (DSM) alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. Dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

Each portfolio developed by the LT model must have sufficient capacity to be reliable over the IRP's 20-year planning horizon. The resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental DSM resources.

Q. What is the next step in the modeling process?

A. In the second step, the Company conducted a reliability assessment using the ST model. The ST model begins with a portfolio from the LT model that has not yet

benefited from a reliability assessment conducted at an hourly level. The ST model is first run at an hourly level for 20 years to retrieve two critical pieces of data: (1) shortfalls by hour; and (2) the value of every potential resource to the system. This information is then used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. The ST model is then run again with the modified portfolio to calculate an initial PVRR, which is risk-adjusted by outcomes of MT model stochastics that occurs in the third step of the process.

Q. Please describe how the MT model is used to conduct cost and risk analysis.

A. In the third step, the resource portfolios developed by the LT model and adjusted for reliability by the ST model are simulated in the MT model to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. The MT results are used to calculate a risk adjustment, which is combined with ST model system costs to achieve a final risk-adjusted PVRR.

Q. Is the PLEXOS model appropriate for analyzing the customer benefits of the Transmission Projects?

A. Yes. The PLEXOS model is the appropriate modeling tool when evaluating significant capital investments that influence PacifiCorp's resource mix and affect

least-cost dispatch of system resources. The LT model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource and transmission capital projects and is needed to understand how the type, timing, and location of future resources might be affected by the Transmission Projects. The ST and MT models provide additional granularity on how the Transmission Projects are projected to affect system operations while assessing stochastic risks. Together, the LT, MT, and ST models are best suited to perform a benefit analysis for the Transmission Projects that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP and resource procurement activities.

Q. When developing resource portfolios with the PLEXOS model, did you perform a reliability assessment?

A. Yes. As described above, the ST model was used to establish system costs for each portfolio over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes that will reveal whether an initially reliable portfolio selected by the LT model leaves shortfalls at an hourly level, which can then be addressed.

Q. Did PacifiCorp analyze how other assumptions affect its economic analysis of the Transmission Projects?

A. Yes. The economic analysis also included one sensitivity that quantified how changes in new resource capital costs for the two BTA wind projects and capital cost assumptions for the Transmission Projects influenced projected customer benefits.

Q. Company witness Vail's testimony indicates that the Transmission Projects will enable up to 2,030 MW of new resources to interconnect in eastern Wyoming. Why does your analysis only account for 1,640 MW?

A. The economic analysis reasonably accounted for only those wind resources that were selected to the 2020AS RFP final shortlist.

Q. Does PacifiCorp assume that all the up-front capital costs of the Transmission Projects will be paid by its retail customers?

A. No. The cost of the Transmission Projects will be shared between PacifiCorp's retail and wholesale transmission customers. In my analyses, I assumed retail customers would pay 80 percent of the revenue requirement from the up-front capital cost for the Transmission Projects, after accounting for an assumed 20 percent revenue credit from the Company's transmission customers.

E. Price-Policy Scenario Results

Q. Please summarize the PVRR(d) results calculated from the PLEXOS model.

A. Table 3 summarizes the PVRR(d) results for each price-policy scenario.[18]

Table 3. PVRR(d) (Benefit)/Cost of the Transmission Projects ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	($128)	($260)
LN	$755	$670
MN	$393	$289
HH	($932)	($1,100)
SCGHG	($2,568)	($2,819)

[18] Exhibit PAC/801 Transmission Projects Analysis.

As shown above, system costs increase when the Transmission Projects are removed from the portfolio in the MM, HH, and SCGHG price-policy scenarios. Conversely, costs decrease in the LN and MN price-policy scenarios. Without the Transmission Projects, emissions from PacifiCorp's generation resources increase considerably—ranging from 8.4 percent in the MN price-policy scenario to 17.8 percent in the SCGHG price-policy scenario. The LN and MN scenarios unrealistically fail to account for the risk that there will be some form of policy action taken to impute a cost or penalty on greenhouse gas emissions over the planning period. It is also unlikely gas prices will be suppressed for many decades to come, as assumed in the LN price-policy scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of not building the Transmission Projects should policies develop that impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under the HH and SCGHG price-policy scenarios relative to the size of cost reductions in the unlikely LN and MN price-policy scenarios.

Considering that the removal of the Transmission Projects increases system costs among the MM, HH, and SCGHG price-policy scenarios, significantly increases emissions and associated costs and risks, and significantly increases market-reliance risk (discussed further below), this analysis supports the necessity of the Transmission Projects and indicates that they are likely to result in robust customer benefits.

Q. Did you calculate how the PVRR(d) results presented above would change if you assumed the Transmission Projects would be required to provide service under all these interconnection and transmission service contracts?

A. Yes. This would increase the cost of the "alternative" to equal the cost of the Transmission Projects, which represents a $971 million increase in unavoidable capital relative to what is shown in the table above. This translates into $482 million on a PVRR basis. Table 4 shows the PVRR(d) results with this level of unavoidable capital. When this higher cost is applied to the results, the MN price-policy scenario now shows there are significant customer benefits from the Transmission Projects.

Table 4. PVRR(d) (Benefit)/Cost of the Transmission Projects Assuming the Transmission Projects are Unavoidable ($ million)

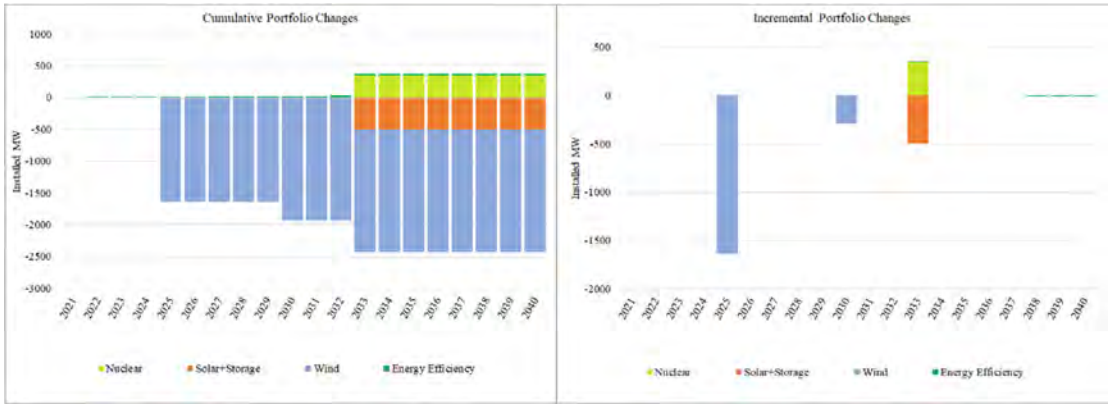
Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	($610)	($742)
LN	$273	$188
MN	($90)	($194)
HH	($1,414)	($1,582)
SCGHG	($3,050)	($3,301)

Q. Please describe the impact of removing the Transmission Projects and associated wind resources from the 2021 IRP's preferred portfolio.

A. Figure 3 shows the cumulative (at left) and incremental (at right) portfolio changes when the Transmission Projects are eliminated under the MM price-policy scenario. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the Transmission Projects are eliminated. Without the Transmission Projects, the 1,640 MW of wind resources selected in the 2020AS RFP are removed from the portfolio in 2024 (shown as a reduction in 2025, the first full

year these resources would be online). An additional 289 MW of wind is eliminated in 2030. In 2034, the absence of the new wind resources triggers the addition of an advanced nuclear plant that displaces solar co-located with storage resources.

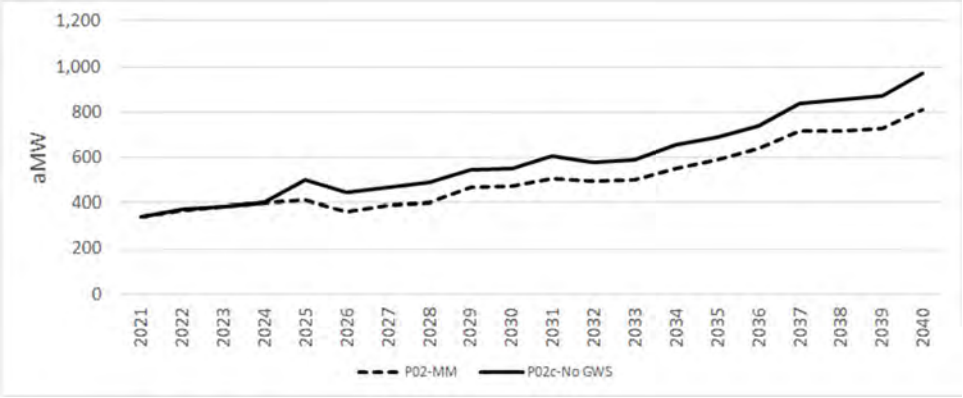
Figure 3. Changes in the Resource Portfolio without the Transmission Projects



Q. Does the removal of the Transmission Projects and associated wind resources increase the Company's reliance on market purchases?

A. Yes. Figure 4 shows how market purchases change when the Transmission Projects are removed from the portfolio under the MM price-policy scenario. With fewer resources, market purchases increase by nearly 20 percent on an annual basis. This creates higher risk as the Company is forced to rely on market purchases at a time when there are increasing resource adequacy concerns throughout the western interconnect. This increased market and reliability risk is not reflected in the PVRR(d) results.

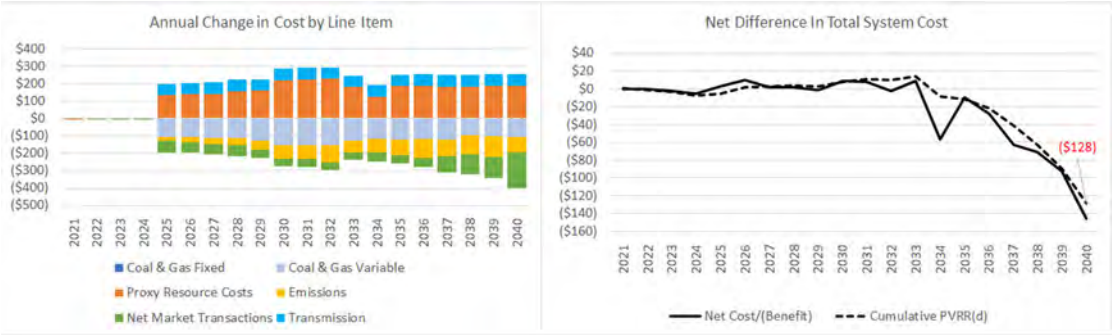
Figure 4. Changes in Market Purchases without the Transmission Projects



Q. How do system costs change with and without the Transmission Projects?

A. Figure 5 summarizes changes in system costs (conservatively assuming the cost for a 230-kV alternative is unavoidable), based on ST model results using MM price-policy assumptions, when the Transmission Projects are eliminated from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without the Transmission Projects is $128 million higher cost than the portfolio with the Transmission Projects. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the Transmission Projects is $260 million higher cost than the portfolio with the Transmission Projects. The risk-adjusted results indicate that the Transmission Projects add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.

Figure 5. Increase/(Decrease) in System Costs when the Transmission Projects are Removed from the Portfolio



Q. Is there incremental customer upside to the PVRR(d) results?

A. Yes. The PVRR(d) results presented in Table 4 do not reflect the potential value of RECs generated by the incremental energy output from the renewable projects enabled by the Transmission Projects. Customer benefits for all price-policy scenarios would improve by approximately $42 million for every dollar assigned to the incremental RECs that will be generated through 2040. Beyond potential REC-revenue benefits, the economic analysis of the Transmission Projects does not reflect the reliability benefits that these investments will provide to the transmission system, which are described by Company witness Vail.

Q. How do the risk-adjusted PVRR(d) results compare to the stochastic-mean PVRR(d) results?

A. The risk-adjusted PVRR(d) results show an increase in the benefits of the Transmission Projects when compared to the reported ST-model PVRR(d) results. This indicates that the Transmission Projects provide stochastic risk benefits by making the system less susceptible to low-probability combinations of load, market price, hydro generation, and thermal outage volatility that can increase system costs.

Q. Have you calculated how changes in the capital cost for the Transmission Projects might affect customer benefits?

A. Yes. A one percent increase in the initial capital costs associated with the Transmission Projects would reduce PVRR benefits by $4.8 million. This estimate conservatively assumes that there is no change in transmission costs that will be avoided with the construction of the Transmission Projects. In the MM price-policy scenario, capital costs for the Transmission Projects would need to increase by 54 percent to eliminate customer benefits on a risk-adjusted basis. This demonstrates that the projected customer benefits are robust to potential variations in capital costs for the Transmission Projects, particularly when considering that the cost estimates used in the economic analysis of the Transmission Projects reflect PacifiCorp's experience with the recent construction of Gateway West Segment D.2 and the associated 230-kV network upgrades reflecting current market conditions.

F. <u>Post-Construction Economic Review</u>

Q. Did you continue to revisit your economic analysis of the Transmission Projects after initiating construction?

A. Yes.

Q. Why did you continue to revisit your economic analysis?

A. After PacifiCorp provided its notice to proceed to begin constructing the Transmission Projects, the Company continued to negotiate contracts for the wind resources that are dependent on the Transmission Projects. During the pendency of those negotiations, there were two significant developments that affected the cost of the wind resources. Considering that the cost of the wind resources affects the

economic analysis of the Transmission Projects, I continued to check that changes to costs did not erode customer benefits.

Q. Please describe the two developments that affected the cost of the wind resources dependent upon the Transmission Projects.

A. First, as the Company finalized contracts with resources selected to the 2020AS RFP final shortlist, national tariff policies, global supply-chain challenges, and inflationary pressures required that bidders secure higher prices than originally offered into the 2020AS RFP. Second, Congress passed the IRA that, among other things, provided an opportunity for the wind projects dependent upon the Transmission Projects to qualify for a 110 percent PTC, which is substantially higher than the 60 percent PTC assumed in my economic analysis that supported the Company's decision to begin constructing the Transmission Projects.

Q. How did you evaluate the impact of these developments on the economic analysis of the Transmission Projects?

A. As the Company finalized the wind resource contracts to capture price changes and new provisions related to the IRA, MM price-policy results were revisited so that we could understand how the economic analysis was being impacted. The updated analysis captured price changes in the contracts and incorporated updated energy values for projected wind energy using more current market price assumptions (*i.e.*, June 2022).

Q. Did your post-construction economic review capture other updates?

A. Yes. Due to the price pressures I discussed above, some of the 2020AS RFP final shortlist bidders were unwilling to offer any form of price update. These projects

were removed from consideration. While this did not include any of the wind projects dependent on the Transmission Projects, the removal of bids increases the overall need for new resources. The updated analysis also included any new contracts that were executed outside of the 2020AS RFP process and incorporated the most current load forecast, which was developed in May 2022. The updated analysis also accounted for the potential impact of the OTR.

Q. What did you find when you prepared this post-construction economic review of the Transmission Projects?

A. This on-going review continued to show that the Transmission Projects are expected to generate customer benefits. 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. This is similar to the comparable risk-adjusted customer benefits totaling $260 million from the economic analysis in place when the Company initiated construction of the Transmission Projects.

IV. CONCLUSION

Q. Please summarize the conclusions of your Gateway South and Gateway West testimony.

A. PacifiCorp's analysis shows that the Transmission Projects are necessary and in the public interest. Under the MM price-policy scenario, the Transmission Projects produce significantly lower total system costs—ranging from $128 to $260 million when using the most conservating assumptions for avoided transmission and ranging from $610 million to $742 million when assuming the Transmission Projects are

unavoidable. The Transmission Projects are also lower risk than alternative scenarios without the resources. Most notably, without the Transmission Projects and accompanying wind resources, the Company is forced to rely heavily on market purchases to serve load, which increases risk related to market volatility and creates reliability concerns given the region's well established resource adequacy concerns. By proactively constructing the Transmission Projects the Company can not only save customers money (as evidenced by the savings in the MM price-policy scenario) but also reduce customer risk, which is a non-quantifiable benefit that strongly favors the Transmission Projects. The updated economic analysis of the Transmission Projects demonstrates that net benefits more than outweigh net project costs.

Q. What do you recommend?

A. As supported by PacifiCorp's economic analysis, I recommend that the Commission determine that Company's decisions to invest in the Transmission Projects are prudent and reasonable.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 470
Exhibit PAC/202
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Rick T. Link

Link 2025 Rate Case Reply Testimony

May 2026

Docket No. UE 433
Exhibit PAC/2500
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

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.

REDACTED
Docket No. UE 470
Exhibit PAC/203
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Rick T. Link

Link 2026 RAC Direct Testimony

May 2026

REDACTED
Docket No. UE 451
Exhibit PAC/300
Witness: Richard T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Richard T. Link

April 2025

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ATTACHED EXHIBITS

Confidential Exhibit PAC/301 – Combined Rock Creek I and II Analyses

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and current position with PacifiCorp d/b/a Pacific Power (PacifiCorp).

A. My name is Richard (Rick) T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Senior Vice President, Resource Planning and Procurement.

Q. Please describe your education and professional experience.

A. I joined PacifiCorp in December 2003 and assumed the responsibilities of my current position in May 2024. I have held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities, developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I have been heavily involved in developing PacifiCorp's integrated resource plans (IRPs) since 2013; have been directly involved in several resource request for proposal (RFP) processes; and performed economic analysis supporting a range of resource and transmission investment opportunities. Before joining PacifiCorp, I was an energy and environmental economics consultant with ICF Consulting (now ICF International) from 1999 to 2003, where I performed electric-sector financial modeling of environmental policies and resource investment opportunities for utility clients. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Master of Environmental Management degree from Duke University in 1999.

Q. Briefly describe the responsibilities of your current position.

A. I am responsible for PacifiCorp's resource planning and procurement functions, which include the IRP, structured commercial business, and valuation activities. Most relevant to this docket, I am responsible for the economic analysis used to screen system resource investments and for conducting competitive resource RFP processes consistent with applicable state procurement rules and guidelines.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in proceedings before the Public Utility Commission of Oregon (Commission), the California Public Utilities Commission, the Idaho Public Utilities Commission, the Utah Public Service Commission, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in this case?

A. Consistent with the Commission's decision from PacifiCorp's latest rate case in docket UE 433, I discuss the actual benefits that Oregon customers are currently receiving from the Gateway South Segment F Aeolus–to–Mona/Clover 500 kilovolt (kV) transmission line (Gateway South). These benefits further support PacifiCorp's decision to move forward with its investments in Gateway South when it did—instead of delaying construction of this transformative asset for several years.

I also provide economic analyses that support PacifiCorp's decisions to acquire the 190 megawatt (MW) Rock Creek I and 400 MW Rock Creek II wind facilities (collectively, the Rock Creek projects), and describe how these projects provide economic benefits supported by Gateway South.

Q. Please provide an overview of your Gateway South testimony.

A. My testimony indicates that while Gateway South has been in service for just over four months, it has already provided Oregon customers with substantial benefits. These include:

- *Reduced wind curtailment*. While [redacted] percent of PacifiCorp's entire Wyoming wind fleet was curtailed in various hours before Gateway South came online, only [redacted] percent has been curtailed after. And these reductions are despite an additional 481.5 MW of Wyoming wind resources coming online after Gateway South became operational, which otherwise would have led to significantly more curtailments.
- *Power cost benefits*. Oregon-allocated net power costs decreased by $63 million for 2025 as a direct result of Gateway South, including $44 million in power cost savings, and $19 million in increased quantifiable production tax credit (PTC) benefits. These PTC benefits are expected to increase as the remaining Gateway South interconnection capacity is filled with additional qualifying resources.
- *House Bill (HB) 2021 Compliance*. Gateway South, and the HB 2021-compliant resources that would otherwise be unable to interconnect with PacifiCorp's system without the transmission line, lead to an 8.4 to 19.6 percent reduction in PacifiCorp's Oregon-allocated greenhouse gas emissions from 2023 levels. This is the single largest reduction in PacifiCorp's Oregon-allocated emissions since the company began reporting emissions to the Oregon Department of Environmental Quality (DEQ).

- *Renewable Portfolio Standard (RPS) Compliance*. Gateway South, and the renewable energy credits (RECs) from wind resources that would otherwise be unable to interconnect with PacifiCorp's system without the transmission line, amount to approximately 30 percent of PacifiCorp's 2030 RPS obligation.

In their testimony, Richard A. Vail and John Tsoukalis also discuss the increased reliability benefits provided by Gateway South specifically, and by increased transmission capacity in general. Considering the totality of testimony provided by PacifiCorp in this proceeding, I recommend the Commission conclude that these benefits support the company earning a full rate of return on Gateway South.

Q. Please provide an overview of your testimony for the Rock Creek I and II wind projects.

A. My economic analyses indicate that the projects will generate significant benefits for Oregon customers. Analysis prepared before passage of the Inflation Reduction Act (IRA) showed risk-adjusted benefits ranging from a present-value revenue requirement differential (PVRR(d)) at a $2 million cost to customers for both projects in the low natural gas, no carbon scenario, to a $163 million benefit in the medium natural gas, medium carbon scenario. After passage of the IRA, these benefits substantially increased, ranging from a risk-adjusted benefit of $151 million to $318 million under the same scenarios. Conservatively, these benefits do not assign any value to the RECs that will be generated by the Rock Creek projects, which can provide additional customer benefits if sold, transferred, or used to comply with relevant state requirements.

III. GATEWAY SOUTH

Q. Please describe the Gateway South transmission line.

A. Gateway South is a 414-mile, 500 kV overhead transmission line between the Aeolus Substation, near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. As discussed by Mr. Vail, this line came online at the end of 2024, and enables the interconnection of up to 2,030 MW of resources in eastern Wyoming. Given the geographic location of Gateway South, and subsequent contracting experiences, PacifiCorp expects that the entirety of this interconnection capacity will be filled with low-cost wind resources.

Q. Has PacifiCorp sought recovery of the costs associated with Gateway South in other states?

A. Yes. Consistent with PacifiCorp's current multi-state cost allocation protocol, Gateway South is a system resource, with a percentage of the costs allocated to retail rates among all of PacifiCorp's jurisdictions. The public service commissions of Utah,[1] Idaho,[2] Wyoming,[3] and Washington[4] have either approved full recovery of Gateway South, or are currently considering PacifiCorp's full cost recovery of these assets.[5]

Q. Has the Commission expressed concerns with PacifiCorp's planned investment in Gateway South?

[1] *In re PacifiCorp's 2024 Utah Rate Case*, Docket No. 24-035-04.
[2] *In re PacifiCorp's 2024 Idaho Rate Case*, Docket No. PAC-E-24-04, Order No. 36452 at 3 (Jan. 31, 2025).
[3] *In re PacifiCorp's 2024 Wyoming Rate Case*, Docket No. 20000-664-EM-24, Record No. 17547, Memorandum Opinion, Findings, and Order Approving Stipulation (Feb. 18, 2025); *In re PacifiCorp's 2023 Wyoming Rate Case*, Docket No. 20000-633-ER-23, Record No. 17252, Memorandum Opinion, Findings, and Order at 47 (Jan. 2, 2024).
[4] *In re PacifiCorp's 2023 Washington Rate Case*, Docket No. UE-230172, Order 08 at 1 (Mar. 19, 2024).
[5] Due to procedural ratemaking details that are not relevant to this proceeding, PacifiCorp has not yet requested recovery of Gateway South from California customers.

A. Yes. The Commission concluded that Gateway South was reasonable to include in its acknowledgement of the 2020 All Source RFP final short list, in part because it would increase "regional electric system reliability, delivery of generation resources, and satisfaction of what may indeed be federal legal obligation."[6] However, the Commission remained concerned about whether PacifiCorp's planned investments in Gateway South were appropriately analyzed.[7]

To address these concerns, the Commission scheduled a workshop and directed PacifiCorp to discuss the federal-state relationships around transmission decisions and obligations, and alternative financing of transmission investments if necessary.[8] The Commission also concluded that, in a future rate proceeding, it would look at typical prudence requirements, as well as "review of federal transmission obligations . . . and actual benefits and costs of the project as built, with the opportunity to look at aspects like HB 2021 compliance, increased reliability, and diversified resources."[9]

Q. Did the Commission raise similar concerns in PacifiCorp's IRP proceedings?

A. Yes. In 2022, while reviewing PacifiCorp's 2021 IRP, the Commission cautioned PacifiCorp that the company's cost-benefit analyses lacked "the holistic explanation of costs and benefits that we expect companies to provide in the IRP and which stakeholders and ratepayers should expect to receive for a multi-billion-dollar resource addition."[10] This led the Commission to direct PacifiCorp to "produce the full cost

[6] *In re PacifiCorp, dba Pacific Power, Application for Approval of 2020 All-Source Request for Proposal*, Docket No. UM 2059, Order No. 21-437 at 16 (Nov. 24, 2021).
[7] *Id.*
[8] *Id.* at 15.
[9] *Id.*
[10] *In re PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan*, Docket No. LC 77, Order No. 22-178 at 11 (May 23, 2022).

information for [Gateway South] in the rate cases where it seeks to place them into rate base."[11]

Q. Did PacifiCorp provide what it believed were complete analyses of the costs and benefits provided by Gateway South in its most recent general rate case?

A. Yes. I provided several analyses of the cost and benefits of Gateway South. These included: (a) PacifiCorp's PVRR(d) analyses of across five price-policy scenarios; (b) the same scenarios, adjusted for risk; (c) the same scenarios assuming Gateway South (and Gateway West) were unavoidable; (d) how removal of Gateway South would impact the company's resource portfolio by removing almost 2 gigawatts (GW) of wind resources before 2030 alone, and by increasing exposure to market purchases by nearly 20 percent annually; (e) analyzed changes in system costs with and without Gateway South; (f) discussed additional REC-benefits provided by the resources interconnected by Gateway South; (g) considered several sensitivities that could impact the company's analyses, including changes in capital costs and analyzing stochastic risk benefits; and (f) revisited my economic analyses to address impacts caused by the COVID-19 pandemic and the passage of the IRA.[12]

Q. Did PacifiCorp address concerns regarding whether it should have delayed investments in Gateway South?

A. Yes. I detailed PacifiCorp's decision to prioritize the construction of Gateway South, as the line would allow for a significant interconnection of new generation resources to address a significant capacity deficit—starting at 1,071 MW in 2021 and increasing to

[11] *Id.*at 12.
[12] *In re PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision,* Docket No. UE 433, Direct Testimony of Rick T. Link at 28-36 (PAC/800, Link/28-36) (Feb. 14, 2024).

over 6,600 MW by 2040. In 2025, the first full year that Gateway South would be online, this resource need was 1,627 MW.[13] I also analyzed the timing of when Gateway South should come online, which demonstrated that without Gateway South (and Gateway West), the company's preferred portfolio would have been $260 million more expensive for customers, primarily due to increased exposure to and volatility of market prices, loads, hydro generation, and unplanned outages.[14] Finally, I highlighted the fact that Internal Revenue Service guidance at the time was clear that the only way the 2 GW of wind facilities that depended on Gateway South would receive PTCs was if each resource came online before 2026.[15]

Q. What was your conclusion from these analyses?

A. I concluded that PacifiCorp's estimates of both the forecasted benefits that Gateway South would provide Oregon customers, as well as the timeline to invest in this resource to come online before 2026, supported the prudency of the company's decisions.

Q. Did the Commission agree with your conclusion?

A. Partially. After reviewing PacifiCorp's analyses, and concluding that Gateway South would be used and useful once placed in service, the Commission noted that PacifiCorp "failed to provide sufficient analysis to justify its decision to construct the line sooner rather than later."[16] The Commission further identified that in order to receive a full return on Gateway South, PacifiCorp must demonstrate "in its next rate case, that the

[13] Docket No. UE 433, Reply Testimony of Rick T. Link at 6-8 (PAC/2500, Link/6-8) (July 26, 2024).
[14] Docket No. UE 433, PAC/2500, Link/8-9 (citing to Docket No. LC 77, PacifiCorp's 2021 IRP, Vol. I: Chapter 9 – Modeling and Portfolio Selection Results at 274 (Sept. 1, 2021)).
[15] Docket No. UE 433, PAC/2500, Link/12-13.
[16] Docket No. UE 433, Order No. 24-447 at 42 (Dec. 19, 2024).

benefits identified in planning have materialized to produce a net benefit to customers."[17]

Q. Does your testimony address how net benefits from Gateway South are materializing for Oregon customers?

A. Yes. My testimony below discusses—and largely confirms—that the forecasted benefits of Gateway South are materializing, and that Oregon customers will continue to benefit from this resource over its remaining 65-year service life. These benefits include increased resource diversity that provides substantial net power cost benefits and reduced curtailment of wind facilities. The addition of non-emitting resources enabled by Gateway South, and the reduction in wind curtailments, also helps PacifiCorp make progress toward meeting its compliance obligations under HB 2021 and Oregon's RPS.

Q. Starting with wind curtailment, has Gateway South decreased the amount of wind resources that otherwise would have been curtailed due to congestion?

A. Yes. PacifiCorp analyzed wind energy generation since Gateway South came online in December of 2024, and compared this to the level of wind curtailment over roughly the same period in the winter of 2023/2024. This analysis demonstrates that the hours of wind curtailments decreased from [redacted] percent in 2023/2024, to just [redacted] percent in 2024/2025. In the 2,654 hours of wind generation over each study period, [redacted] hours experienced some degree of wind curtailment in the prior period, with only [redacted] hours in the latter period where Gateway South was online. This means that Gateway South

[17] *Id.* at 42.

has avoided almost [redacted] of hourly wind curtailments in just a few months.

Gateway South greatly reduced wind curtailments even though an additional 481.5 MW of Wyoming wind resources became operable at the end of 2024 that was not online during the directly comparable study period in 2023/2024.[18] Uncurtailed wind generation totaled [redacted] over the 2024/2025 study period (with Gateway South and incremental wind) and [redacted] in the 2023/2024 study period (without Gateway South and incremental wind). Only [redacted] of Wyoming wind resources have been curtailed since Gateway South came online [redacted] of total generation curtailment), compared to [redacted] in the prior period [redacted].

The results of PacifiCorp's curtailment analysis is summarized below in Table 1.

[18] These wind resources include Anticline at 100.5 MW, Boswell Springs at 320 MW, and 61 MW from the partially constructed Rock Creek I wind project.

Table 1 – Gateway South Avoided Wind Curtailments

Wyoming Variable Energy Resources	Post-GWS Curtailments (12/3/2024 - 3/23/2025)	Pre-GWS Curtailments (12/3/2023 - 3/22/2024)[19]
Number of Hours in Sample	2654	2654
Number of Hours Curtailed	[redacted]	[redacted]
Percent of Hours Curtailed	[redacted]	[redacted]
Average of hourly volume curtailed	[redacted]	[redacted]
Average volume of curtailment	[redacted]	[redacted]
Total Wind Generation (MWh)	[redacted]	[redacted]
Total Un-Curtailed Wind Generation (MWh)	[redacted]	[redacted]
Total Curtailed Volume (MWh)	[redacted]	[redacted]
Percent of Total Gen Curtailed	[redacted]	[redacted]

Q. Moving to power cost benefits, has PacifiCorp quantified the net power cost savings to Oregon customers created by Gateway South for 2026?

A. Yes. Excluding revenue requirement impacts from the costs associated with Gateway South, the additional wind and transmission capacity provided by Gateway South reduces Oregon customer rates by $63 million in 2026. As discussed in the testimony of Ramon Mitchell in the company's 2026 Transition Adjustment Mechanism (TAM) filing, this $63 million reduction in rates for Oregon customers includes $44 million in net power costs, and $19 million in quantifiable increased PTC benefits.[20]

Q. Does Gateway South provide any additional PTC benefits?

[19] Because 2024 was a leap year, the analysis of December 3, 2023 through March 22, 2024 includes February 29, 2024. This explains why the time periods differ by one day (March 22, 2024, compared to March 23, 2025). However, the number of sample hours, 2,654, remain the same in both periods.

[20] *In re PacifiCorp's 2026 Transition Adjustment Mechanism,* UE __, Direct Testimony of Ramon Mitchell (Apr. 1, 2025) (PAC/100).

A. Yes. Gateway South has already led to, and will continue to support, a substantial increase in PTCs for Oregon customers. It is important to note that the $19 million of increased quantifiable PTC benefits is based on production from Rock Creek I and Rock Creek II, which are or will be owned by PacifiCorp. Contracted resources dependent upon Gateway South have pricing that reflect PTC benefits realized by the project developers; however, PacifiCorp cannot expressly isolate the level of PTC benefit reflected in the contract price. Consequently, these benefits are reflected in the $40 million power cost benefits referenced above.[21] It is expected that PTC benefits will further increase when Gateway South's 2,030 MW of interconnection capacity is fully subscribed by incremental qualifying resources.

Q. Based on the information PacifiCorp knew when it decided to invest in Gateway South, would Oregon customers have benefited from these PTCs if PacifiCorp did not decide to move forward with Gateway South when it did?

A. No. It is important to stress that PacifiCorp's decision to move forward with Gateway South in June 2022, predated passage of the IRA in August 2022. Based on PacifiCorp's then-known and knowable information regarding PTC eligibility, if PacifiCorp decided to delay construction of Gateway South by even one year, all the wind resources that depended on Gateway South to come online would have been ineligible for federal PTCs. This would have significantly impacted the value provided by these resources.

Q. Does Gateway South provide any additional benefits not already addressed?

[21] The current list of projects dependent upon Gateway South includes Anticline at 100.5 MW, Boswell Springs at 320 MW, Rock Creek I at 190 MW, Rock Creek II at 400 MW, and Cedar Springs IV at 350.4 MW.

A. Yes. Gateway South is important for PacifiCorp's progress toward complying with HB 2021 greenhouse gas emissions reductions requirements and the Oregon RPS.

Q. How does Gateway South support PacifiCorp's progress toward compliance with HB 2021?

A. PacifiCorp estimates that Gateway South will enable the generation of approximately 1.5 million MWh of Oregon-allocated wind generation each year, as indicated by Mr. Mitchell's analysis for the company's 2026 TAM.[22] When PacifiCorp reports its annual greenhouse gas emissions for 2026 to the DEQ, this additional wind generation will substantially decrease PacifiCorp's emissions by reducing reliance on other emitting generation resources or unspecified market purchases. Assuming, even conservatively, that the entirety of the generation enabled by Gateway South was replaced with unspecified market purchases (and not some combination of unspecified purchases, natural gas generation, and coal generation), PacifiCorp's greenhouse gas emissions are substantially reduced.

For example, unspecified market purchases have a 0.428 metric tons of carbon dioxide equivalent per megawatt-hour (MT CO2e/MWh) emissions factor.[23] Multiplying this unspecified emissions factor by the anticipated 1.5 million MWh of Oregon-allocated wind generation each year results in an estimated 642,000 of avoided MT CO2e.[24] This represents an 8.39 percent reduction in PacifiCorp's greenhouse gas

[22] Docket No. UE 450, PAC/100.
[23] OAR 340-215-0120(2)(a).
[24] Actual emissions will be reported to the DEQ in future emissions reports, and available in subsequent PacifiCorp Clean Energy Plans.

emissions from its 2023 levels,[25] and nearly 11 percent of the progress necessary to reach HB 2021 compliance obligations in 2030.[26]

Q. Why does PacifiCorp believe these emissions reduction benefits provided by Gateway South are conservative?

A. Notably, the unspecified market purchase emissions factor is significantly lower than the average emissions factor for PacifiCorp's existing natural gas fleet that would likely otherwise serve Oregon customers. For example, PacifiCorp's natural gas fleet includes 3,852 MW resources across four states.[27] The DEQ has created facility-specific emissions factors for each of these natural gas resources.[28] The simple average of each of the emissions factors included in the DEQ's workbook is 0.9974 MT CO2e/MWh.[29] The facility-specific emissions factors for PacifiCorp's coal resources would be even higher.

Multiplying the higher natural gas emissions factor by the anticipated 1.5 million MWh of Oregon-allocated wind generation enabled by Gateway South results in an estimated 1,496,100 of avoided MT CO2e each year. This equates to a 19.55 percent reduction in PacifiCorp's greenhouse gas emissions from 2023 levels, and over 25 percent of the progress necessary to reach HB 2021 compliance obligations in 2030.

[25] PacifiCorp reported actual emissions to the Oregon DEQ of 7,653,943 MT/CO2e in 2023.
[26] The Oregon DEQ defines PacifiCorp's 2030 obligation as an 80 percent reduction in emissions from the baseline, which amounts to only 1,798,890 MT/CO2e emitted in 2030.
[27] *E.g.,* PacifiCorp's 2025 Draft IRP, Table 6.3 (available here: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/2025_DRAFT_IRP_Vol.1.pdf).
[28] *E.g.* "DEQ assigned emission factors for use in the 2025 CEP," Greenhouse Gas Emission Factors for HB 2021 Electricity Sector Emission Projections Excel Workbook (available here: https://www.oregon.gov/deq/ghgp/Pages/Clean-Energy-Targets.aspx) (link to excel workbook here: https://www.oregon.gov/deq/ghgp/Documents/HB2021-EmissionFactors.xlsx).
[29] *Id.*

Q. Overall, what are your conclusions regarding the emissions reduction benefits provided by Gateway South?

A. Gateway South will likely reduce PacifiCorp's greenhouse gas emissions by an estimated 8.39 to 19.55 percent from 2023 levels. These avoided emissions, even when relying only on unspecified market purchases to replace the wind generation provided by Gateway South, are anticipated to be the single largest reduction in PacifiCorp's Oregon-allocated greenhouse gas emissions since the company began reporting emissions to DEQ. These emissions will be avoided each year that the resources interconnected to Gateway South maintain operation, and will materially contribute to PacifiCorp's ability to comply with HB 2021.

Q. Next, how does Gateway South impact PacifiCorp's RPS compliance obligation?

A. PacifiCorp anticipates that Gateway South will enable the generation of approximately 1.5 million Oregon-allocated RECs each year (conservatively, assuming no new renewable generation enabled by Gateway South is added in the future). This volume of RECs amounts to approximately 30 percent of PacifiCorp's 2030 RPS requirement, based on the most recent forecast that show an RPS requirement of 4,993,038 MWh RECs.[30]

Because PacifiCorp retains all Oregon-allocated RECs for compliance with Oregon-specific policies (and does not re-sell them in the market), there is no additional revenue that could be used to reduce customer rates. Instead, these additional RECs will be used to meet PacifiCorp's obligations under the RPS and directly benefit Oregon customers by increasing the percentage of electricity that our customers can

[30] ORS 469A.052(1)(f) (requiring a 35 percent clean energy standard by 2030), calculated based on most recent Oregon retail sales forecast included in PacifiCorp's 2025 Integrated Resource Plan.

claim as renewable generation. In the event RPS requirements are satisfied in future years, the company can re-evaluate its compliance strategy to determine if the re-sale of these Oregon-allocated RECs would provide greater benefits to Oregon customers (all revenue would be returned to customers through annual power cost adjustment filings).

Q. What conclusions do you believe the Commission should reach based on the net benefits you discussed above?

A. I believe that the current and forecasted net benefits provided by Gateway South more than support the company's decision to move forward with its investments in Gateway South. Please see the testimonies of Mr. Vail and Mr. Tsoukalis for additional reliability benefits provided by this transmission asset.

IV. ROCK CREEK I AND II

Q. Please describe the company's acquisition of the Rock Creek projects.

A. As described in the confidential testimony of Jeffrey M. Wagner, PacifiCorp has acquired the 190 MW Rock Creek I and will acquire the 400 MW Rock Creek II facilities. These projects have been and will be built by Invenergy under build-transfer agreements (BTAs) and will be transferred to the company upon completion. My testimony provides the economic justification for PacifiCorp's decision to acquire these resources.

A. <u>Resource Need</u>

Q. Please provide an overview of PacifiCorp's IRP process.

A. PacifiCorp's IRP process uses thorough analysis and modeling that measures cost and risk to develop the company's plans to provide reliable and reasonably priced service for its customers. The primary objective of the IRP is to identify the least-cost, least-

risk portfolio of resources that can serve customers in the future with manageable risks.

PacifiCorp completes an IRP cycle every two years, with a full IRP in odd-numbered years and an update to the full IRP in even-numbered years. PacifiCorp submits both its IRP and IRP Update to each of the six regulatory commissions in the states where it provides retail service. Each IRP is developed through an open and public process, with input from an active and diverse group of stakeholders, including state regulatory commissions, state consumer-advocacy departments, customer-sponsored advocacy groups, environmental-advocacy groups, resource-advocacy groups, independent-power producers, project developers, other utilities, and customers. During the public-input process, which typically spans at least a full year before the release of a full IRP, PacifiCorp holds regular meetings with stakeholders to solicit feedback on planning assumptions, methodologies, and model results.

Q. Did PacifiCorp's 2021 IRP identify a need for additional resources?

A. Yes. The primary focus of any IRP is to forecast the need for resources and evaluate different strategies to meet that need over time. The 2021 IRP indicated that PacifiCorp has a capacity deficit in all years of the planning horizon—starting at 1,071 MW in 2021 and increasing to over 6,600 MW by 2040. The resource need in the 2021 IRP for 2025 is 1,627 MW. As described further below, this need has increased since the 2021 IRP was released.

Q. How does the 2021 IRP preferred portfolio address the need for new resources?

A. The 2021 IRP preferred portfolio represents PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period. Using a range of cost and risk metrics to evaluate numerous resource portfolios, PacifiCorp's preferred

portfolio reflects a cost-conscious plan that includes near-term investments in renewable resources that capture significant tax credits before they expire or decrease, and new transmission infrastructure to facilitate the interconnection and delivery of these resources. These new resources and transmission investments are lower cost than other resource and transmission alternatives and are necessary to reliably serve our customers.

Q. Can you describe the methodology that PacifiCorp used in the 2021 IRP to analyze the economics of the preferred portfolio?

A. Yes. For the 2021 IRP, PacifiCorp incorporated a new and more advanced optimization modeling system called PLEXOS. The PLEXOS modeling system provides three platforms (referred to as Long-term (LT), Medium-term (MT) and Short-term (ST)), which work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon.

Q. Does PacifiCorp have a need for Rock Creek I and II?

A. Yes. As discussed above, the 2021 IRP preferred portfolio shows that PacifiCorp needs new resources. In this plan, the company proposed to begin addressing this need with 1,792 MW of new wind generation resulting from the 2020 All Source RFP, which included both Rock Creek projects.[31]

Q. Please describe key factors that support including the Rock Creek projects in the 2021 IRP preferred portfolio.

A. The projects are expected to meet the company's near-term resource need and provide significant customer benefits by providing zero-fuel cost generation and substantial

[31] Docket No. LC 77, PacifiCorp's 2021 IRP, Vol. I at 253-318.

PTC benefits, while mitigating risks associated with future regulation of carbon-emitting resources. The addition of non-emitting wind resources further improves PacifiCorp's ability to make incremental progress toward achieving emission-reduction targets set forth in HB 2021.

Q. Please describe the reliability benefits of projects like Rock Creek I and II.

A. Acquiring the Rock Creek projects reduces PacifiCorp's exposure to price and volume volatility by reducing the need for market purchases. Increased reliance on the market exposes customers to price volatility and price spikes that occur when the region experiences severe weather events or system disruptions. Such events increase net power costs, and the magnitude of increase is directly proportional to the volume of purchases needed. In short, there is no guarantee that there will be a seller when PacifiCorp needs to make a short-term purchase to serve its load. This risk also exists for firm forward market purchases, where the seller could cut scheduled deliveries and accept liquidated damages if they do not have sufficient supply to meet their contractual obligations of the sale. Western Electricity Coordinating Counsel and North American Electric Reliability Corporation (NERC) reliability studies available at the time of this filing highlight the risks of resource shortfalls across the region in the coming years.[32] Moreover, as discussed earlier in my testimony, unspecified market purchases are

[32] *2020 Western Assessment of Resource Adequacy Report*, Western Electricity Coordinating Council (Dec.18, 2020), *available at*: https://www.wecc.org/sites/default/files/documents/communications/2024/Western%20Assessment%20of%20Resource%20Adequacy%20Report%2020201218.pdf; *2021 Western Assessment of Resource Adequacy Report*, Western Electricity Coordinating Council (Dec. 17, 2021), *available at*: https://www.wecc.org/sites/default/files/documents/program/2024/WARA%202021.pdf; *2020 Long-Term Reliability Assessment*, North American Electric Reliability Corporation (Dec. 2020), *available at*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf; *2021 Long-Term Reliability Assessment*, North American Electric Reliability Corporation (Dec. 2021), *available at*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

assigned a default emissions factor, which makes it directionally more difficult to achieve the emission-reduction targets set forth in HB 2021.

Q. How do these studies relate to the Rock Creek projects?

A. Each of these studies confirm the generally accepted understanding that the west is facing increasing resource adequacy risks in the near term. NERC further confirmed these findings and warned in its 2022 Summer Reliability Assessment that several regions in North America were at high or elevated risk of power outages this past summer due to above-normal temperatures and drought conditions, particularly in the western half of Canada and the United States.[33]

The Rock Creek projects will help mitigate the risk that there may be inadequate supply to support market purchases, and reduce exposure to price spikes in periods where demand threatens to exceed supply for market purchases while reducing emissions in accordance with HB 2021.

Q. Were both Rock Creek I and II selected in the 2020 All Source RFP?

A. Yes. The 2020 All Source RFP final shortlist included six final shortlist bids representing over 1,600 MW of wind generation seeking to interconnect to PacifiCorp's transmission system. These bids include Rock Creek I and II, which were the only two bids that were not power purchase agreements.

Q. Following their selection to the 2020 All Source RFP final shortlist, did PacifiCorp begin negotiating BTAs for the Rock Creek Projects?

[33] *2022 Summer Reliability Assessment*, North American Electric Reliability Corporation (May 2022) *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf.

A. Yes. Both Rock Creek I and Rock Creek II were proposed by Invenergy, and as discussed by Mr. Wagner, PacifiCorp engaged in BTA negotiations with Invenergy for both projects.

Q. Were negotiations impacted by contemporaneous economic conditions?

A. Yes. Bidder development efforts were challenged by importation restrictions related to China, COVID-19 international impacts, and hostilities in Ukraine that created significant logistics and supply chain challenges associated with solar panels, wind turbines, lithium batteries, transformers, and many balance-of-plant materials. As a result, many developers were forced to abandon established supply chains and revert to new suppliers (if available), which materially impacted overall renewable power plant pricing and commitments toward project in-service dates.

Given PacifiCorp's need for generation resources, PacifiCorp allowed pricing adjustments from all final shortlist projects from the 2020 All Source RFP, as well as limited extensions to commercial operations dates. Despite this additional flexibility, some of the bids from the final shortlist were unable to provide firm prices and were not available for selection. This eliminated 902 MW of solar capacity and 497 MW of battery capacity that was initially included in the 2020 All Source RFP final shortlist.

Q. Did these economic factors impact the cost of the Rock Creek projects relative to the costs offered in the initial bid that were used to establish the final shortlist?

A. Yes. Given the market dynamics discussed above, the overall costs for the Rock Creek projects increased from their initial bids in the 2020 All Source RFP. The economic analysis below is based on these updated project costs.

Q. Were there additional benefits associated with the Rock Creek projects that offset these increased costs?

A. Yes. PacifiCorp's original economic analysis in the 2020 All Source RFP assumed that the Rock Creek projects qualified for a 60 percent PTC through the first 10 years of operation. As a result of the IRA, the economic analysis in this case reflects the value of the 110 percent PTC, in addition to the updated project costs. These updates cause a significant and positive change in the economic benefits of both projects.

Q. Have economic drivers also impacted PacifiCorp's resource needs?

A. Yes. While the costs of 2020 All Source RFP bids increased, PacifiCorp's resource need also increased. It is also important to consider the broader regional capacity need that aligns with the company's need and expected in-service date for the Rock Creek projects. The 2020 All Source RFP included virtually every potential non-market resource in the region capable of achieving commercial operation by 2025. Meeting this near-term need with physical assets that will provide incremental generation capacity effectively limits PacifiCorp's options to procure new resources to bidders that participated in the 2020 All Source RFP.

Therefore, Rock Creek projects remain necessary to reliably serve customers and the projects' selection in the 2020 All Source RFP confirms they are among the least-cost, least-risk resources available to meet the company's need.

Q. Did PacifiCorp prepare an update to the 2021 IRP?

A. Yes. On March 31, 2022, the company issued its 2021 IRP Update.[34]

Q. What is the purpose of the 2021 IRP Update?

[34] PacifiCorp 2021 Integrated Resource Plan Update (Mar. 31, 2022)(https://www.pacificorp.com/energy/integrated-resource-plan.html).

A. The IRP update is a checkpoint on the IRP action plan and ensures that changes in the planning environment are considered between the two-year IRP planning cycle. The 2021 IRP Update assessed whether evolving trends and events impact customers and required changes to the action plan to deliver resources and transmission investments. Relevant here, the 2021 IRP Update reflects resource planning and procurement activities that occurred since the 2021 IRP and presents an updated load-and-resource balance and an updated resource portfolio.

Q. Were Rock Creek I and II included in the 2021 IRP Update preferred portfolio?

A. Yes.[35]

Q. Were there any important modeling updates in the 2021 IRP Update?

A. As discussed in Chapter 5 of the 2021 IRP Update, key updates included revised load-and-resource balances, and resource changes due to 2020 All Source RFP activity. Importantly, the Environmental Protection Agency's (EPA) pre-publication version of the Ozone Transport Rule (OTR), released on March 11, 2022, was not modeled in the 2021 IRP Update.

Q. Did the 2021 IRP Update continue to show a need for additional generation resources?

A. Yes. The need increased due to an increase in the load forecast. The 2021 IRP Update shows a resource need in all years of the planning horizon—starting at 1,584 MW in 2022 and increasing to 6,755 MW in 2040. In 2025, the resource need is 1,867 MW, an increase of 240 MW, or approximately 15 percent, relative to the resource need identified in the 2021 IRP.[36] The higher load reflected in the 2021 IRP Update

[35] Docket No. LC 77, PacifiCorp 2021 IRP Update at 103 (Mar. 31, 2022).
[36] *Id.* at 47.

approaches the level analyzed in the high-load sensitivity conducted in the 2021 IRP. The most recent load forecast is even higher than that assumed in the 2021 IRP Update.

Moreover, now that the 2020 All Source RFP has ended, PacifiCorp was unable to execute firm contracts with all projects on the final shortlist. Due to national tariff policies, global supply-chain issues, and inflationary pressures, some projects on the 2020 All Source RFP final shortlist were unable to move forward.

Q. Does the 2021 IRP Update consider the previously mentioned reliability issues related to reliance on market purchases?

A. Yes. Given near-term concerns over resource adequacy, and because of the acquisition of additional resources including the Rock Creek projects, the 2021 IRP Update's preferred portfolio shows generally lower market purchases in the first five years relative to the 2021 IRP preferred portfolio.[37]

B. Modeling Assumptions and Methods

Q. Did PacifiCorp analyze Rock Creek I and Rock Creek II together?

A. Yes, for the most part. As stated above, there were two BTA wind facilities in the 2020 All Source RFP final shortlist: Rock Creek I and Rock Creek II. The second facility is larger than the first at 400 MW compared to 190 MW. Before passage of the IRA, PacifiCorp analyzed the projects separately. After passage of the IRA, the company analyzed the projects together. This combined analysis provides a more comprehensive overview of the net benefits or costs that customers would receive from these resources.

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analysis of Rock Creek I and II.

[37] *Id.* at 12 (Figure 1.11).

A. The economic analysis of Rock Creek I and II included three price-policy scenarios—medium natural gas paired with medium CO_2 prices (MM), medium natural gas prices without a CO_2 price (MN), and low natural gas without a CO_2 price (LN) price-policy scenarios. While the MM price-policy scenario represents PacifiCorp's "expected case" describing likely future conditions, the other scenarios provide additional analyses to understand how alternative assumptions affect customer benefits.

These assumptions influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale power prices and CO_2 policy assumptions affect net power cost benefits and other variable-cost benefits not explicitly captured in net power costs. These assumptions also affect forward-looking incremental system fixed-cost benefits associated with Rock Creek I and II. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. Table 2 summarizes the price-policy scenarios.

Table 2. Price-Policy Scenario Assumption Overview

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
MM	$4.52	$12.10/ton starting 2025 rising to $51.40/ton in 2040
MN	$4.52	None
LN	$2.92	None
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. Please describe the natural gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's official forward price curve (OFPC) dated June 30, 2022, which was the most current OFPC available when PacifiCorp prepared its modeling inputs for the 2020 All Source RFP. The first 36 months of the OFPC reflect market forwards at the close of a given trading day (June 30, 2022, in this case). As such, these 36 months are market forwards as of June 2022. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects Aurora-forecast prices.

Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used two different CO_2 price scenarios—zero and medium. The medium scenario is derived from a survey of third-party industry experts, including IHS Cambridge Energy Research Associates (CERA) and Wood Mackenzie and the Energy Information Administration, as well as CO_2 price assumptions used by peer utilities. The resulting CO_2 price is applied as a tax beginning in 2025.

Q. Does the inclusion of potential future CO_2 costs reflect prudent utility planning?

A. Yes. PacifiCorp's price-policy scenarios include varying levels of assumed CO_2 costs to reflect the fact it is more likely than not that some policy will exist that will reduce emissions for carbon emitting resources. When determining CO_2 costs used for planning purposes, PacifiCorp strives to ensure that it is not an outlier, and the medium price is within a reasonable range used by the industry to assess risk and conduct prudent resource planning. The most recent example of this trend is the EPA's proposed OTR restricting nitrogen oxide (NO_X) emissions from power plants and other industrial

sources. At the time PacifiCorp conducted its economic analyses, this rule would have imposed new environmental compliance obligations beginning in 2023 and 2024 on coal units in Utah and Wyoming, respectively, with more severe limitations applicable in both states by 2026.[38]

Q. Are modeled CO_2 costs intended to represent a carbon tax?

A. No. Modeled CO_2 costs are not intended to explicitly account for a future tax on CO_2 emissions. Rather, these costs capture the effect of policies incentivizing reduced emissions through benefits or imposing costs through penalties or other costs resulting from market dynamics driving the need or desire for zero-emission resources or customer preferences.

Q. Did PacifiCorp update its load forecast in its analysis of Rock Creek I and II?

A. Yes. The company used a sales and load forecast that was completed in May 2022.

Q. How does the May 2022 forecast compare to the load forecast used in the 2021 IRP?

A. Figures 1 and 2 show PacifiCorp's May 2022 load and peak forecast relative to the 2021 IRP before incremental energy efficiency savings. A higher load forecast is being driven by new industrial and commercial customer growth, increased air conditioning saturations and miscellaneous devices and electric vehicle adoption expectations. The updated load forecast also accounts for updates to weather, temperature, and line losses to account for the progression of historical data since the load forecast that informed the 2021 IRP.

[38] While these requirements have been subject to federal litigation and subsequent agency review (s*ee, e.g., Wyoming, et al., v. United States Environmental Protection Agency, et al.,* 78 F.4th 1171 (10th Cir. 2023); *Utah, et al., v. United States Environmental Protection Agency, et al.,* No. 23-9509 (Jul. 27, 2023)), the company's economic analyses reflects then-current assumptions that the OTR would be in effect.

On average, over the 2023 through 2040 timeframe, forecast system load is up 13.6 percent per year and forecast coincident system peak is up 14.1 percent per year when compared to the 2021 IRP. Over that same timeframe, the average annual growth rate for the May 2022 forecast, before accounting for incremental energy efficiency improvements, is 2.04 percent for load and 1.66 percent for peak.

Figure 1. Forecast Annual System Load

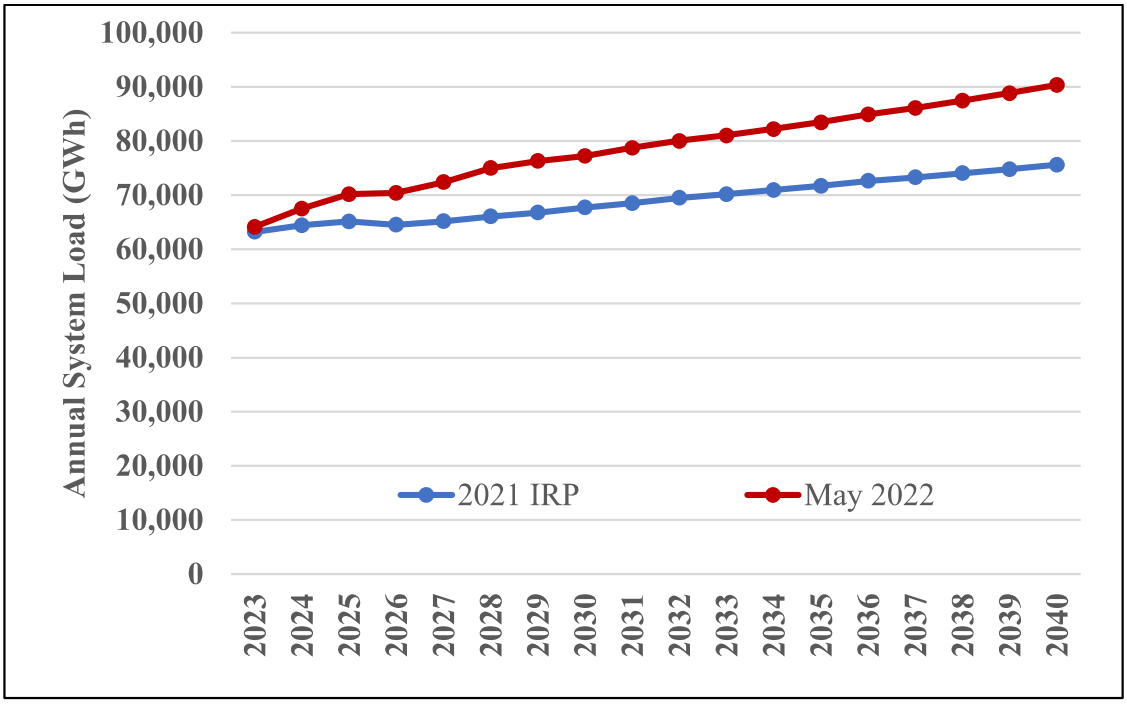
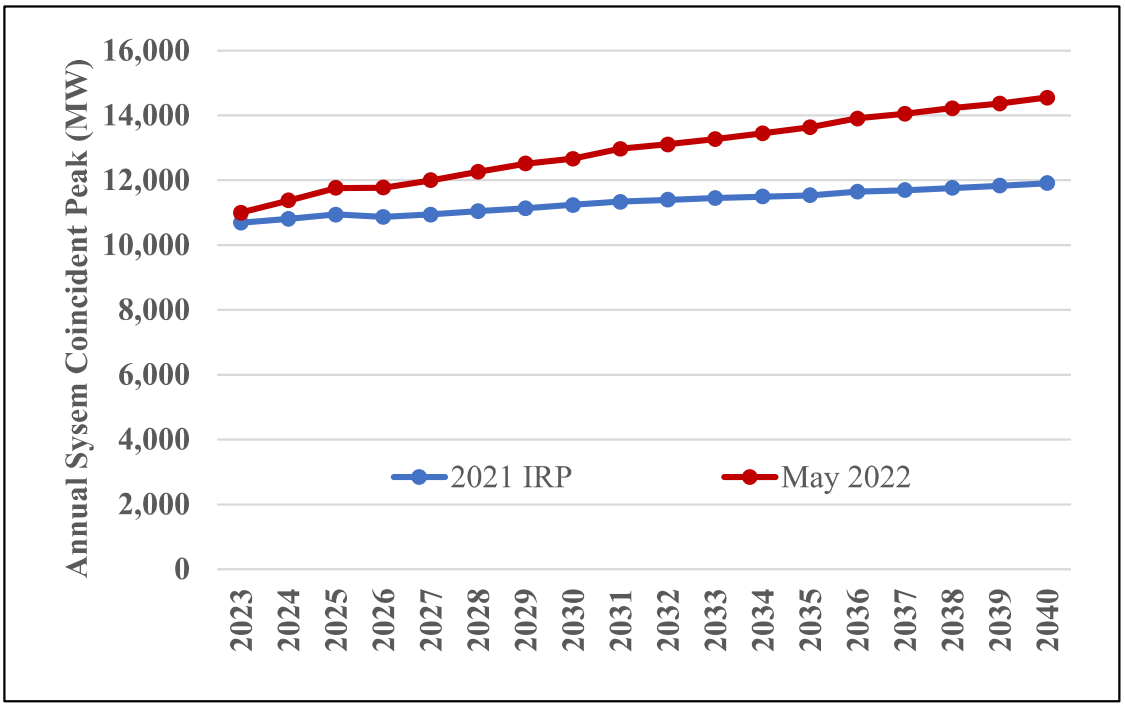


Figure 2. Forecast Annual System Coincident Peak



Q. Given its applicability at the time, did PacifiCorp incorporate the EPA's proposed OTR in its analysis of Rock Creek I and II?

A. Yes. PacifiCorp modeled two primary components to reflect the OTR: NO_X allowance requirements for each of its units including penalties for units with high emissions rates, and a dispatch target or shadow price for NO_X allowances, which is used to avoid producing NO_X emissions during periods when the economic benefits are relatively low. After running the model, PacifiCorp compared the results to forecasts of its annual allocation of OTR NO_X allowances for Utah and Wyoming.

Q. Please describe how the annual allocation of NO_X allowances would work under the proposed rule.

A. The proposed rule called for dynamic budgeting of NO_X allowances in 2025 and beyond, with available allowances allocated among resources within a state based on the recent historical heat input and emissions rates of each resource. Under the EPA's

proposed rule, the forecast allocation of NO_X allowances drops significantly in 2026, as the EPA assumed that selective catalytic reduction (SCR) installations at eligible facilities would significantly reduce emissions by that year. PacifiCorp's thermal facilities in Utah would be covered by the rule beginning 2023 and thermal facilities in Wyoming could be covered by the rule beginning 2024.

While trading of NO_X allowances among participating states is allowed, the proposed OTR includes significant penalties if a state's emissions exceed 121 percent of its annual allocation. Limited banking of NO_X allowances is also allowed, but emissions met via banked allowances may also be subject to penalties if a state's emissions exceed 121 percent of its annual allocation. To avoid such penalties, PacifiCorp's NO_X emissions during the ozone season (May through September) in each state cannot exceed 121 percent of PacifiCorp's forecast allocation of NO_X allowances for that state.

Q. Please describe how PacifiCorp developed NO_X allowance requirements for each of its units.

A. In general, an allowance for one ton of NO_X emissions would allow the holder of the allowance to emit one ton of NO_X. However, starting in 2027,[39] the proposed OTR also imposes a daily NO_X emissions rate limit of 0.14 pounds-per-million British thermal units (lb/MMBtu) for each coal-fired facility, and requires emitters to provide an equivalent of triple allowances for any emissions that exceed that rate. For example, a resource with an emissions rate of 0.20 lb/MMBtu would have an effective allowance

[39] Coal units that currently have SCR installed must meet the daily backstop limit in 2024. Coal units that do not currently have SCR installed must meet the daily backstop limit in 2027.

requirement of 0.32 lb/MMBtu.[40] To calculate PacifiCorp's NO_X allowance requirements under the OTR, starting in 2027 the modeled emission rates for coal resources whose emissions exceed 0.14 lb/MMBTU were grossed up to account for the additional surrender of allowances.

Q. Please describe how PacifiCorp developed a dispatch target to manage its NO_X allowance requirements.

A. While allowance trading is allowed under the EPA's proposed OTR, the restrictions on inter-state transfers limit the number of potential counterparties. PacifiCorp's generation fleet is an appreciable portion of the electric generating units in both Utah and Wyoming, so the potential counterparties that could have allowances available for sale within those states is quite limited. With that in mind, PacifiCorp's current planning assumes that it will comply with the OTR using only its own combined allocation of NO_X allowances and is meant to ensure that its annual allowance requirements do not exceed 100 percent of the sum of its Utah and Wyoming allowance allocations. When combined with state-specific limits previously described, while either PacifiCorp's Utah or Wyoming NO_X allowance requirements could be up to 121 percent of that state's allocation, any increase in one state would have to be accompanied by a reduction in emissions allowance requirements from PacifiCorp resources in the other state.

PacifiCorp's primary production cost analysis relies upon PLEXOS ST modeling that identifies system costs for a single deterministic set of expected or normal input conditions. In reality, and in stochastic modeling the company performs

[40] Effective allowance requirement for resource with emissions rate of 0.20 lb/MMBTU: 100% * 0.20 lb/MMBtu + 200% * (0.20 – 0.14) lb/MMBtu = 100% *0.20 + 200% * 0.06 = 0.32 lb/MMBtu.

using the PLEXOS MT model, significant variations in inputs such as load, hydro generation, and thermal availability are a normal course of operations. Each of these inputs can unexpectedly increase PacifiCorp's need for NO_X emission allowances. Because banking and trading are limited under the OTR, variations in NO_X emissions that might otherwise average out over time must comply in every year and under every set of conditions. As a result, the NO_X allowances used under "normal" input conditions will likely need to be somewhat below the forecast limit to ensure sufficient allowances are available to meet unexpected input conditions.

PacifiCorp's analysis indicated that using a NO_X allowance dispatch target of [redacted] in the ST model would result in NO_X allowance requirements that were under PacifiCorp's forecast allocation and would leave sufficient allowances to meet a range of potential adverse conditions. Whenever the incremental value of using a high NO_X emitting resources exceeds the dispatch target price, the model will deploy the high NO_X resource, rather than lower NO_X alternatives, which are typically gas-fired resources or market transactions. For a coal-fired resource with a NO_X emissions rate of 0.20 lb/MMBtu, the NO_X dispatch target price means that the resource would not be dispatched unless it provides at least [redacted] in incremental value relative to no NO_X alternatives, or a proportional amount of incremental value relative to lower NO_X alternatives.[41]

The dispatch target price is used to direct the model to avoid emissions, and is not a direct cost, as PacifiCorp would receive its allowance allocation free of charge

[41] A 0.20 lb/MMBTU coal-fired resource would have a NO_X credit requirement of 0.32 lb/MMBTU in 2027 and beyond, as detailed in footnote 22. A typical average heat rate for a coal-fired resource is 11 MMBtu/MWh. [redacted] ÷ 2,000 lb/ton * 0.32 lb/MMBtu * 11 MMBtu/MWh = [redacted].

under the proposed rule. While the company could potentially sell allowances, there is little indication what market prices may prevail, and market prices may be below this target. As a result, no direct costs or revenues for allowances are included in the analysis. The allowance requirements resulting from this dispatch target price vary over time as the OTR requirements take full effect and as PacifiCorp's portfolio evolves. The company's load forecast and other modeling inputs also play a role in the resulting volumes. A comparison of the allowance requirements for the scenarios relative and forecast allowance allocations is discussed in the Price-Policy Scenario Results section later in my testimony.

Q. Please describe the modeling methodology PacifiCorp used in its analysis of Rock Creek I and II.

A. Consistent with IRP modeling practices, PacifiCorp calculated a system PVRR by identifying least-cost resource portfolios and dispatching system resources through 2040, which aligns with the 20-year forecast period used in the 2021 IRP and 2021 IRP Update. Net customer benefits are calculated as the PVRR(d) between different simulations of PacifiCorp's system. One simulation includes both Rock Creek I and Rock Creek II, and the other simulation excludes them. The simulation that includes both projects includes transmission interconnection costs. When the two simulations are compared, changes to system costs are attributable to both projects. These analyses reflect the value of increased PTCs after passage of the IRA, and in all studies, the Gateway West and Gateway South transmission projects were assumed to be in-service, and beyond 2025 proxy resource options from the 2021 IRP are available to

meet system needs. Finally, PacifiCorp analyzed sensitivities that quantify how changes in capital costs and PTC values influence projected customer benefits.

When reviewing the results of these analyses, customers are expected to realize benefits when the system PVRR from the simulation with the projects is lower than the system PVRR without. Conversely, customers would experience increased costs if the system PVRR with the projects is higher than the system PVRR without.

Q. Please summarize the PVRR(d) results post-IRA.

A. Table 5 summarizes the PVRR(d) results for each price-policy scenario from both resources after passage of the IRA.[42]

Table 5. Post-IRA (Benefit)/Cost of Rock Creek I-II ($ million)

	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f) = (a) + (e)	(g) = (b) + (e)
Price-Policy Scenario	**PVRR(d)**	**Risk-Adjusted PVRR(d)**	**110% PTC Update**	**Project Cost Update**	**Total Update**	**Updated PVRR(d)**	**Updated Risk-Adjusted PVRR(d)**
MM	(143)	(163)	(197)	42	(155)	(298)	(318)
MN	(33)	(51)	(194)	42	(151)	(185)	(202)
LN	16	2	(195)	42	(153)	(137)	(151)

Before adjusting for risk (Column (f)), system costs are lower when Rock Creek I and II are included in the portfolio in all scenarios: ranging from a $137 million customer benefit under the LN scenario to $298 million in the MM scenario. When adjusting for risk (Column (g)), the benefits from Rock Creek I and II increase ranging from $151 million in the LN scenario to $318 million in the MM scenario. The increase in customer benefits from the 110 percent PTC is substantial, even when accounting for the increase in project costs. This analysis supports the necessity of Rock Creek I

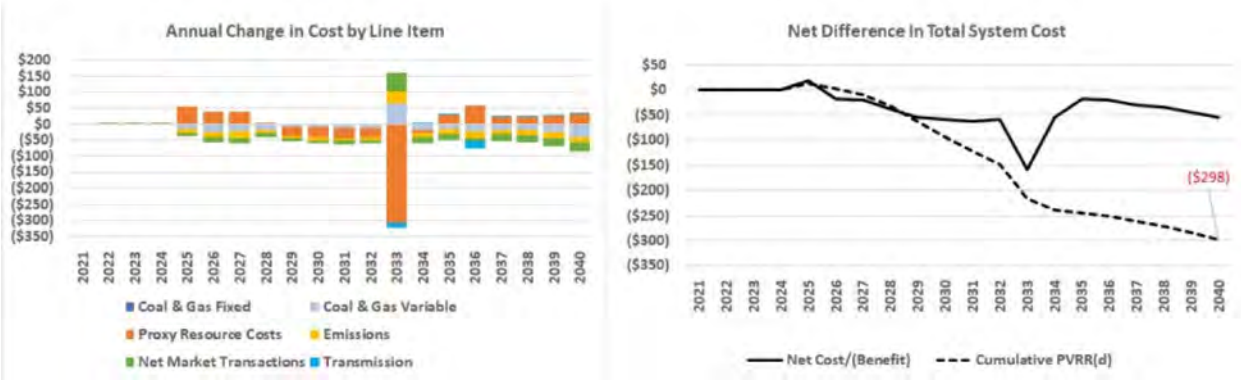
[42] *See* Confidential Exhibit PAC/301 – Combined Rock Creek I-II Analyses.

and II and indicates they will produce robust customer benefits. As discussed earlier, these benefits only increase under a high gas or a high CO_2 price-policy scenario.

Q. How do system costs change post-IRA with and without both Rock Creek I and Rock Creek II?

A. Figure 3 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when both Rock Creek I and Rock Creek II are eliminated from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio that includes Rock Creek I and II is $298 million lower cost than the portfolio without both.

Figure 3. Increase/(Decrease) in System Costs when both Projects are Removed from the Portfolio ($ millions) Medium Gas/Medium CO2



Q. How do the risk-adjusted PVRR(d) results compare to the stochastic-mean PVRR(d) results?

A. For both Rock Creek I and II, the risk-adjusted medium gas medium CO_2 PVRR(d) results show a benefit of $318 million, which is higher than the reported ST-model PVRR(d) results of $298 million prior to the risk adjustment. This indicates that Rock

Creek I and II provide stochastic risk benefits by making the system less susceptible to low -probability combinations of load, market price, hydro generation, and thermal outage volatility that can increase system costs.

Q. How do the modeled OTR allowance requirements compare to PacifiCorp's forecast allowance allocation?

A. The annual allowance requirements in the ST-model results are generally slightly below a high estimate of PacifiCorp's allowance allocation. Based on the allocation methodology identified in the proposed rule, this high allowance allocation would likely require installation of SCR equipment at most of PacifiCorp's coal-fired generating units that are not equipped with that technology. In the absence of additional emission control equipment, PacifiCorp's allocation would be significantly lower, and well below the allowance requirements from the ST-model results. The high and low allocation forecasts and the ST-model results for the MM and MN price-policy scenarios are shown in Confidential Figure 4. As shown, allowance allocations could be significantly lower than what is assumed to be available in the current ST-model results, which would further increase the value of generation from resources without emissions, such as Rock Creek I and II.

[redacted]

[redacted]

Q. Would Rock Creek I and II provide customer benefits even if construction costs were higher than expected?

A. Yes. For both projects, a one percent increase in initial capital costs would reduce PVRR benefits through 2040 by $9.1 million. To negate the $318 million in risk-adjusted, post-IRA benefits under the MM price-policy scenario, project costs would need to increase by 35 percent. To negate the $202 million in risk-adjusted, post-IRA benefits under the MN price-policy scenario, project costs would need to increase by 22 percent.

Q. Are PacifiCorp's economic analyses of the expected customer benefits from Rock Creek I and II conservative?

A. Yes. The PVRR(d) results for both projects do not reflect the potential value of RECs generated by the incremental energy output from the renewable project. Customer benefits for all price-policy scenarios would improve by approximately $14 million for every dollar assigned to the incremental RECs that will be generated through 2040.

Similarly, PacifiCorp's analyses understate forecast coal costs for certain system resources, including the Dave Johnston plant. If corrected to include the full costs of fuel supply for all plants, the company's economic analysis would demonstrate even higher benefits for Rock Creek I and II. Additionally, the natural gas and electricity prices in the company's September 2022 OFPC are higher than the values assumed in the June 2022 OFPC used in PacifiCorp's analysis, which would similarly result in higher benefits for Rock Creek I and II.

V. CONCLUSION

Q. Please summarize the conclusions of your direct testimony.

A. PacifiCorp's economic analysis shows that the company's decision to procure these resources was necessary and will provide substantial customer benefits compared to anticipated project costs.

I recommend that the Commission conclude that: (1) Gateway South provides net benefits to customers, which justifies authorizing the company to recover the full return on its invested capital; and (2) the company's decisions to acquire Rock Creek I and II were prudent.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 451
Exhibit PAC/301
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Rick T. Link

Combined Rock Creek I and II Analyses

April 2025

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

Docket No. UE 470
Exhibit PAC/204
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Rick T. Link

Vail 2026 RAC Direct Testimony

May 2026

Docket No. UE 451
Exhibit PAC/400
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Richard A. Vail

April 2025

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Exhibit PAC/401 – Follow-on Gateway West w/o Gateway South Analysis

Confidential Exhibit PAC/402 – Gateway South (Aeolus – Clover 500 kV Line Analysis)

Exhibit PAC/403 – Serial Queue Build Out with no Long-Term Transmission Plan

Exhibit PAC/404 – Aeolus West Transmission Path FAC-013 Assessment

Exhibit PAC/405 – Winter 2024-2025 Aeolus West and TOT 4B System Operating Limits

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and current position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Richard A. Vail. My business address is 825 NE Multnomah Street, Suite 1600, Portland, Oregon 97232. I am the Vice President of Transmission at PacifiCorp. I am responsible for transmission system planning, customer generator interconnection requests and transmission service requests, regional transmission initiatives, capital budgeting for transmission, transmission and distribution project delivery, and administration of the Open Access Transmission Tariff (OATT).

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science degree with Honors in Electrical Engineering with a focus in electric power systems from Portland State University. I have been Vice President of Transmission for PacifiCorp since December 2012. I was Director of Asset Management from 2007 to 2012. Before that position, I had management responsibility for a number of organizations in PacifiCorp's asset management group including capital planning, maintenance policy, maintenance planning, and investment planning since joining PacifiCorp in 2001.

II. PURPOSE OF TESTIMONY

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

A. I provide a brief overview of PacifiCorp's transmission system, and I discuss PacifiCorp's recently completed Gateway South Segment F Aeolus to Mona/Clover 500 kV transmission line (Gateway South). I discuss how Gateway South increases PacifiCorp's load serving capability, enhances reliability, conforms with North American Electric Reliability Corporation (NERC) Reliability Standards, improves

generation interconnection capacity and transfer capability within the existing system, avoids significant curtailment of cost-effective wind resources, limits exposure to market prices, and relieves existing congestion. And given its geographic location, Gateway South allows for the single largest interconnection of new wind resources into PacifiCorp's transmission system in the history of the Company—if not the West.

Finally, I demonstrate how the Rock Creek I and Rock Creek II wind projects required Gateway South to be constructed in order to connect to PacifiCorp's transmission system, and deliver that energy to serve Oregon customers, where otherwise generation from these resources would have been significantly curtailed.

Q. Overall, what are your recommendations for this proceeding?

A. I recommend that the Public Utility Commission of Oregon (Commission) find that PacifiCorp's investment in this grid-transformative transmission resource was prudent and conclude that Gateway South results in immediate and substantial benefits to Oregon customers.

III. OVERVIEW OF PACIFICORP'S TRANSMISSION SYSTEM AND GATEWAY SOUTH

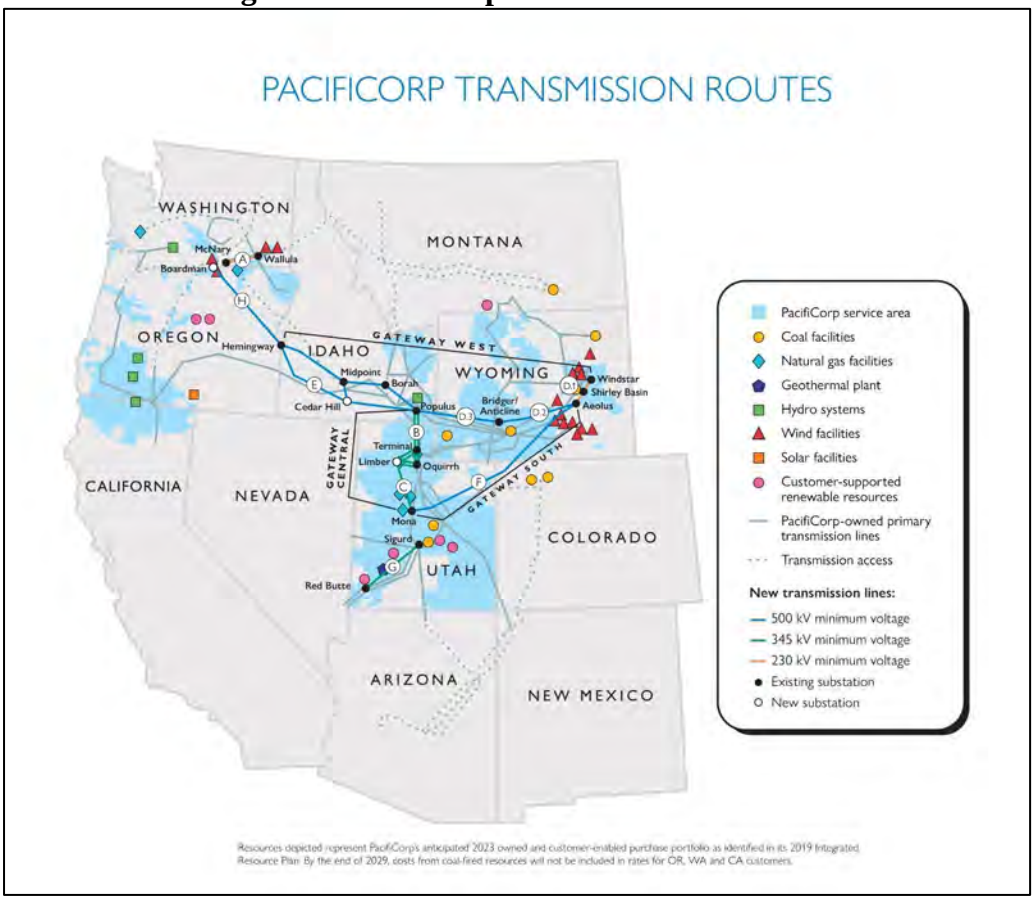
Q. Please provide a brief overview of the purpose of PacifiCorp's transmission system.

A. PacifiCorp's transmission system is designed to reliably transfer affordable electric energy from a broad array of generation resources to loads both within the Company's balancing authority areas (BAAs) and beyond, including other BAAs that with which PacifiCorp interconnects, and to participants in the California Independent System Operator's (CAISO) Western Energy Imbalance Market (WEIM).

Q. Please briefly describe PacifiCorp's transmission system.

A. As seen in Figure 1 below, PacifiCorp owns and operates over 17,770 miles of transmission lines ranging from 46-kilovolt (kV) to 500 kV across multiple western states. PacifiCorp serves nearly two million customers with approximately 620,000 customers located in Oregon.

Figure 1 - PacifiCorp's Transmission Routes

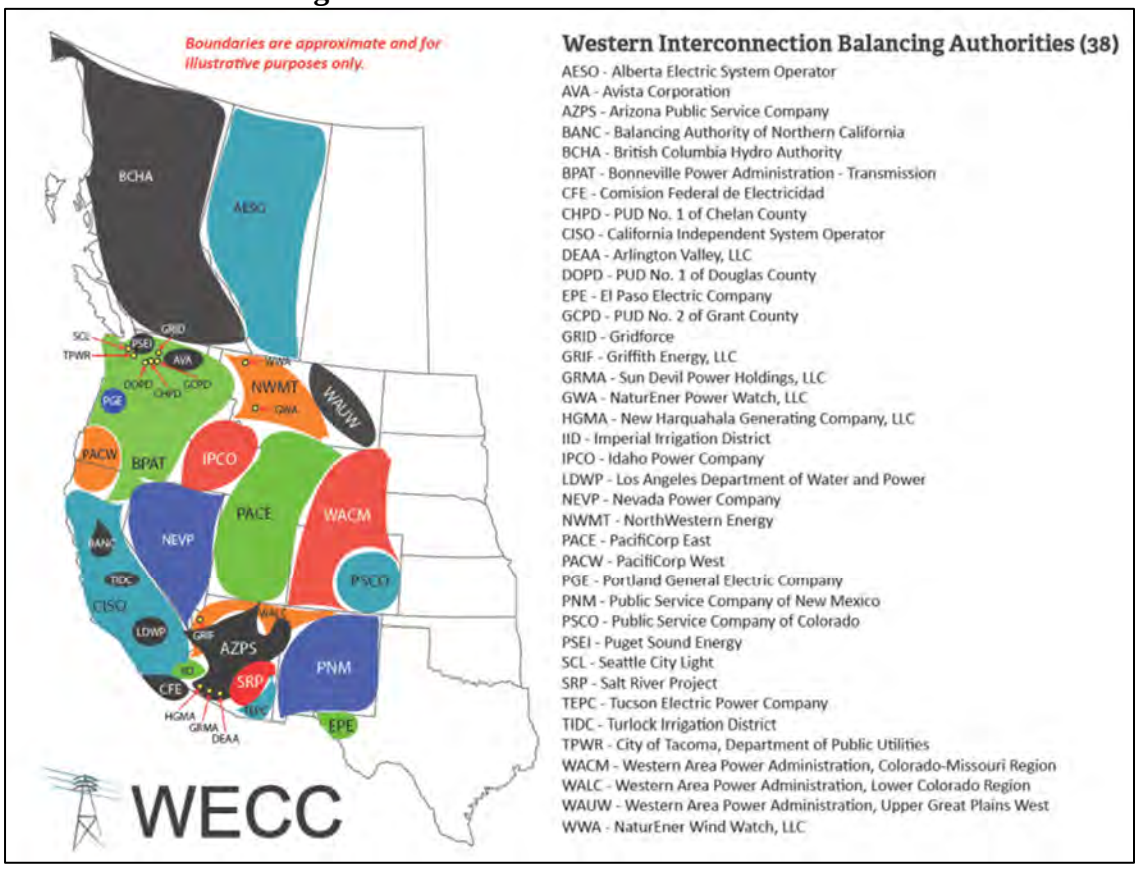


Q. What are balancing authorities and BAAs?

A. A balancing authority is the entity responsible for maintaining balance of load, generation, and interchange in a specific area, and supports interconnection frequency in real time. BAAs include all the generation, transmission, and loads within a specific metered region.

PacifiCorp is a balancing authority and manages two BAAs: PacifiCorp East (PACE) BAA and PacifiCorp West (PACW) BAA. The PACW BAA includes interconnections with the Bonneville Power Administration (BPA), northern points of CAISO, and other utilities in California, Oregon, and Washington. The PACE BAA interconnects with utilities in the intermountain west and southwest in the states of Wyoming, Idaho, and Utah, and provides access to the southern portion of the CAISO. As a balancing authority, PacifiCorp manages the production and consumption of electricity in these areas, by ensuring that there are adequate available generation resources or electricity transfers from other BAAs to meet the load demand. As seen in Figure 2 below, there are 38 BAAs in the Western Interconnection.

Figure 2 - Western Interconnection BAAs



Q. How does PacifiCorp operate its two BAAs?

A. PacifiCorp separately balances each BAA for energy and load. To optimize dispatch for the benefit of customers, PacifiCorp dispatches generation across both BAAs to serve load across the entire system. Deliveries of energy over PacifiCorp's transmission system are managed and scheduled in accordance with the Federal Energy Regulatory Commission's (FERC) requirements. The flexibility of PacifiCorp's integrated transmission system provides options for optimizing dispatch to serve load while providing additional reliability during planned or unplanned generation outages. PacifiCorp also provides transmission service across both BAAs, meaning that a transmission customer can purchase transmission service from any point in one BAA to the other BAA for a single tariff rate.

Q. Please describe the Energy Gateway Transmission Expansion.

A. In 2007, PacifiCorp launched the Energy Gateway Transmission Expansion (Energy Gateway), a multi-year strategy to add approximately 2,000 miles of new transmission lines across the West. After over a decade of planning, the Company completed construction of Gateway South (Segment F of Energy Gateway) in 2024.[1] Through December 31, 2024, PacifiCorp spent $5.4 billion on Energy Gateway projects and $4.8 billion, including allowance for funds used during construction (AFUDC), had been placed in-service.[2] Figure 3 below provides an overview of the Energy Gateway generally, and Gateway South and Gateway West specifically:

[1] *See, e.g.*, PacifiCorp's 2025 Draft Integrated Resource Plan (IRP), Volume I at 83-90 (Dec. 31, 2024), *available at*: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/2025_DRAFT_IRP_Vol.1.pdf.
[2] *E.g.*, https://www.pacificorp.com/transmission/transmission-projects/energy-gateway.html.

Figure 3 - Energy Gateway Transmission Expansion Overview

Q. Please describe Gateway South.

A. Gateway South includes the following elements:

- A 416-mile, high voltage 500 kV transmission line from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah.
- Rebuilding certain 345 kV transmission facilities in and around the Mona and Clover substations in Utah.
- Two new series compensation stations.

- Expansion of the Aeolus, Anticline, and Clover substations along with modifications to the Mona substation.
- Additional shunt capacitors at Aeolus, Anticline, Clover, Bonanza (Utah), Riverton, and Mustang (Wyoming) substations.
- Additions and modifications to various remedial action schemes, voltage controllers, and control schemes necessary to ensure protection and control of the grid after integration of Gateway South.

IV. CUSTOMER BENEFITS OF PACIFICORP'S TRANSMISSION SYSTEM

Q. Can you summarize the benefits that Oregon customers will receive from Gateway South?

A. Yes. Gateway South will provide significant benefits to PacifiCorp's Oregon customers over its expected 65.5-year operational life. These benefits include:

- Improved reliability and decreased congestion, especially when compared to alternative transmission scenarios;
- Satisfaction of NERC-required reliability requirements and FERC-required generator interconnection and transmission service requests;
- Reduction of power losses by allowing for interconnection of up to approximately 2,030 megawatts (MW) of cost-effective resources (expected to be comprised entirely of wind resources);
- Reduced customer exposure to more expensive market purchases;
- Increased amount of electricity that can be exported from eastern Wyoming by up to 1,700 MW;

- Increased System Operating Limit (SOL) from approximately 1,800 MW to 2,400 MW on the Aeolus West path, increasing the delivery of cost-effective Wyoming wind resources to Oregon customers by way of the Jim Bridger West path;
- Reduced curtailment of wind resources—including Rock Creek I and II—from added transmission capacity; and
- The ability to interconnect both Rock Creek I and II and deliver energy from these cost-effective resources to Oregon customers.

I discuss several of these benefits in the sub-sections below.

A. Resource Diversity and Dispatch Benefits

Q. Please describe how PacifiCorp's transmission system benefits Oregon customers.

A. The unique geographic footprint of PacifiCorp's transmission system, including over 17,770 miles of transmission lines, allows the Company to take advantage of efficiencies and economies of scale from both a planning and operational perspective due to, among other things, retail load characteristics and variable resource diversity. For example, PacifiCorp's transmission system provides over 200 interconnections with adjacent transmission provider BAAs, as well as access to regional energy market hubs in Washington, the California-Oregon Border, Utah, the Four Corners area, and Arizona.

The geographic diversity, access to adjacent transmission providers and BAAs, and access to regional energy market hubs allow PacifiCorp to economically dispatch units across its system and transfer energy from other systems as facilitated by the Company's participation in the WEIM. This expansive footprint ensures that

PacifiCorp is uniquely situated to access some of the nation's most cost-effective resources to serve customer load.

Q. What resources are Oregon customers able to access from PacifiCorp's transmission system?

A. Currently, PacifiCorp owns or has under contract approximately 5,154 MW of wind resources, 3,615 MW of solar resources (with an additional 550 MW of collocated storage), 1,200 MW of hydroelectric resources, and 523 MW of existing or committed standalone storage resources in its generation portfolio.[3] This amounts to over 10 gigawatts of renewable and low variable cost resources. The Company's transmission system is the backbone that provides access to this rich resource diversity, to the benefit of our Oregon customers.

Q. Are there additional benefits you would like to discuss?

A. Yes. Since PacifiCorp operates two BAAs as a collective transmission system, it can use resources that are geographically remote to meet system requirements in each individual BAA. This allows the Company to engage in the most economic dispatch of its generation portfolio to lower costs for all customers. Gateway South, amounting to well over 400 miles of incremental transmission line in the region, further facilitates these benefits.

Q. Are investments across the system necessary to maintain PacifiCorp's transmission system?

A. Yes. The ability to flexibly use a diverse set of energy resources depends significantly on the strength and reliability of PacifiCorp's transmission system to connect those

[3] *E.g., PacifiCorp's 2025 Draft IRP,* Volume I at 114-121.

resources to the PacifiCorp retail customers in all six states. Transmission system outages and other real-time operation constraints place additional burden on the remainder of the multi-state transmission system as corrective actions plans are implemented to maintain compliance with NERC and Western Electricity Coordinating Council (WECC) reliability standards. Increasing PacifiCorp's transmission system capacity enhances reliability, allows more generation to interconnect to serve customer load, and provides flexibility in meeting mandatory reliability standards.

Q. Do investments in PacifiCorp's transmission system provide other benefits to customers?

A. Yes. Transmission system investments also enhance the resiliency of the electrical grid, improving its ability to withstand the impacts of major events such as wildfire and extreme weather. These improvements can reduce the number of customer outages and improve restoration times following such events.

Q. Are reliability benefits easily quantifiable?

A. No. Reliability is, essentially, the absence of system disruptions, and as a result it is difficult to reasonably quantify or estimate the quantitative benefits of reliability investments. Please refer to the Direct Testimony of Company witness John Tsoukalis for more discussion on reliability considerations.

B. <u>Interconnection and Transmission Service Requests Benefits</u>

Q. Can you discuss the Company's need for Gateway South?

A. Yes. In response to nearly 2,500 MW of transmission and interconnection service requests, PacifiCorp executed 13 contracts with third-party customers that require construction of Gateway South or the Aeolus-to-Bridger/Anticline 500 kV transmission project in Wyoming (Gateway West). This includes a transmission service

agreement that requires construction of Gateway South to provide 500 MW of firm point-to-point (PTP) transmission service beginning by the contract start date of January 1, 2025. As an update, the transmission service customer has requested a one-year delay in starting service. PacifiCorp is evaluating that delay to ensure it does not impact lower queued projects. If the delay is granted, the transmission customer is required to pay for taking the delay and the capacity available due to the delay will be posted on PacifiCorp's Open Access Same-Time Information System (OASIS) page for use by other customers as short-term firm transmission.

Q. How did PacifiCorp conclude that it could not serve these requests with its existing transmission system?

A. The short answer is due to reliability concerns. Here, interconnecting additional generation in eastern Wyoming, or serving just the 500 MW PTP customer, 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 violate NERC and WECC reliability standards, degrade the reliability of service to other customers, and negatively impact utilities across the Western Interconnection.

Q. Could PacifiCorp have reliably served these customers with a much smaller upgrade if it had not relied upon PacifiCorp's long-term plan for the upgrade solution?

A. No. This conclusion is based on an evaluation that PacifiCorp performed in response to stakeholders in the Company's 2019 Integrated Resource Plan (IRP) proceeding before the Utah Public Service Commission.[4]

In that proceeding, stakeholders asked PacifiCorp to provide information about how its preferred portfolio and system costs might be impacted if Gateway South was removed from the preferred portfolio. In response, PacifiCorp explained that, even if Gateway South is not constructed, it is unrealistic to assume that PacifiCorp would not be obligated to construct any transmission system upgrades in eastern Wyoming to accommodate these FERC-jurisdictional requests for interconnection and transmission services.[5]

Q. Can you provide additional detail on this analysis?

A. Yes. First, we assumed there was no plan to construct Gateway South and Gateway West Segment D.1 (Segment D.1).[6] Next, we 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. We continued to add projects and evaluate individual incremental interconnection requirements one at a time, until we identified each request that depended on Gateway South and Segment D.1.

[4] *In re PacifiCorp's 2019 Integrated Resource Plan*, Utah Docket No. 19-035-02.
[5] *See* Follow-on Gateway West Without Gateway South Analysis (May 29, 2020) (PAC/401).
[6] Segment D.1 is a new 230 kV transmission line and a rebuild of an existing 230 kV line between the Shirley Basin and Windstar substations, which is part of the Gateway South project.

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 many additional 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,[7] and the Company would have achieved only 814 MW of incremental transfer capability. 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 these analyses?

A. My primary conclusion is that PacifiCorp's identification of Gateway South and Segment D.1 as the upgrade solutions 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

[7] Serial Queue Build Out with No Long-Term Transmission Plan Study Report at 5 (June 26, 2020) (PAC/403, Vail/5).

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 PTP request. 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. The Company's study indicated that, focusing only on the 500 MW PTP transmission service request, PacifiCorp would need to construct, at minimum, a 230 kV transmission line by the end of 2023, at a cost in excess of $1 billion.[8]

Q. Does the obligation under the OATT to construct additional transmission apply only to a 230 kV transmission line, rather than the proposed 500 kV transmission line from Aeolus to Mona/Clover?

A. No. A 230 kV line would be required to serve the 500 MW transmission service request, and *only* that request. Because PacifiCorp has far more than a single request for OATT services in Wyoming (13 in total), PacifiCorp could not serve all the requests with only a 230 kV line.

Q. To summarize, what interconnection and transmission service request benefits does Gateway South provide?

A. For these OATT service requests specifically, Gateway South provides substantially more transfer capacity and interconnection capability, for only a modest increase in

[8] PAC/403, Vail/3-5.

Company investments, compared to alternatives that would have been required to meet its federal requirements. These benefits are particularly critical in this case because Rock Creek I and Rock Creek II are two of the projects that can interconnect because of Gateway South.

C. Reliability Requirements

Q. Can you discuss specific benefits provided by Gateway South?

A. Yes. Gateway South alleviates several reliability concerns caused in part by the addition of approved resources being constructed in eastern Wyoming. The increased transmission capacity provided by Gateway South also provides greater customer benefits compared to the next best alternative transmission scenario, despite being similar in cost.

Q. Can you discuss these reliability concerns?

A. Yes. Gateway South will enhance the Company's ability to comply with applicable reliability standards imposed by WECC and NERC. At the time the Company evaluated reliability issues surrounding the 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 the 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. However, PacifiCorp expects sustained load growth to continue for the foreseeable future.[9]

Q. Can you provide more detail on how these reliability studies support Gateway South?

A. Yes. Confidential Exhibit PAC/402 is a study that demonstrates the reliability issues that are created by the addition of FERC-jurisdictional resources, and that are resolved by Gateway South and Segment D.1. Reliability issues arise because the existing transmission system cannot transmit the incremental Wyoming wind resources that seek to interconnect to PacifiCorp's system.

For example, 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 up to Point of Rocks substation in Sweetwater County

[9] *E.g., PacifiCorp's 2025 Draft IRP,* Volume I at 112.

under certain system outage conditions.[10] These outages, along with thermal overload, also result in voltages below acceptable limits around the Echo Springs substation in Carbon County.[11] This 230 kV transmission path, which has already demonstrated reliability concerns, serves several large customers in Wyoming whose service could be potentially impacted in absence of the proposed transmission.

Q. Did the Company consider other alternatives to Gateway South?

A. Yes. In addition to the studies discussed above, PacifiCorp evaluated three alternative scenarios to address the needs that Gateway South meets.

Q. Can you describe the first alternative?

A. Yes. During Northern Grid's 2018-2019 biennial study cycle,[12] Deseret Power, on behalf of itself and four other Utah stakeholders, requested an economic study to evaluate up to two 345 kV transmission lines as a lower-cost alternative to the 500 kV Gateway West and Gateway South lines.[13]

Northern Grid's Planning Committee performed the requested study, which evaluated an alternative that included one 345 kV line with bundled conductors from Aeolus to Anticline (138 miles) and two 345 kV lines with bundled conductors from Anticline to Populus (approximately 198 miles each), along with other supporting mitigation such as transformers and shunt capacitors at different substations.[14]

[10] Gateway South (Aeolus – Clover 500 kV Line Analysis) at 5-6 (Oct. 1, 2020) (PAC/402, Vail/6-7).
[11] PAC/402, Vail/6.
[12] Then the Northern Tier Transmission Group (NTTG), an unincorporated association of entities that promotes coordinated and transparent transmission planning and facilitates compliance with FERC Order 1000, which required transmission planning and reliability standards for the Pacific Northwest and Intermountain West.
[13] NTTG 2018-2019 Draft Final Regional Transmission Plan at 69 (Sept. 18, 2019), *available at* https://www.northerngrid.net/private-media/documents/2018-2019_NTTG_Plan.pdf (NTTG Regional Transmission Plan).
[14] NTTG Regional Transmission Plan, Appendix E at 93.

These analyses indicated that the alternative lines were less beneficial than the Gateway West and Gateway South projects for several reasons. First, the alternative lines would reduce the number of resources that could be interconnected to eastern Wyoming by approximately 1,100 MW compared to Gateway West and Gateway South. This reduced capacity would result in increased flows on transmission exiting in Wyoming and would force generation to increase in Utah, dispatching it without consideration of economics.[15]

Second, the alternative lines showed additional reliability issues on the transmission system between Rock Springs and Monument, and between Populus and Terminal, which would have to be mitigated to comply with relevant reliability standards. This would result in additional cost burdens. Unlike Gateway South, the alternative lines do not provide an adequately diverse path for PacifiCorp's network loads.

Third, securing permits and rights-of-way for the two proposed 345 kV lines could require an additional 12 to 15 years.[16] The Planning Committee also noted that PacifiCorp already secured all rights-of-way and was currently building Gateway West, scheduled for energization at that time in 2020.

Due to these limitations and because the proposed 345 kV option had no sponsor, the project was not considered in the Regional Transmission Plan for the 2018–2019 biennial study cycle.

[15] NTTG Regional Transmission Plan, Appendix E at 92.
[16] NTTG Regional Transmission Plan, Appendix E at 92.

Q. Can you explain the second alternative?

A. Yes. In response to an order in Utah Docket No. 19-035-02, which indicated that "PacifiCorp excluded from its modeling a potential alternative transmission expansion case evaluated by NTTG in its 2018-2019 Regional Transmission Plan that demonstrated sufficient merit to warrant PacifiCorp's further study,"[17] 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 in Northern Grid's study.[18] This analysis identified significant reductions in interconnection capabilities with this alternative.[19]

Q. Was the system performance significantly different between the two alternatives?

A. Yes. Technical studies demonstrated that by replacing Gateway South with 345/230 kV alternative transmission improvements between Aeolus – Anticline – Populus, 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, through Idaho, terminating in Utah would be reduced from 1,700 MW to 814 MW due to Path C (Idaho to Utah) transmission path limitations. This alternative would also require ignoring Path C 2,250 MW transmission path restrictions specific to the underlying 138 kV system 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.

[17] Docket No. 19-035-02, Order at 22 (May 13, 2020).
[18] *See* PAC/401.
[19] PAC/401, Vail/6.

Q. Can you summarize what these alternative analyses demonstrate?

A. These analyses led the Company to conclude that Gateway West and Gateway South were more beneficial. In order to grant only the 500 MW transmission service request, the Company would be required to construct a 230 kV line at a cost of approximately $1 billion. However, to grant both the transmission and interconnection service requests, consistent with the Company's OATT, the Company would be required to construct the functional equivalent of Gateway South and Gateway West.

Q. Will PacifiCorp's transmission customers share in the costs of these transmission lines?

A. Yes. PacifiCorp's transmission customers pay for transmission and ancillary services through the Company's transmission formula rate included in PacifiCorp's OATT.[20]

Q. Do PacifiCorp's Oregon retail customers receive an offsetting revenue credit for a portion of the transmission revenue received under PacifiCorp's OATT?

A. Yes. A portion of PacifiCorp's transmission revenues are credited to the Company's state retail customers. This ensures that PacifiCorp recovers its transmission expenditures and that both wholesale and retail customers only pay their proportional share of the Company's transmission system.

[20] *In re PacifiCorp's Application for Formula Rates*, 143 FERC ¶ 61,162 (May 23, 2013) (letter order establishing formula rate).

D. Interconnection of Rock Creek I and II

Q. Do Gateway South and Gateway West increase the amount of generation that can be interconnected and delivered across the Company's transmission system?

A. Yes. Both allow the Company to interconnect an additional 2,030 MW of generation resources in eastern Wyoming. Due to their geographic location, the Company anticipates that the entirety of this capacity will be comprised of wind resources.

Overall, this creates approximately 1,700 MW of incremental transfer capability from eastern Wyoming (Aeolus) to the central Utah energy hub (Mona/Clover), as well as increasing the SOL on the Aeolus West path that goes from eastern Wyoming to central Wyoming and then west through Bridger West path.

Q. What is the difference between interconnection generation capacity, transfer capability, and SOL?

A. Interconnection generation capacity refers to the amount of generation (MW) that could be interconnected reliably to the transmission system in an area. This amount can vary depending on the amount of load in the area, and the transmission available to move additional generation out of the area.

This is different than Total Transfer Capability (TTC) and SOL. TTC is defined as the "amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions."[21] Applied here, TTC can be thought of as the maximum amount of electric power that

[21] NERC, "Glossary of Terms Used in Reliability Standards (V.0 - Draft 4)" (Jan. 7, 2005), *available at:* https://www.nerc.com/pa/Stand/Version%200%20Relaibility%20StandardsRD/Glossary_Clean_1-07-05.pdf.

could be reliably transmitted by Gateway South from eastern Wyoming (Aeolus) to central Utah (Clover), under various system conditions.

On the other hand, SOL is defined as "All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states."[22] SOL is the transfer capability that can vary across transmission lines or paths due to differing system conditions caused by seasonal loads, generation availability, transmission outages, or others, that can result in exceeded facility ratings or voltage concerns for certain outages. For example, depending on the load or generation profiles in the area, a particular transmission outage may present different reliability issues in the summer compared to the winter season, creating different summer and winter season SOLs for the same transmission line.

Q. Do Rock Creek I and II require Gateway South to interconnect?

A. Yes. The interconnection study and agreements for both Rock Creek I and Rock Creek II discussed in Company witness Jeffrey M. Wagner's Direct Testimony, make clear that Gateway South must be in service for the projects to interconnect.

Q. Do Rock Creek I and II require Gateway South to deliver their output to load?

A. Yes. The Gateway South line has been identified as a required facility as part of the transmission service request study that designates both Rock Creek I and Rock Creek II as network resources.

[22] NERC, "Glossary Definition: System Operating Limit" (Jun. 28, 2021), *available at:* https://www.nerc.com/pa/Stand/Project%20201509%20Establish%20and%20Communicate%20System%20Op/2015-09%20Proposed%20NERC%20Glossary%20Term%20System%20Operating%20Limit.pdf.

In addition, PacifiCorp's Wyoming area transmission system includes 1,360 MW of newly installed wind projects and 2,608 MW of existing wind generation in the area. In absence of Gateway South, all 3,968 MWs of these wind resources will have to use the Gateway West Segment D.2, which is part of the Aeolus West path which has a rating of 1,800 MW without Gateway South and 2,400 MW with Gateway South.[23] Without the Gateway South line, which adds additional transmission capacity of 1,700 MW, significant curtailments of wind generation would occur under both normal as well as outage system conditions. This means that without Gateway South, the Company would have to significantly curtail generation from both Rock Creek I and II.

Q. Do either Rock Creek I or II interconnect directly to Gateway South?

A. No. None of the 12 generation interconnection projects that make up the 2,030 MW of capacity provided by Gateway South and Gateway West will directly interconnect to either transmission line. Each of these 12 resources, including Rock Creek I and II, will interconnect to PacifiCorp's existing 115 kV and 230 kV transmission system, that will be reinforced by Gateway South and Gateway West. Rock Creek II is interconnected to the 230 kV portion of the Aeolus substation, located in eastern Wyoming where the Energy Gateway South line originates, and where the 525/230 kV transformer is located.

[23] *See* Aeolus West Transmission Path FAC-013 Assessment (Feb. 11, 2020) (Exhibit PAC/404); s*ee also* Winter 2024-2025 Aeolus West and TOT 4B System Operating Limits (Aug. 26, 2024) (Exhibit PAC/405).

Q. Would Rock Creek I and II be able to interconnect to PacifiCorp's transmission system without the incremental interconnection generation capacity, transfer capability, and SOL provided by Gateway South?

A. No. Rock Creek I and II, in total, have almost 600 MW of nameplate capacity. By any measure, these are significant generation resources. PacifiCorp's existing transmission system could not: (a) interconnect these resources; (b) export electricity generated by these resources beyond Wyoming; (c) avoid significant curtailment of these resources; nor (d) satisfy FERC interconnection requirements and NERC reliability standards. Gateway South addresses each of these concerns.

V. CONCLUSION

Q. Can you summarize your recommendations for the Commission?

A. I recommend the Commission conclude that Gateway South provides immediate and substantial benefits for Oregon customers, and that this transmission line was necessary to interconnect Rock Creek I and II to PacifiCorp's system.

Q. Does this conclude your testimony?

A. Yes.

REDACTED
Docket No. UE 470
Exhibit PAC/205
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Rick T. Link

Mitchell 2026 TAM Direct Testimony

May 2026

REDACTED
Docket No. UE 450
Exhibit PAC/100
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Ramon J. Mitchell

April 2025

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ATTACHED EXHIBITS

Exhibit PAC/101—Oregon-Allocated Net Power Costs

Exhibit PAC/102—Net Power Costs Report

Confidential Exhibit PAC/103—Update to Renewable Energy Production Tax Credits

Exhibit PAC/104—Net Power Costs Step Log

Exhibit PAC/105—Non-Precedential Step Log

Exhibit PAC/106—February 27, 2025 Notice Letter

Confidential Exhibit PAC/107—2020 Benchmark Report

Confidential Exhibit PAC/108—Set 1_ Prior Modeling Adjustments

Confidential Exhibit PAC/109—Set 2_ Prior Modeling Adjustments

Confidential Exhibit PAC/110—Set 3_ Prior Modeling Adjustments

Confidential Exhibit PAC/111—Overview of the DART

Confidential Exhibit PAC/112—Brattle EDAM Benefits Study

Confidential Exhibit PAC/113—Aurora Optimization Logic

Confidential Exhibit PAC/114—Four-Year Wind into the Future

Exhibit PAC/115—2023 TAM Company Direct

Exhibit PAC/116—2024 TAM Company Direct

Exhibit PAC/117—2025 TAM Company Direct

I. INTRODUCTION AND QUALIFICATIONS

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 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) filings.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the Oregon Public Utility Commission (Commission), as well as commissions in California, Idaho, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

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

A. I present the Company's proposed 2026 Transition Adjustment Mechanism (TAM). Specifically, my testimony:

- Defines NPC and summarizes the content of the filing;
- Provides an overview of historical NPC forecasts as proposed by different parties;

- Provides an overview of historical production tax credit (PTC)—and associated wind—forecasts;
- Describes the NPC forecast in the 2026 TAM compared to actual NPC in calendar year (CY) 2024;
- Describes changes the Company is proposing in this TAM filing, and references changes made in prior TAMs; and
- Provides an update on provisions from prior Commission orders.

Q. Please identify the other Company witnesses supporting the 2026 TAM.

A. Three additional Company witnesses provide testimony supporting the Company's filing. James C. Owen, Vice President, Environmental & Energy Resources, provides testimony supporting the coal fuel costs and supply included in the 2026 TAM. Vijay Singh, Senior Organized Markets Analyst, presents the Company's proposed revisions to the Western Energy Imbalance Market (WEIM) inter-regional transfer benefit forecasting models. Judith M. Ridenour, Pricing and Cost of Service Specialist, presents the Company's proposed prices and tariffs and provides a comparison of existing and estimated customer rates.

III. SUMMARY OF THE COMPANY'S 2026 TAM FILING

Q. Please explain NPC.

A. NPC are the sum of fuel expenses, wholesale purchase power expenses, allowances and wheeling expenses, less wholesale sales revenue.

Q. How does the TAM relate to NPC?

A. In the 2017 TAM Order, the Commission described the TAM and its purpose as follows:

> 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 TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the forecasts is of significant importance to setting fair, just and reasonable rates. Our goal, therefore, is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.[1]

Q. Please explain how the Company derives NPC.

A. The Company derives NPC for a future test period based on a forecast using Aurora, which is a production cost model. Aurora simulates the operation of the Company's power system on an hourly basis and provides an hourly forecast of NPC for the future test period.

Q. Which version of Aurora was used to prepare this initial filing?

A. The Aurora version used to prepare this initial filing was version 15.0.1016.[2] No other version of Aurora is assured to be able to identically reproduce the NPC proposal in this initial filing.

Q. Has the Company proposed any modeling changes in the 2026 TAM?

A. Yes. The Company proposes the modeling changes enumerated below, in addition to all modeling changes proposed in the 2023, 2024 and 2025 TAM:

- An updated WEIM benefits methodology.
- An Extended Day-Ahead Market (EDAM) benefits methodology.
- The Rolling Hills wind facility is now included in the total-Company NPC simulation to ensure an accurate portrayal of actual operations, with a post

[1] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 2-3 (Dec. 20, 2016).
[2] Specifically, Aurora version 15.0.1016.9052 released on December 13, 2024.

simulation mark-to-market adjustment to remove the resource from rates, consistent with the methodology used in the Power Cost Adjustment Mechanism (PCAM).

- Market sales capacity limits are updated to remove double counting of hedges.

Q. Did the Company provide advance notice to the parties regarding the modeling changes proposed in this case?

A. Yes. In compliance with the TAM Guidelines, the Company provided notice of changes to the Company's modeling of NPC in the 2026 TAM. This notice was provided on February 27, 2025, and is included as Exhibit PAC/106.

Q. What non-precedential changes from prior TAMs have been carried forward into this TAM?

A. All changes proposed in the 2023, 2024 and 2025 TAM are implemented in this filing. Please refer to Confidential Exhibit PAC/108,[3] Confidential Exhibit PAC/109,[4] Confidential Exhibit PAC/110[5] and Confidential Exhibit PAC/111[6] for support of changes proposed in the preceding TAM filings and please refer to Exhibit PAC/105 for the NPC impact of those changes. To the extent that support is not found in the above referenced exhibits, then please refer to Exhibit PAC/115, Exhibit PAC/116, or Exhibit PAC/117 for the necessary information.

Q. What inputs were updated for this filing?

A. The Company updated all inputs to the 2026 TAM, including system load, wholesale

[3] Day-ahead/real-time (DA/RT) percentile modifier; DA/RT volume component correction; Average of averages market capacity limits.
[4] Average of averages market capacity limits; Market capacity limits applied to all markets.
[5] Hedging requirements; Unspecified purchased power; Incomplete source data.
[6] Day-ahead/real-time (DA/RT) price component; DA/RT volume component; DA/RT volume component correction.

sales and purchase contracts for electricity, natural gas and wheeling, the official forward price curve (OFPC) market prices for electricity and natural gas, fuel expenses, and the characteristics and availability of the Company's generation facilities.

Q. What is the date of the OFPC the Company used in this filing?

A. The Company's filing uses the OFPC dated December 31, 2024.

Q. Will the Company continue to update the OFPC through the pendency of this proceeding?

A. Yes. In accordance with the current TAM Guidelines, the Company's reply update will incorporate the most recent OFPC that is available at the time the update is prepared. The November indicative update will incorporate an OFPC from within nine days of the filing, and the November final update will incorporate an OFPC from within seven days of the filing. This ensures that the most up-to-date market price information is used in the forecast, providing a more accurate estimate of NPC for the test period.

Q. Please provide background on the Company's 2026 TAM filing.

A. The TAM is an annual filing that the Company makes to update its NPC in rates and to set the transition adjustments for direct access customers. Along with the forecast NPC, the 2026 TAM also includes test period forecasts for renewable energy PTCs.

Q. What is the total-Company NPC in the TAM for CY 2026?

A. The forecast total-Company NPC for CY 2026 is approximately $35.96 per megawatt-hour ($/MWh).[7] This is approximately $6.38/MWh or 15 percent lower

[7] $2.420 billion. See Exhibit PAC/101, Mitchell/1, line 36.

than the total-Company 2024 actual NPC of approximately $42.34/MWh.[8] Further details on the total-Company NPC forecast for 2026 are provided in Exhibit PAC/102.

Q. What is the decrease to Oregon-allocated NPC and the impact to Oregon rates?

A. As shown in Exhibit PAC/101, there is a decrease to Oregon-allocated NPC—relative to the 2025 NPC forecast, not the 2024 actuals—of approximately $0.07/MWh[9] and an increase in PTCs (decrease to rates) of approximately $0.422 million. After adjusting for the variance from loads, the 2026 TAM results in a decrease to Oregon rates of approximately $0.59/MWh.[10] As explained in the testimony of Company witness Ridenour, the 2026 TAM results in an overall average rate decrease of 0.5 percent, or $10.4 million (Oregon-allocated). Unless otherwise specified, references to NPC or PTCs throughout my testimony are expressed on an Oregon-allocated basis.

IV. TAM ACCURACY

A. NPC Forecast Accuracy

Q. Please describe the relevance of NPC forecast accuracy in the TAM.

A. **First**, in the 2004 GRC (docket UE 170), the Commission adopted a TAM with annual NPC updates (i.e., forecasts) and stated the following, in the order:[11]

> We find that the TAM proposed by PacifiCorp, with annual updates, most closely meets the requirements established in Order No. 04-516. The purpose of the TAM is not to promote direct

[8] $2.692 billion.
[9] $8.1 million increase without and before accounting for change in customer usage.
[10] $10.4 million. The $/MWh based on load at system level, prior to line losses.
[11] *In the Matter of Pacific Power & Light Company, d/b/a PacifiCorp, Request for a General Rate Increase in the Company's Oregon Annual Revenues*, Docket No. UE 170, Order No. 05-1050 at 21 (Sep. 28, 2005).

> access […] Rather, the TAM is to capture costs associated with direct access, and *prevent unwarranted cost shifting*.[12]

Second, in the 2017 TAM Order, the Commission stated the following:

> *[T]he accuracy of the [NPC] forecasts is of significant importance to setting fair, just and reasonable rates*. Our goal, therefore, is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.[13]

Q. Setting aside the impacts to the financial health of the Company—resulting from lack of recovery of prudently incurred power costs—how are customers impacted by inaccuracy in the NPC forecasts?

A. As it concerns direct access, transition adjustments in the TAM are calculated by comparing the weighted market value of energy used to serve direct access loads with the cost-of-service rate under the customers' specific energy-only tariff. The Commission approved an annual NPC update to ensure that both the weighted market value and the cost of service are calculated for the same period using the same data. To the extent that downward adjustments in the annual NPC update decrease the accuracy of the overall NPC forecast, this decreases the cost-of-service rate and therefore artificially increases the transition adjustment credits—or decreases the transition adjustment charges—paid to, or received from, direct access customers. Ultimately, the result is cost shifting between cost-of-service customers and direct access customers. This is the unwarranted cost shifting that the annual NPC forecast in the TAM is intended to prevent.

[12] *Id [emphasis added]*.
[13] Docket No. UE 307, Order No. 16-482 at 2-3.

Q. Have the NPC adjustments proposed by parties in the TAM succeeded in advancing the Commission's goal of unwarranted cost shifting, or accurate NPC forecasts?

A. No.

Q. Please elaborate.

A. The Company has used Aurora to forecast NPC for calendar years 2022, 2023, 2024, 2025 or 2026 across all six states in its service territory. After analysis of all parties' NPC proposals across this time period, a few noteworthy facts present themselves.

First, on no occasion has the Company's *proposed* Aurora NPC forecast exceeded the actual NPC.[14] In other words, any inaccuracy in Aurora's NPC forecast has been to the benefit of customers and to the detriment of the Company.

Second, on no occasion has any non-Company party (including Staff), in any proceeding, in any of the Company's six states, proposed a NPC forecast that was more accurate than the Company's proposed Aurora NPC forecast.[15] All non-Company parties' proposed NPC forecasts since the implementation of Aurora have always been lower than the Company's Aurora NPC forecast. This was also an issue before the Company implemented Aurora.[16]

Q. What are the consequences of non-Company parties persistently recommending adjusting the Company's proposed NPC forecasts downward?

A. While the Company has incorporated principled adjustments over the years, nearly all the adjustments that are proposed by non-Company parties decrease NPC—and all

[14] After adjusting all proposals proportionally for mandated changes made in the November final update.
[15] *Id.*
[16] *Id.*

cumulative adjustments proposed by non-Company parties decrease NPC, resulting in a process that almost always leads to NPC in rates (baseline NPC) that are lower than the Company's NPC proposal.[17]

Q. Are these consequences of inaccurate and artificially low NPC unique to the Company's usage of Aurora to produce NPC forecasts since CY 2022?

A. No: (1) this problem has always existed and parties consistently propose adjustments that create an asymmetric risk on the Company;[18] and (2) despite the mounting factual evidence that parties' adjustments have not resulted in a more accurate NPC forecast than the Company—combined with baseline NPC that are near perpetually under-forecast,[19] there remains a persistent challenge from these NPC recommendations that ultimately reduce the Company's NPC proposal. That is to say, parties continue to recommend downward adjustments to the Company's NPC proposals even though it is almost certain that their actions will decrease the accuracy of the NPC forecast.[20]

Q. How have these dynamics played out on a numerical basis?

A. **First**, please refer to Figure 'OR Aurora'[21] below which calculates the level—or counterfactual level—of all parties' TAM NPC proposals in the last couple years,

[17] *Id.*
[18] Reference Figure 'OR TAM;' *See e.g., In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, PAC/600, Graves/4 (Feb. 2020); *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 399, PAC/1500, Wilding/9-10 (Jul. 2022); *In the Matter of PacifiCorp, dba Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400, PAC/600, Mitchell/69 (Jun. 2022); *In the Matter of PacifiCorp, dba Pacific Power, 2024 Transition Adjustment Mechanism*, Docket No. UE 420, PAC/400, Mitchell/16 (Jul. 2023); *In the Matter of PacifiCorp, dba Pacific Power, 2024 Transition Adjustment Mechanism*, Docket No. UE 420, PAC/800, Mitchell/5 (Aug. 2023).
[19] Reference Figure 'OR Aurora'.
[20] After adjusting all proposals proportionally for mandated changes made in the November final update.
[21] Similar figures are available for NPC recommendations presented in the Company's other service territories, by intervenors or associated consultants in this TAM.

which are all, without exception, more inaccurate than the Company's proposals. Were Figure 'OR Aurora' extended backwards through time, the result would be the same in nearly all years since the annual NPC update was incorporated into the Company's TAM, as best exemplified by Figure 'OR TAM'.

Second, please refer to Figure 'OR TAM' which shows Oregon TAM specific under-forecasts over 17 consecutive years—since test period 2008. With the one exception of test period 2016, the data incontrovertibly demonstrate the outcome of the prevailing dynamic within the Oregon TAM, explained above, wherein proposed adjustments do not achieve and are ultimately counter to the Commission's goal of accurate NPC forecasts.

Figure OR Aurora

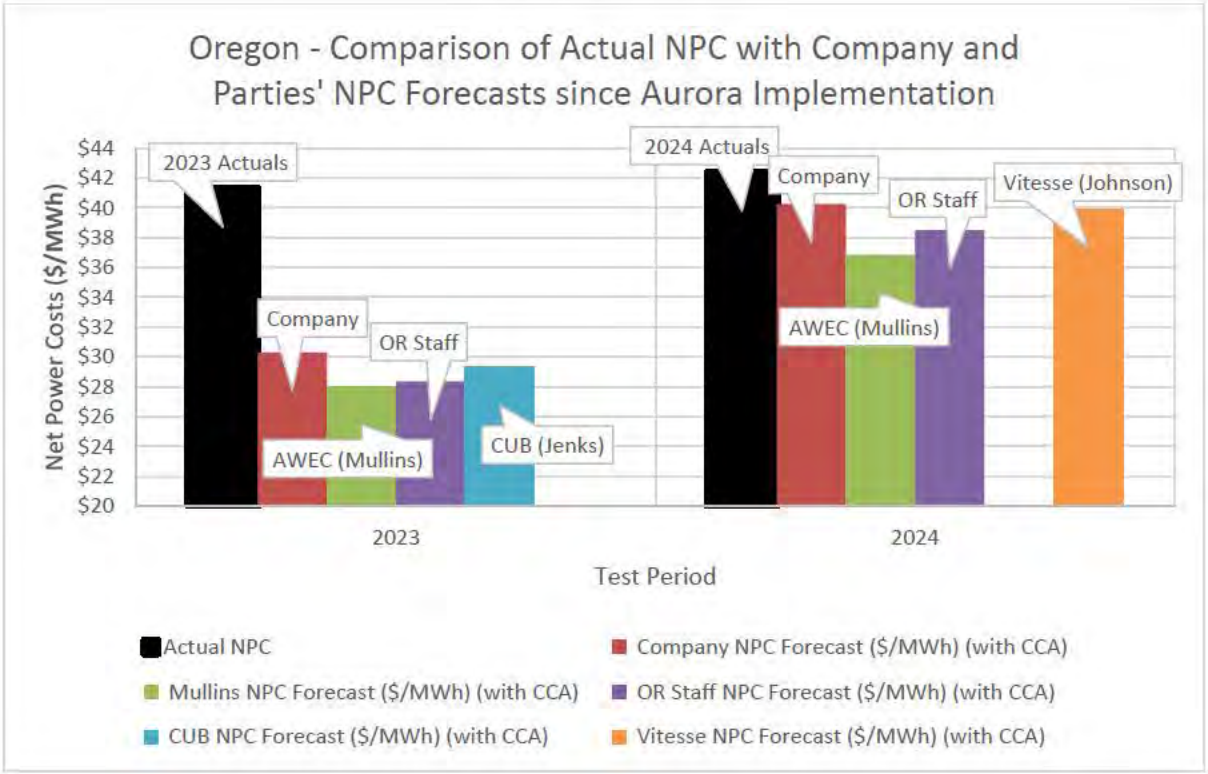
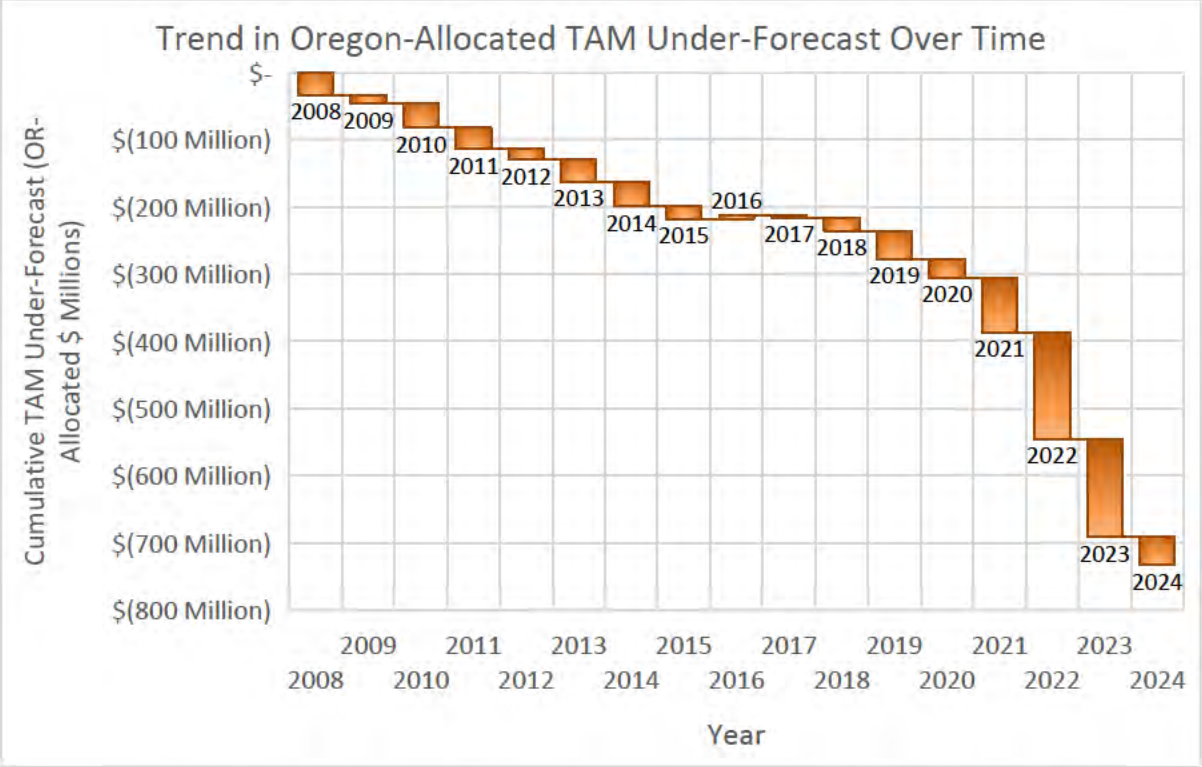


Figure OR TAM



Q. Is it not the case that these NPC forecasts are normalized and intended to represent a normal (average) test period, and therefore it is to be expected that the NPC forecasts are less than actuals during a period of rising NPC?

A. This is not a general rate case. The "TAM is an annual filing in which [the Company] projects the amount of [NPC] to be reflected in customer rates for the following year […] The TAM effectively removes regulatory lag for the [Company]."[22] Since the intent of the TAM is to reduce regulatory lag, and since the NPC forecast from the TAM will never apply to any period but the test period, the forecast is not and cannot be intended to be an "average" or "normal" test period forecast. The NPC forecast should reasonably reflect the test period's actual NPC.

[22] Docket No. UE 307, Order No. 16-482 at 2-3.

Q. Do these persistent inaccuracies in the NPC forecasts create inaccurate price signals for customers?

A. Yes. Setting aside cost recovery issues, this disconnect between the forecast and actuals results in inaccurate price signals sent to customers that are considering opting out of cost-of-service and moving to direct access. This ultimately shifts costs between customers who remain on cost-of-service and customers that move to direct access.

B. PTC Forecast Accuracy

Q. Like the persistent under-forecast of power costs, is there a persistent over-forecast of PTC revenues?

A. Yes. Since the new wind resources associated with Energy Vision 2020 (EV 2020)—along with the associated Energy Gateway West Segment D.2 transmission line (Gateway West)—all achieved their commercial operation date in CY 2021,[23] the Company has persistently over-forecasted PTC revenue (to the benefit of customers and to the detriment of the Company) for all the recorded history after EV 2020.

In the 2024 TAM the Company raised this over-forecasting issue[24] and the response from parties was as follows: (1) Staff acknowledged the Company's history of over-forecasting PTCs, and associated wind, yet went on to propose a further ***increase*** to the PTC forecast;[25] and (2) AWEC ignored the Company's testimony on the over-forecasting issue and also proposed a further increase to the PTC forecast.[26]

[23] PACIFICORP, *Energy Vision* 2020, https://www.pacificpower.net/about/innovation-environment/energy-vision-2020.html (last visited Mar. 26, 2025).
[24] Docket No. UE 420, PAC/100, Mitchell/41-42.
[25] Docket No. UE 420, Staff/600, Chipanera/2-5.
[26] Docket No. UE 420, AWEC/100, Mullins/16.

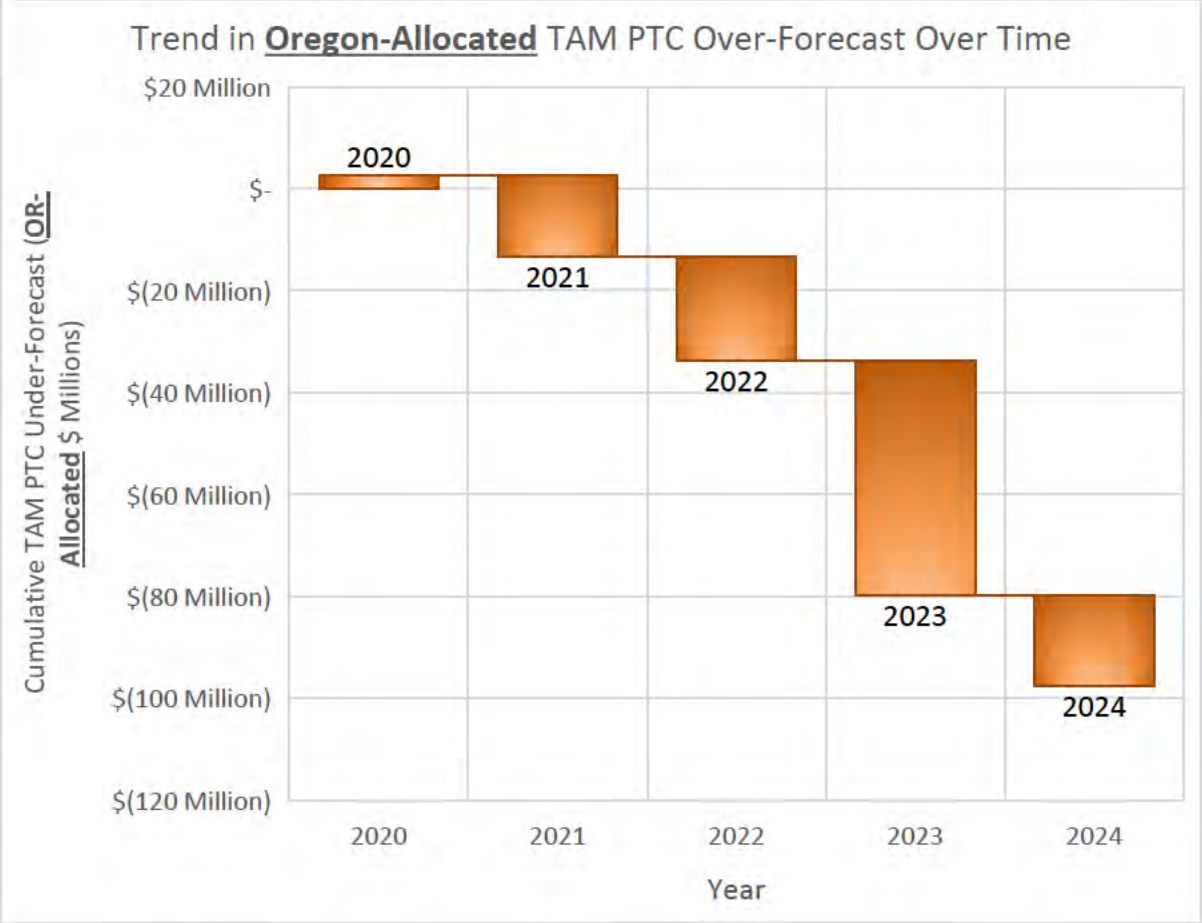
Then, in the 2025 TAM—filed at the beginning of 2024—CY 2023 PTCs were observed to be also over-forecasted in the TAM, yet Staff again proposed an increase to the PTC forecast.[27] These positions taken by these parties advance the perception of non-Company parties having no interest in TAM forecast accuracy.

Q. What do the most recent CY 2024 data show?

A. Again; the PTCs (and associated wind forecasts) are still over-forecast, by approximately $18 million Oregon-allocated in CY 2024. Please refer to Figure 'OR PTC' for the persistent impact of over-forecasting PTCs since EV 2020 completed in CY 2021.

[27] Docket No. UE 434, Staff/100, Kim/15.

Figure OR PTC



Q. Why are the PTCs so persistently over-forecasted, as shown above?

A. The Company's wind forecasts in the TAM have been routinely over-forecasted each year since EV 2020, inclusive of CY 2024 actual wind generation. Notwithstanding, and as mentioned above, parties continually advocate to increase the PTC forecast, or the underlying wind forecast, and drive this persistent over-forecast issue.

Q. Has the Company's modeling improvement efforts remedied the issue?

A. Only partly. As mentioned above, the wind forecast in the 2024 TAM was again over-forecasted (as predicted during the pendency of the 2024 TAM).[28] However, the

[28] Docket No. UE 420, PAC/100, Mitchell/42, Table 6.

metrics have improved. Across the past four years of EV 2020 wind generation, the wind generation shows an over-forecast each year—as illustrated below in Figure 'Wind Over-Forecast'—with an average over-forecast of 11.7 percent. In 2024, the wind generation over-forecast was 8.3 percent which is the lowest over-forecast percentage across the four-year history, as displayed below in Table 'Wind Over-Forecast'.

In this 2026 TAM, the data indicate a higher potential for a more accurate wind, and associated PTC, forecast. Specifically, the 2026 aggregate wind forecast capacity factor is within 0.2 percent of the 2021-2024 four-year average wind forecast capacity factor. Please refer to Confidential Exhibit PAC/114 for further details.

Figure Wind Over-Forecast

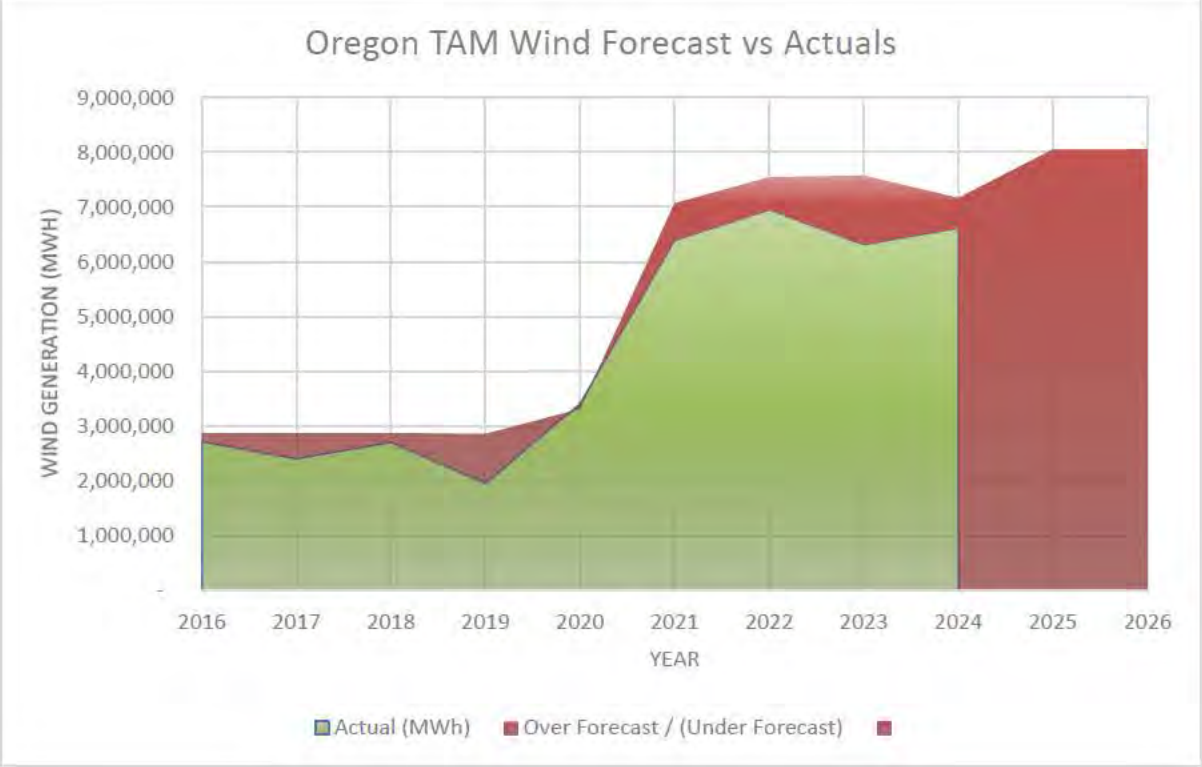


Table Wind Over-Forecast

Period	Actual (MWh)	Forecast (MWh)	Over Forecast / (Under Forecast)
2026		8,053,318	
2025		8,050,943	
2024	6,615,280	7,165,282	8.3%
2023	6,311,595	7,573,819	20.0%
2022	6,949,590	7,545,687	8.6%
2021	6,389,267	7,064,532	10.6%
2020	3,404,418	3,312,773	(2.7%)
2019	1,952,733	2,857,240	46.3%
2018	2,700,550	2,874,335	6.4%
2017	2,400,316	2,874,335	19.7%
2016	2,711,238	2,869,840	5.8%
Total	**26,430,440**	**29,908,029**	**13.2%**

Q. Is the Company proposing an adjustment for this persistent PTC over-forecast issue in this 2026 TAM?

A. No.

V. NPC VALIDATION

Q. Is $35.96/MWh a reasonably accurate forecast for total-Company NPC?

A. Yes. 2024 Actual NPC is $42.34/MWh. In 2026, as compared to 2024:

(1) 2026 Pacific Northwest summer and winter peak power prices **decrease** by 2 percent and Desert Southwest summer and winter peak power prices **increase** by 45 percent;

(2) 2026 Pacific Northwest summer and winter natural gas prices **increase** by 111 percent and Rocky Mountain region summer and winter natural gas prices **increase** by 120 percent; and

(3) Resource adequacy requirements demonstrate capacity deficits that must be cured with incremental supply-risk based power hedges—discussed in further detail below.

These fundamentals indicate that 2026 total-Company NPC would be higher than 2024 *actual* total-Company NPC, all else equal. However, commodity price increases are offset by: (1) new battery energy storage systems which allow for intra-day price arbitrage opportunities and provide dispatchable capacity, ultimately lowering NPC; (2) an estimated increase of approximately one million megawatt-hours (MWh) in Company owned wind generation; (3) increased coal supply relative to 2024; and (4) the removal of the dispatch adder associated with the Washington Climate Commitment Act (CCA). Altogether, these market fundamentals changes—and more—combine to reduce NPC as compared to the actuals observed in 2024.

Q. Why are summer and winter prices particularly critical when comparing prices?

A. Summer and winter peak periods are periods of high customer demand and stressed system conditions. Higher power prices in those periods will produce NPC that is substantially higher relative to any decrease in NPC that may result from lower prices in spring and fall months, which have light load and relatively mild system conditions.

VI. DISCUSSION OF NPC CHANGES IN THE TAM

Q. Please generally describe the changes in this 2026 forecast NPC compared to 2024 actual NPC.

A. The decrease in 2026 forecast NPC relative to 2024 actual NPC is driven by continued in-model over optimization of market sales, which artificially increase

wholesale sales revenues, more optimal timing of market purchases resulting from the introduction of battery energy storage systems, additional coal supply relative to 2024, and the construction/acquisition of additional wind resources. This decrease is slightly offset by increased commodity prices for wholesale electricity, natural gas and coal. However, the net impact remains a decrease.

Tables 'NPC Prices,' 'NPC Energy,' and 'NPC Dollars,' illustrate the changes in total-Company NPC by category from the 2024 actual NPC to the 2026 forecast NPC.

Table NPC Prices

Net Power Cost Reconciliation			
	2024 $/MWh	**2026 $/MWh**	**Change**
NPC Components			
Wholesale Sales Revenue	54.31	51.90	(2.42)
Purchased Power Expense	73.62	47.43	(26.19)
Coal Fuel Expense	28.94	31.43	2.49
Natural Gas Fuel Expense	33.75	38.58	4.83
Wheeling and Other Expense	21.82	21.74	(0.08)
Total NPC	**42.34**	**35.96**	(6.38)

Table NPC Energy

Net Power Cost Reconciliation		
	MWh	**$/MWh**
2024 Actual Load	**63,591,135**	**42.34**
Change to Load:		
Wholesale Sales Increase	(1,243,907)	
Purchased Power Increase	3,575,254	
Coal Generation Increase	1,582,576	
Natural Gas Generation Decrease	(1,537,492)	
Other Generation Increase	1,340,571	
Total Change to Net System Load	**3,717,001**	
2026 Forecast Load	**67,308,136**	**35.96**

Table NPC Dollars

Net Power Cost Reconciliation		
	($ millions)	**$/MWh**
2024 Actual NPC	**2,692**	**42.34**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	(59.8)	
Purchased Power Expense	(369.8)	
Coal Fuel Expense	95.1	
Natural Gas Fuel Expense	22.5	
Wheeling and Other Expense	40.0	
Total Change to NPC	**(272.0)**	
2026 Forecast NPC	**2,420**	**35.96**

Q. Please explain the decrease in purchased power expense and the increase in wholesale sales revenue.

A. Despite the increase in market prices and requirements for meeting resource adequacy needs, the introduction of battery energy storage systems allows for more optimal timing of market purchases. As an example, energy is purchased during the solar

hours (trough load) at low prices and then used to serve load during the evening hours (peak load), thereby avoiding purchases that would otherwise have been made during the higher priced evening hours. Additionally, the removal of the dispatch adder—related to the CCA—in the NPC forecast contributes to the decreased purchased power, since the greenhouse gas allowance costs are accounted for as purchased power in the 2024 actual NPC. For wholesale sales revenue, Aurora produces unrealistically high wholesale sales revenue,[29] and the increase in wholesale sales revenues reflect this difference between recent 2024 actuals and the current 2026 NPC forecast.

Q. Please explain the increase in coal fuel expense and the increase in natural gas fuel expense.

A. Additional coal supply, relative to 2024, allows for increased coal generation and associated coal fuel expense which is—on average—lower priced than market purchases. Furthermore, with the introduction of battery energy storage systems and additional coal supply, gas generation—higher priced than coal on average—decreases, but the increase in natural gas market prices produces a net increase in natural gas fuel expense.

Q. Please explain the increase in wheeling and other expense.

A. Wheeling expenses reflect historical wheeling expenses supporting recent actual purchased power volumes, which have increased over time. Additionally: (1) consistent with the PCAM, the Rolling Hills wind facility is assigned a market value, since Oregon customers do not pay for any of the plant's revenue requirement; and

[29] Please refer to Confidential Figure 'Market Sales Down,' Confidential Exhibit PAC/108 and Confidential Exhibit PAC/109.

(2) the variable EDAM grid management charge is booked as a wheeling expense. These items are discussed in detail below.

VII. MODELING IMPROVEMENTS

Q. In addition to the modeling improvements proposed in the 2023 TAM, the 2024 TAM and the 2025 TAM, has the Company incorporated any additional modeling improvements into this year's TAM?

A. Yes. The Company is proposing the following modeling improvements:

- An updated WEIM benefits methodology.
- An EDAM benefits methodology.
- The Rolling Hills wind facility is now included in the total-Company NPC simulation to ensure an accurate portrayal of actual operations, with a post simulation mark-to-market adjustment to remove the NPC benefit of the resource from rates, consistent with the methodology used in the PCAM.
- Market Sales Capacity Limits are updated to remove double counting of hedges.

A. WEIM Benefits Methodology

Q. What change is the Company proposing for WEIM benefits?

A. Please refer to the direct testimony of Company witness Vijay Singh for details. The Oregon (OR)-allocated NPC impact of this change is a decrease of $8.8 million[30].

B. EDAM Benefits Methodology

Q. What is the EDAM?

A. The EDAM is a market that allows for limited[31] regional, centralized scheduling and commitment of resources on a day-ahead basis. This market aims to enhance the

[30] Decrease to total-Company NPC of $32.9 million.
[31] Based on the number of EDAM participants, which will be two (2) at implementation.

efficiency and reliability of electricity supply by optimizing the use of resources across a broader geographic area. EDAM participation can help utilities like the Company manage their net power costs more effectively and integrate renewable energy sources more efficiently.

The current WEIM optimizes the energy imbalances throughout the West by transferring energy between participants in 15-minute and 5-minute intervals throughout the day. The EDAM builds on this real-time market by extending optimization to hourly intervals on a day-ahead basis while keeping the 15-minute and 5-minute optimizations.

Q. Since the EDAM is scheduled for implementation in 2026, how has the Company incorporated this market into this 2026 NPC forecast?

A. As an initial matter, there are three foundational elements of the EDAM that must be outlined before any discussion of EDAM benefits.

Q. What is the first foundational element?

A. **First**. It is only after one-third of the year has passed, in May 2026—assuming no delays—that the EDAM is anticipated to be implemented with the only participants being the Company and the California Independent System Operator (CAISO). In October 2026, Portland General Electric (PGE) is then scheduled to join the EDAM. After PGE, no further participants are scheduled for EDAM entrance in 2026. This dilutes EDAM benefits due to the limited EDAM time to be experienced in 2026, along with the lengthy learning curve required to become familiar with and proficient in this new market.

Q. What is the second foundational element?

A. **Second**. On implementation, the transfer capability within the EDAM will be one transmission path between PacifiCorp West and the CAISO, which is the same transmission path used today in the WEIM. It is anticipated that this paradigm will continue when PGE joins the EDAM. That is to say, the transmission paths used today in the WEIM to connect the Company and PGE will be the same transmission paths used to connect the Company and PGE in the EDAM. This dilutes EDAM benefits because these are not new connections between entities. Since transmission capacity is static, one of the functional impacts of the EDAM upon implementation will be a movement of benefits out of the intra-day horizon of the WEIM and into the day-ahead horizon of the EDAM.

Since the EDAM benefits shown in this 2026 NPC forecast are incremental to "business as usual," which includes the current WEIM, and since the WEIM benefits in this forecast have not been adjusted downwards to account for cannibalization of WEIM benefits by the EDAM, the EDAM benefits in this 2026 NPC forecast are present both in the calculation described further below, and in the WEIM benefits that currently exist. Presented further below are only the portion of EDAM benefits that are *not* currently embedded in the WEIM benefits. Quantification of the portion of EDAM benefits that *are* currently embedded in the WEIM benefits has not been performed.

Q. What is the third foundational element?

A. **Third**. Although the conceptual market design is known, the way EDAM participants—including the Company—will operate within the confines of the actual

market design across pivotal market elements is mostly unknown. Examples of these mostly unknown, pivotal market elements are: (1) amount of transmission donated; (2) use of price taker self-schedules versus standard economic bids; (3) potential restrictions on market based commitment; (4) methods to mitigate the misalignment between gas delivery versus power delivery start times; (5) interaction with third party utilities that exist within an EDAM entity's balancing authority area; (6) market bidding strategies; (7) impact of market power mitigation rules; and (8) multiple other issues. Furthermore, as it concerns the operations of non-Company EDAM participants, many of these pivotal market elements of operation will never be fully known.

Q. How do these three foundational elements above relate to incorporating EDAM benefits into this 2026 NPC forecast?

A. If the Company's system and associated footprint were smaller in size, it may have been possible to simulate a rough and generally accurate approximation of a simplistic, bifurcated, dual market system, with both the EDAM and the pre-existing bilateral markets co-existing—however this is not the case. The EDAM cannot currently be modeled by the Company within a production cost model—at bare minimum—until the market accumulates some history of operations. However, the Brattle Group, Inc. (Brattle), a well-respected consulting practice, has in its possession, preliminary information on tentatively speculative market operations expectations as it concerns the Company, the CAISO, PGE and many other balancing authority areas—provided to Brattle by those balancing authority areas. Brattle used that utility-confidential data to simulate EDAM benefits incremental to the current

status quo for CY 2030.[32] The Company has pro-rated those EDAM benefits to CY 2026 and applied the resulting amount as an out-of-model adjustment.

Q. Please elaborate.

A. Brattle modeled PacifiCorp's EDAM benefits to be $359 million total-company in 2030. These benefits are incremental to the status quo of the bilateral markets and the WEIM. Along with those benefits, the total annual gigawatt-hour (GWh) transfers between each of the 10 assumed EDAM participants, as of 2030 (displayed below in Confidential Figure 'EDAM Transfers') were derived. From these values, the Company extracted transfers between the Company and both the CAISO and PGE to prorate the benefits downward to CY 2026, and then further prorated the benefits downwards to account for each entity's EDAM implementation date.

Confidential Figure EDAM Transfers

[redacted]

Q. What is the decrease to NPC resulting from this EDAM benefits methodology?

A. The Oregon (OR)-allocated NPC impact of EDAM benefits before accounting for the EDAM grid management charge, and *without accounting for the EDAM benefits embedded in the WEIM benefits*, is a decrease of [redacted].[33] The EDAM grid

[32] Confidential Exhibit PAC/112.
[33] [redacted]

management charge is expected to be [redacted][34] in 2026. Therefore, the Oregon-allocated net impact of the EDAM on NPC, without accounting for the EDAM benefits embedded in the WEIM benefits, is forecasted to be a decrease of [redacted].[35]

C. Rolling Hills Wind

Q. How is the Rolling Hills wind facility treated in the PCAM which focuses on *actual* NPC?

A. The Rolling Hills wind facility is not in Oregon customer rates.[36] However, the resource physically exists and electrically provides power to Oregon customers. To account for this discrepancy, the PCAM—as it concerns actual NPC—takes the generation from the Rolling Hills wind facility and multiplies it by then-prevailing market prices at the Four Corners power trading hub (i.e., a mark to market valuation).

Q. How *was* the Rolling Hills wind facility previously treated in the TAM which focuses on *forecast* NPC?

A. Since the Rolling Hills wind facility is not in Oregon customer rates, the resource was not included in the NPC simulation. Therefore, the NPC forecast in the TAM created a counter-factual scenario through which generation from the Rolling Hills wind facility did not exist, but instead is fictionalized as replaced by some increase in market purchases or some decrease in market sales or some increase in other Company generation.

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[34] [redacted]

[35] [redacted]

[36] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2009 Renewable Adjustment Clause Schedule 202*, Docket No. UE 200, Order No. 08-548 at 20-21 (Nov. 14, 2008).

Q. Why was this discrepancy between the PCAM and the TAM—as it concerns Rolling Hills—eliminated?

A. Since Rolling Hills physically exists and electrically provides power to Oregon customers, its benefits are therefore included in *actual* NPC. However, since Oregon customers do not pay any costs associated with Rolling Hills, these benefits must be removed from *actual* NPC after-the-fact. The PCAM accomplishes this removal of benefits through a spreadsheet mark to market adjustment that occurs after the system dispatch has taken place.

However, this treatment of Rolling Hills in actual NPC was inconsistent with the treatment in the forecast NPC. In the forecast NPC, the removal of benefits occurred before the system dispatch took place. This resulted in a "*mark to system*" adjustment in which the generation from Rolling Hills is backfilled with some combination of an increase in market purchases, a decrease in market sales or an increase in other Company-owned generation.

This disparate treatment means that conceptually the base NPC can never be equal to actual NPC.[37] Therefore, the base NPC is: (1) factually inaccurate without this adjustment; and (2) contrary to parties' goal[38] of achieving an accurate NPC forecast.

Q. How was this discrepancy between the PCAM and the TAM—as it concerns Rolling Hills—eliminated?

A. Identical to the way the system operates, Rolling Hills is simulated as a wind resource

[37] Note: statistically, there is some de minimis chance of the base NPC and the actual NPC coincidentally matching.
[38] See Section IV(A) above, titled 'NPC Forecast Accuracy.'

providing energy to the system in the NPC forecast. Then, after-the-fact the NPC forecast's spreadsheet report takes the generation from the Rolling Hills wind facility and multiplies it by the forecast market prices at the Four Corners power trading hub (i.e., a mark to market valuation). This matches the treatment of the resource in the PCAM and allows for a more accurate NPC forecast relative to the PCAM.

Q. What is the NPC impact of this modeling change?

A. The NPC impact of this modeling change is an increase to Oregon-allocated NPC of $1.1 million.[39]

D. Non-Precedential Modeling Improvements

Q. How has the Company treated the non-precedential modeling improvements from the 2023, 2024 and 2025 TAM?

A. All non-precedential modeling improvements from the 2023, 2024 and 2025 TAM are included in this filing. Please refer to Confidential Exhibit PAC/108,[40] Confidential Exhibit PAC/109,[41] Confidential Exhibit PAC/110[42] and Confidential Exhibit PAC/111[43] for supporting testimony. To the extent that support is not found in the above referenced exhibits, then please refer to Exhibit PAC/115, Exhibit PAC/116, or Exhibit PAC/117 for the necessary information.

[39] Increase to total-Company NPC of $4.1 million.
[40] Day-ahead/real-time (DA/RT) percentile modifier; DA/RT volume component correction; Average of averages market capacity limits.
[41] Average of averages market capacity limits; Market capacity limits applied to all markets.
[42] Hedging requirements; Unspecified purchased power; Incomplete source data.
[43] Day-ahead/real-time (DA/RT) price component; DA/RT volume component; DA/RT volume component correction.

Q. In Confidential Exhibit PAC/108, you present prior testimony from the 2024 TAM supporting the use of the Day-Ahead/Real-Time (DA/RT) percentile modifier and the average of averages market caps methodology. Are there any updates to that testimony?

A. Yes. First, Confidential Figure 6 in Confidential Exhibit PAC/108 is updated below, with more recent data, as Confidential Figure 'Flat vs Percentile' and illustrates the real, actual, historical DA/RT price component contrasted with a hypothetical flat adder, showing that the data supports the percentile adder as more accurate. Second, Confidential Figure 11 in Confidential Exhibit PAC/108 is updated below, with more recent data, as Confidential Figure 'Market Sales Down' and illustrates the 2026 forecast sales as compared to historical actual sales, showing that the data supports the use of a **minimum** of averages approach and definitively does not support a third quartile of averages approach. Please refer to Confidential Exhibit PAC/108,[44] Confidential Exhibit PAC/109,[45] and Confidential Exhibit PAC/111[46] for further evidentiary detail on these issues.

[44] Day-ahead/real-time (DA/RT) percentile modifier; DA/RT volume component correction; Average of averages market capacity limits.
[45] Average of averages market capacity limits; Market capacity limits applied to all markets.
[46] Day-ahead/real-time (DA/RT) price component; DA/RT volume component; DA/RT volume component correction.

Confidential Figure Flat vs Percentile

Confidential Figure Market Sales Down

E. Market Capacity Limits

Q. Has the Company made any additional changes to the market sales capacity limits calculation?

A. Yes. In addition to the market sales capacity limits modeling improvements incorporated in preceding TAMs, now with the inclusion of simulated hedge volumes in the modeled NPC[47], the Company has removed volumes related to hedges from its market sales capacity limits calculation.

Q. Why is the Company proposing to remove hedge volumes from its market sales capacity limits calculation?

A. Under the previous method, market sales capacity limits were first calculated using historical sales volumes inclusive of sales hedge volumes. Then, second, these limits were reduced by executed sales hedge volumes for the test period, in order to provide for a realistic modeled estimate of spot market sales volumes (i.e., sales in the day-ahead and real-time trading horizons) plus *yet-to-be-executed* sales hedge volumes in the modeled NPC. However, since the modeled NPC is now fully hedged with simulated hedge volumes from the 'Hedging Requirements' modeling update discussed in the 2025 TAM, and reiterated in Confidential Exhibit PAC/110, the modeled market sales volumes in the 2026 forecast NPC now represent only spot market sales volumes. For this reason, the market sales capacity limits *calculation* now includes only spot market sales volumes (i.e., excludes all hedge volumes) in its calculation to avoid potential double counting.

Please refer to Confidential Figure 'Market Sales Down' above, specifically

[47] Introduced in the 2025 TAM. See Confidential Exhibit PAC/110.

the last column labeled "2026 TAM (Average of Averages – Test Period Hedges)," for a visualization of the change to market sales volumes under this method as compared to the "Average of Averages" method, the "Third Quartile of Averages" method, and historical sales. As illustrated, all methods, but for the Company's proposed method, show sales volumes forecasts that are greater than the four-year average sales volume and all methods show sales volumes forecasts that are far greater than any expectation of 2026 sales volumes extrapolated from the downward trend observed in market sales volumes over the past four years.

Therefore, while the accuracy of forecasted market sales volumes has improved relative to prior TAM's, the market sales volumes forecast is still too high.

Q. What is the NPC impact of this modeling update?

A. Removing hedge volumes from the *average of averages* market sales capacity limits calculation results in an Oregon-allocated NPC increase of $3.8 million.[48]

Q. In the 2024 TAM, there was an assertion that market hubs at Mid-Columbia (Mid-C), Palo-Verde (PV) and Four Corners do not require any market sales capacity limits.[49] In addition to the supporting testimony in Confidential Exhibit PAC/108[50] and Confidential Exhibit PAC/109,[51] does the Company have any other evidentiary support to offer?

A. Yes. The Company used the Aurora 2020 benchmarking study (referenced in the

[48] Increase to total-Company NPC of $14.2 million.
[49] *In the Matter of PacifiCorp, dba Pacific Power, 2024 Transition Adjustment Mechanism*, Docket No. UE 420, AWEC/100, Mullins/5 (Jun. 2023); Docket No. UE 420, AWEC/200, Mullins/18 (Aug. 2023).
[50] Day-ahead/real-time (DA/RT) percentile modifier; DA/RT volume component correction; Average of averages market capacity limits.
[51] Average of averages market capacity limits; Market capacity limits applied to all markets.

2025 TAM[52] and provided as Confidential Exhibit PAC/107) as a starting point for testing. The Company then fixed (set as static and known in the model) all historical sales volumes except for real-time sales volumes (i.e., fixed hedge sales volumes to day-ahead sales volumes) and then ran the model to observe the in-model (modeled) system balancing sales, which should be representative of historical real-time sales volumes only, given the aforementioned fixing of all other sales volumes.

Q. Please explain this simulation of real-time sales volumes in further detail.

A. With modeled system balancing sales as a proxy for historical real-time sales there was a need to adjust the DA/RT price component to only account for historical real-time transactions, instead of historical real-time and day-ahead transactions. Furthermore, the DA/RT volume component was adjusted to remove the inferred daily, 25-megawatt (MW) increment block products that represent products from day-ahead trading. Lastly, the market capacity limits were removed in order to assess their relevance.

Q. How do the modeled real-time sales volumes compare with the actual, historical real-time sales volumes?

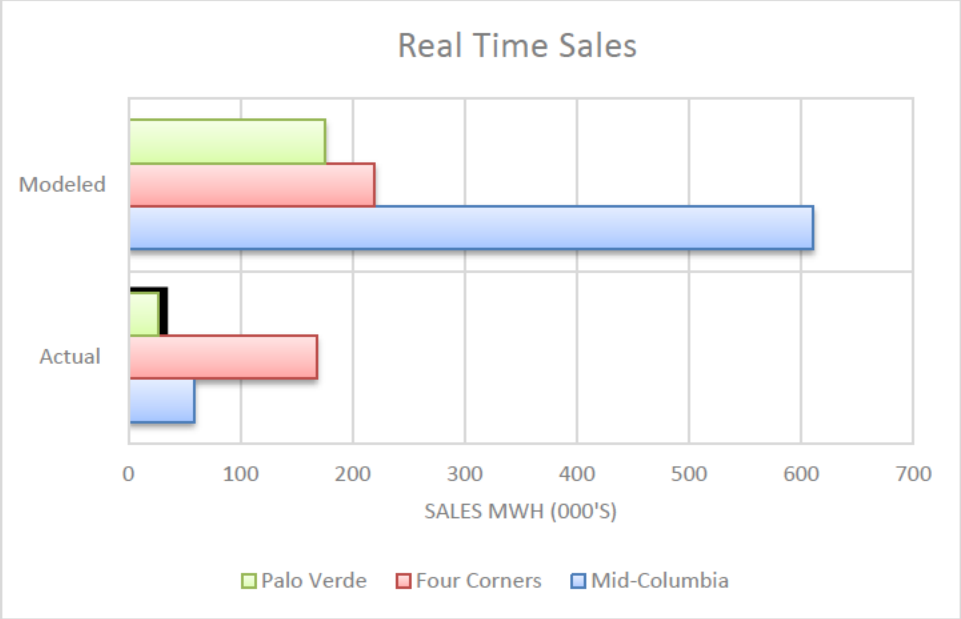
A. Using the Aurora 2020 benchmarking study, the below Table 'RT Sales' and Figure 'RT Sales' show a comparison between modeled real-time sales volumes and historical real-time sales volumes, in 2020, at the Mid-C, PV and Four Corners trading hubs.

[52] *In the Matter of PacifiCorp, dba Pacific Power, 2025 Transition Adjustment Mechanism*, Docket No. UE 434, PAC/106 (Feb. 2024).

Table RT_Sales

2020 Real-Time Sales			
	Actual (MWh)	Forecast (MWh)	Percentage Increase (%)
Mid-Columbia	58,622	610,866	942%
Palo Verde	26,432	175,257	563%$
Four Corners	167,6161	219,509	31%

Figure RT_Sales



As can be seen from Table 'RT Sales,' modeled real-time sales volumes at the Mid-C, PV and Four Corners trading hubs are greater than historical real time sales volumes by percentages of approximately 942 percent, 563 percent and 31 percent respectively. This shows that without market capacity limits at these trading hubs, Aurora over-optimizes system balancing sales volumes. This over-optimization and the consequent overstatement of wholesale sales revenue, as exemplified best in past

PCAMs,[53] necessitates application of market capacity limits to all trading hubs, inclusive of Mid-C, PV and Four Corners.

Q. Do the increased modeled real time sales volumes reflect an expectation of increased market depth in the test period?

A. No. Please refer to Confidential Figure 'Market Sales Down' above. The modeled real-time sales volumes from this test implies market depth that is contrary to the Company's recent experience.

VIII. MODEL INPUT OPTIMIZATION

Q. What is model input optimization in the context of this testimony?

A. Model input optimization is the increasing usage of native Aurora functionality, as and when possible, to reduce model complexity, reduce model size, or reduce model run times.

Q. By what means did the Company achieve model input optimization?

A. Through ongoing consultation with Energy Exemplar, the Company receives an increasingly in-depth understanding of best practices and techniques in modeling NPC as time progresses. These insights are incorporated into the NPC forecast as and when appropriate.

Q. How does model input optimization impact the NPC forecast?

A. By simplifying the model, or using native Aurora functionality, Aurora becomes easier or faster to understand or use. However, because Aurora—solved by Gurobi—

[53] *In the Matter of PacifiCorp, dba Pacific Power, 2023 Power Cost Adjustment Mechanism,* Docket No. UE 439; *In the Matter of PacifiCorp, dba Pacific Power, 2022 Power Cost Adjustment Mechanism,* Docket No. UE 421; *In the Matter of PacifiCorp, dba Pacific Power, 2021 Power Cost Adjustment Mechanism,* Docket No. UE 404.

is based upon a mixed integer-program,[54] using branch and bound techniques,[55] changes in the mathematical problem size or formulation impacts the presence or lack thereof of suboptimality in the model's commitment and dispatch decisions.[56] Consequently, changes to the problem size or formulation result in relatively minor NPC variances.

Q. What Aurora model input optimizations have been implemented in this NPC forecast?

A. There are two. First, Aurora was designed with the ability to directly evaluate any MW based ancillary service product. Explicit ancillary service MW based obligations can be inserted into Aurora's optimization through the Ancillary Services table within the software. This table accepts as input any MW reserve requirements by hour and then appropriately evaluates those requirements within the NPC forecast. Considering this, the Company has moved all ancillary service products into the Ancillary Services table to reduce model complexity, whereas before, a portion of the ancillary services were calculated from resources modeled specifically for that purpose. Second, Aurora was designed with the ability to explicitly resolve supply/demand energy, ramp or capacity deficits. This feature is identical to the function of the Company's emergency purchase (unspecified purchased power) resources,[57] except for that it is native Aurora functionality. Considering this, the Company migrated the

[54] Confidential Exhibit PAC/113.
[55] GUROBI OPTIMIZATION, *Mixed Integer Programming, A Primer on the Basics*, https://www.gurobi.com/resources/mixed-integer-programming-mip-a-primer-on-the-basics/ (last visited Mar. 26, 2025).
[56] LinkedIn, *What are the limitations and challenges of branch and bound?* https://www.linkedin.com/advice/1/what-limitations-challenges-branch-bound-skills-linear-programming (last visited Mar. 26, 2025).
[57] See Confidential Exhibit PAC/110.

modeling of emergency purchases into this feature, whereas before, emergency purchases were acquired from resources modeled specifically for that purpose.

Q. What if any impact did these changes have to the NPC forecast?

A. The Oregon-allocated NPC impact of those two changes is a decrease of $1.1 million.[58]

IX. GATEWAY SOUTH AND NEW WIND

Q. What is Gateway South?

A. The Energy Gateway South transmission line (Gateway South)—a component of the Company's Energy Gateway Transmission Expansion Program—is a 416-mile, high-voltage, 500-kilovolt transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The project was completed in November 2024.

Q. What are the benefits of Gateway South to Oregon customers?

A. Gateway South has the following benefits:

(1) Gateway South enables the integration of more wind onto the system.

(2) Gateway South reduces reliance on market purchases, pursuant to (1).

(3) Gateway South reduces system emissions.

(4) Gateway South increases system reliability.

(5) Gateway South provides NPC and PTC benefits, pursuant to (1) and (2).

Q. What are the NPC and PTC impacts of Gateway South and the associated new/increased wind?

A. Gateway South and the associated new/increased wind production reduces the TAM

[58] Decrease to total-Company NPC of $4.3 million.

by $63 million on an Oregon-allocated basis.[59]

Q. Does the Company have a proposal related to Gateway South and/or the associated new/increased wind in this TAM?

A. Not currently. Based on Commission decisions in other proceedings, the Company may propose updates or adjustments (related to Gateway South and associated wind production) to this TAM in future filings.

X. PRODUCTION TAX CREDITS

Q. Please describe the treatment of renewable energy PTCs in the 2026 TAM.

A. The 2026 TAM includes changes in projected levels of PTCs. Exhibit PAC/103 shows the forecast level of PTCs for 2026 compared to the level of PTCs established in the 2025 TAM. The forecast value of Oregon-allocated PTCs for the 2026 test period is approximately $87.6 million, which is higher than the $87.1 million included in the 2025 TAM, resulting in a decrease to the 2026 TAM of $0.422 million.

Q. How are PTCs calculated for the 2026 TAM?

A. The PTC provides a federal income tax credit for the first 10 years of a renewable energy facility's operation. The PTC is calculated by multiplying the qualifying generation by the applicable PTC rate, and then grossing-up for taxes.

Q. Please describe the capacity, capacity factors, generation and PTCs for the wind projects in the 2026 TAM.

A. As seen in Confidential Table 'Company-Owned Wind Projects Generation and PTC Data' below, on a total-Company basis, the Company-owned wind capacity is

[59] Consisting of $44 million in NPC reductions and $19 million in PTC increase, all on an Oregon-allocated basis.

approximately 2,937 MW and total forecast generation is 8,053,318 MWh. The total tax-adjusted PTCs on an Oregon-allocated basis are $87.6 million.

Confidential Table: Company-Owned Wind Projects Generation and PTC Data

	Total Company				Oregon Allocated		
Plant Name	PTC Value	LGIA Capacity (MW)	LGIA Capacity Factor	Generation (MWH)	Factors CY 2026	CY 2026 Initial Filing	Revenue Requirement *(See Note 1)*
Glenrock	[redacted]	99.0	[redacted]	[redacted]	27.380%	[redacted]	[redacted]
Glenrock III		39.0			27.380%		
Goodnoe		94.0			27.380%		
High Plains		99.0			27.380%		
Leaning Juniper		100.5			27.380%		
Marengo I		156.0			27.380%		
Marengo II		78.0			27.380%		
McFadden Ridge		28.5			27.380%		
Rolling Hills		99.0			27.380%		
Seven Mile		99.0			27.380%		
Seven Mile II		19.5			27.380%		
Dunlap		111.0			27.380%		
Foote Creek I		41.4			27.380%		
TB Flats		500.0			27.380%		
Cedar Springs II		200.0			27.380%		
Ekola Flats		250.0			27.380%		
Pryor Mountain		239.8			27.380%		
Foote Creek III - IV Wind		43.4			27.380%		
Rock Creek 1		190.0			27.380%		
Rock Creek 2		400.0			27.380%		
Rock River 1		50.0			27.380%		
Total Production Tax Credit	$ 241,152,821	2,937.1		8,053,318		$ 66,028,356	$ 87,555,204

Note 1 - Revenue Requirement represents the PTC amount grossed up for the tax rate.

Q. Absent Rolling Hills: (1) why is aggregate wind generation functionally the same between the 2025 TAM and the 2026 TAM; and (2) why are the PTCs functionally the same between the 2025 TAM and the 2026 TAM?

A. **First**, please refer to the Company's direct testimony in the 2024 TAM, in which the same question was posed.[60] **Second**, please refer to Section IV(B) above, titled 'PTC Forecast Accuracy' for further details on the issues with historical wind generation forecasts and associated PTCs, as compared to historical actual data.

[60] Confidential Exhibit PAC/116; Docket No. UE 420, PAC/100, Mitchell/41-42.

XI. ACTUAL OPERATIONS CHANGES

A. Resource Adequacy

Q. What is resource adequacy and how does it benefit customers?

A. Resource adequacy is the planning, typically for the next year or season, by a utility or load serving entity to serve load in a reliable manner. This planning typically includes ensuring an adequate amount of both generation and transmission capacity to serve peak load plus a planning reserve to account for some uncertainty, such as outages, underperformance of resources, and higher-than-forecast loads. Customers benefit from the utility being resource adequate through increased reliability, less market exposure, and more stable power costs.

Q. Does the Company have a formal resource adequacy standard?

A. Yes. The Company currently participates in the non-financially binding phase of the Western Resource Adequacy Program (WRAP), which is a regional reliability planning and compliance program developed by the members of the Western Power Pool to address the emerging reliability needs in the West. The WRAP has created a regional planning standard for which each participant must comply. This planning compliance occurs twice a year in what is called the “forward showing.” Each WRAP participant must show it has adequate generation and transmission capacity to meet its peak load plus a planning reserve margin (PRM) twice a year, once for the summer period (June – September) and once for the winter period (November – March.) The PRM is calculated monthly based on a one-in-ten-year loss of load event. Currently, there are no penalties for failing to comply with the WRAP standard. However, once the program becomes financially binding, WRAP participants who fail to meet the

WRAP standards in their forward showing will face deficiency charges. Each WRAP participant must decide whether to become part of the financially binding WRAP by October 31, 2025.

Q. Please explain how the Company's system is assessed for resource adequacy.

A. From the perspective of WRAP; using monthly peak load forecasts for the 2026 winter and summer seasons, a monthly PRM, ranging between 13.7 percent to 21.9 percent, is added to the monthly peak load forecasts. Note that April, March, and October do not have WRAP planning standards.[61] The monthly peak load plus the PRM is the amount of generation capacity that is needed to comply with the WRAP.

Then, each generation resource in the portfolio is assigned a qualified capacity contribution (QCC), or in other words, how much of the generation capacity can be expected to be available for dispatch during the peak load. The QCC is calculated based on historical performance of the resource or resource type, e.g. wind and solar resource QCCs are evaluated as a resource type in a specific region. To be considered resource adequate the sum of the QCCs of all generation resources must be greater than or equal to the peak load plus PRM each month.[62]

[redacted]

[61] Since peak load is often driven by heating and cooling, these are shoulder months, where demand is relatively lower as compared to the rest of the year.

[62] [redacted]

[redacted]

Q. Please describe the changes that the Company is proposing to its current risk management policy and hedging program / practices.

A. As an initial matter, the Company routinely evaluates its risk management policy to ensure risks are being adequately addressed. The risk management policy is being updated to specifically address two risks. First, is the resource adequacy risk or **supply risk**. The second is the **price risk** or price volatility.

First, the Company must ensure that it meets resource adequacy standards to ensure reliability. Loads by month plus a PRM are compared to allocated capacity contribution values from resources (both owned and contracted) to assess resource adequacy, as mentioned above. [redacted]

In addition to ensuring resource adequacy, the Company will also calculate an average on-peak and off-peak monthly energy position for the purpose of managing price risk to NPC. This is a change from the current method which calculates the capacity position based on the peak load hour within the month. The Company will run a production cost model, then compare the resulting generation to the load forecast (also by month and on/off-peak type) to determine the open position that requires price risk hedging. [redacted]

Q. What is the NPC impact of this change to actual operations?

A. The NPC impact of meeting resource adequacy requirements along with moving from peak load power hedging to average load power hedging is an increase to Oregon-allocated NPC of $9.3 million,[63] as compared to the Company's current hedging practices.

Q. Does PacifiCorp consider this a methodology or modeling change?

A. No, this is not a methodology or modeling change, it reflects changes to hedge policies[64] in actual operations, within the forecast.

XII. COMPLIANCE WITH TAM ORDERS

Q. The 2021 TAM Order describes certain actions that need to be taken prior to the 2026 TAM filing. What are those actions?

A. In Order No. 20-392, the Commission adopted a stipulation reached between the parties.[65] PacifiCorp agreed to the following:

- Performing an informational model run that removes any operational constraints related to the minimum take provisions in the coal supply agreements and uses an average coal price for purposes of dispatching coal plants (to be provided in 15-day workpapers).

Q. Has the Company performed this informational model run?

A. Yes. The informational model run will be provided with the 15-day workpapers for this filing.

[63] Increase to total-Company NPC of $34.5 million.
[64] Hedge policy compliance was introduced as a modeling change in the 2025 TAM.
[65] *See In the matter of PacifiCorp dba Pacific Power's 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 (Oct. 30, 2020).

Q. Were there other items that needed to be followed up on from prior TAM Orders?

A. Yes. The following Table 'Information Requested in Prior Orders' lists the information that was ordered or agreed to in prior TAM Orders and describes where it has been provided:

Table: Information Requested in Prior Orders

Order/Stipulation Requirement	Details
The Commission has disallowed Washington Climate Commitment Act (CCA) costs as a state-specific initiative that is properly allocated to Washington under PacifiCorp's Multi-State Process.	Washington CCA costs are removed from the NPC forecast.
PacifiCorp affirms that the Schedule 296 calculations used to calculate the Consumer Opt-Out Charge, including all supporting work papers, will be provided consistent with the TAM guidelines, 30 days after filing the TAM.	Will be provided in the 30-day workpapers for this filing.
As long as there are coal-fired Jim Bridger units in Oregon rates and they are fueled with coal from Bridger Coal Company, PacifiCorp will provide a copy of the updated annual Bridger Coal Company mine plan along with any alternatives that were also evaluated for PacifiCorp in future TAM filings.	These are provided in PacifiCorp's workpapers associated with this filing.
PacifiCorp agrees to evaluate the calculation of WEIM Benefits and provide a report or proposal for a new or updated calculation including a comparison to Staff's proposed method from the Docket No. UE 434 Opening Testimony. PacifiCorp will provide this report or a new/updated proposal and solicit feedback from the Stipulating Parties at least two months prior to filing the 2026 TAM.	Report/proposal was provided to parties at least two months prior to this filing.

XIII. COMPLIANCE WITH TAM GUIDELINES

Q. Did the Company prepare this filing in accordance with the TAM Guidelines adopted by Order No. 09-274, as clarified and amended in later orders?

A. Yes. The Company has complied with the TAM Guidelines applicable to the initial

filing in a TAM.

Q. Does this filing include updates to all NPC components identified in Attachment A to the TAM Guidelines?

A. Yes.

Q. What workpapers did the Company provide with this filing?

A. In compliance with Attachment B to the TAM Guidelines, the Company provided access to the Aurora model and workpapers concurrently with this initial filing. Specifically, the Company provided the NPC report workbook and the Aurora project.

Q. Did the Company provide a step log of model and input changes describing changes to the Company's modeling or inputs that are not considered a standard annual update?

A. Yes. The Company has provided step logs as Exhibit PAC/104 and Exhibit PAC/105.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 470
Exhibit PAC/206
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Rick T. Link

Zacharia 2027 TAM Direct Testimony

May 2026

REDACTED
Docket No. UE 469
Exhibit PAC/100
Witness: Isaiah M. R. Zacharia

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Isaiah M. R. Zacharia

April 2026

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ATTACHED EXHIBITS

Exhibit PAC/101—Oregon-Allocated Net Power Costs

Confidential Exhibit PAC/102—Net Power Costs Report

Confidential Exhibit PAC/103—Update to Renewable Energy Production Tax Credits

Exhibit PAC/104—Net Power Costs Step Log

Exhibit PAC/105—Non-Precedential Step Log

Exhibit PAC/106—February 27, 2026 Notice Letter

Confidential Exhibit PAC/107—Set 1_ Prior Modeling Adjustments

Confidential Exhibit PAC/108—Set 2_ Prior Modeling Adjustments

Confidential Exhibit PAC/109—Set 3_ Prior Modeling Adjustments

Confidential Exhibit PAC/110—Overview of the DART

Confidential Exhibit PAC 111 – Brattle EDAM Benefits Study

Exhibit PAC/112—2023 TAM Company Direct

Exhibit PAC/113—2024 TAM Company Direct

Exhibit PAC/114—2025 TAM Company Direct

Exhibit PAC/115—2026 TAM Company Direct

Confidential Exhibit PAC/116—Schedule Spreadsheet Method

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or company).

A. My name is Isaiah M.R. Zacharia, and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

Q. Please describe your education and professional experience.

A. I received a Bachelor of Science degree from Portland State University. I have been employed by PacifiCorp since 2022 as a member of the regulatory net power costs group.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the Washington Utilities and Transportation Commission and the California Public Utilities Commission.

II. PURPOSE OF TESTIMONY

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

A. I present the company's proposed 2027 Transition Adjustment Mechanism (TAM) net power costs (NPC). Specifically, my testimony:

- Defines NPC and summarizes the content of the filing;
- Describes the NPC forecast in the 2027 TAM compared to preliminary actual NPC in calendar year (CY) 2025;
- Describes necessary updates the company is proposing in this TAM filing, and references changes made in prior TAMs; and
- Provides an update on provisions from prior orders from the Public Utility Commission of Oregon (Commission).

Q. Please identify the other company witnesses supporting the 2027 TAM.

A. Two additional company witnesses provide testimony supporting the company's filing. Jayson Branch, Senior Vice President, Power Supply, provides testimony supporting the coal fuel costs and supply included in the 2027 TAM. Judith M. Ridenour, Pricing and Cost of Service Specialist, presents the company's proposed prices and tariffs and provides a comparison of existing and estimated customer rates.

III. SUMMARY OF THE COMPANY'S 2027 TAM FILING

Q. Please provide background on the company's 2027 TAM filing.

A. The TAM is an annual filing that the company makes to update its NPC in rates and to set the transition adjustments for direct access customers. Along with the forecast NPC, the 2027 TAM also includes test period forecasts for renewable energy production tax credits (PTCs).

Q. Please explain NPC.

A. NPC are the sum of fuel expenses, wholesale purchase power expenses, allowances, and wheeling expenses, less wholesale sales revenue.

Q. How does the TAM relate to NPC?

A. In the 2017 TAM Order, the Commission described the TAM and its purpose as follows:

> 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 TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the forecasts is of significant importance to setting fair, just and reasonable rates. Our

goal, therefore, is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.[1]

Q. Please explain how the company derives NPC.

A. The company derives NPC for a future test period based on a forecast using Aurora, which is a production cost model. Aurora simulates the operation of the company's power system on an hourly basis and provides an hourly forecast of NPC for the future test period.

Q. Which version of Aurora was used to prepare this initial filing?

A. The Aurora version used to prepare this initial filing was version 16.0.1006.[2]

Q. Are the results from the Aurora model reproducible?

A. Yes. The NPC forecasts provided by the company use input settings that allow for reproducible results. However, due to the introduction of battery energy storage systems into PacifiCorp's system, which bring considerable algorithmic complexity, certain models will take multiple days of runtime to produce the reproducible results. To help alleviate the time burden these runtimes would place on parties seeking to conduct independent modeling sensitivities, the company has provided versions of these models whereby input settings have been adjusted to allow for the reproduction of similar NPC forecasts in significantly less run time.

These versions will not produce reproducible results, but their results will be within a tight tolerance to the reproducible NPC forecast proposed by the company. Figure Reproducibility below shows approximate total-company NPC tolerances from adjusting these input settings. The company believes that providing intervenors

[1] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 2-3 (Dec. 20, 2016).
[2] Specifically, Aurora version 16.0.1006.9344 released January 21, 2026.

with more reasonable Aurora run times allows for increased auditing and analysis to be performed, a task that is made near infeasible if a single-model run takes multiple days.

It is important to note that the Company's NPC proposal in this docket is based on the *reproducible* model runs. The versions provided to parties for ease of auditing are not what customers' rates are calculated from.

Figure Reproducibility

Run	Lowered Runtime NPC	Reproducible NPC	Tolerance (%)
Washington Sale April 1st, 2027	$ 2,136,303,662	$ 2,121,724,334	-0.68%
Business As Usual	$ 2,270,602,844	$ 2,254,028,957	-0.73%
Washington Sale January 1st, 2027	$ 2,088,443,345	$ 2,071,118,726	-0.83%

As mentioned prior, the company used the lower reproducible NPC values in this filing, and the company intends to provide similar analysis in the Reply Update filing.

Q. Has the company proposed any modeling changes in the 2027 TAM?

A. Yes. The company proposes the following modeling changes in addition to all modeling changes proposed in the 2023, 2024, 2025, and 2026 TAM:

- Situs-assigned resources Black Cap Solar, Old Mill Solar, Pavant III, as well as Amor IX and Castle Solar (Utah Schedule 32 resources) are now included within the Aurora TAM NPC simulation to ensure an accurate system dispatch and consistency with actual operations. This also includes post simulation mark-to-market adjustments which is consistent with the Power Cost Adjustment Mechanism (PCAM) methodology.

Q. Did the company provide advance notice to the parties regarding the modeling changes proposed in this case?

A. Yes. In compliance with the TAM Guidelines, the company provided notice of changes to the company's modeling of NPC in the 2027 TAM. This notice was provided on February 27, 2026, and is included as Exhibit PAC/106.

Q. What non-precedential changes from prior TAMs have been carried forward into this TAM?

A. All proposed changes in the 2023, 2024, 2025 and 2026 TAM were accepted and are implemented in this filing. Please refer to Confidential Exhibit PAC/107,[3] Confidential Exhibit PAC/108,[4] Confidential Exhibit PAC/109[5] and Confidential Exhibit PAC/110[6] for support of those changes proposed in the preceding TAM filings and please refer to Exhibit PAC/105 for the NPC impact of those changes. To the extent that support is not found in the above referenced exhibits, then please refer to Exhibit PAC/112, Exhibit PAC/113, Exhibit PAC/114, and Exhibit PAC/115 for the necessary information.

Q. What inputs were updated for this filing?

A. The company updated all inputs to the 2027 TAM, including system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, the official forward price curve (OFPC) market prices for electricity and natural gas, fuel expenses, and the characteristics and availability of the company's

[3] Day-ahead/real-time (DA/RT) percentile modifier; DA/RT volume component correction; Average of averages market capacity limits.
[4] Average of averages market capacity limits; Market capacity limits applied to all markets.
[5] Hedging requirements; Unspecified purchased power; Incomplete source data.
[6] Day-ahead/real-time (DA/RT) price component; DA/RT volume component; DA/RT volume component correction.

generation facilities.

Q. What is the date of the OFPC the company used in this filing?

A. The company's filing uses the OFPC dated December 31, 2025.

Q. Will the company continue to update the OFPC through the pendency of this proceeding?

A. Yes. In accordance with the current TAM Guidelines, the company's reply update will incorporate the most recent OFPC that is available at the time the update is prepared. The November indicative update will incorporate an OFPC from within nine days of the filing, and the November final update will incorporate an OFPC from within seven days of the filing. This ensures that the most up-to-date market information is used in the forecast, providing a more accurate estimate of NPC for the test period.

Q. What is the total-company NPC in the TAM for CY 2027?

A. The total-company forecast NPC for CY 2027 is approximately $33.18 per megawatt-hour ($/MWh).[7] This is approximately $3.00/MWh lower than the preliminary total-company 2025 actual NPC of approximately $36.18/MWh.[8] Further details on the total-company NPC forecast for 2027 are provided in Confidential Exhibit PAC/102.

Q. What is the decrease to Oregon-allocated NPC and the impact to Oregon rates?

A. As shown in Exhibit PAC/101, there is a decrease to Oregon-allocated NPC—relative to the 2026 NPC forecast, not the preliminary 2025 actuals—of

[7] $2.122 billion. See Confidential Exhibit PAC/102.
[8] Preliminary total company NPC $2.324 billion.

approximately $3.00/MWh[9] and an increase in PTCs (decrease to rates) of approximately $5.2 million. After adjusting for the variance from loads, the 2027 TAM results in a decrease to Oregon rates of approximately $3.16/MWh.[10] As explained in the testimony of company witness Ridenour, the 2027 TAM results in an overall average rate decrease of 2.8 percent, or $55.7 million (Oregon-allocated).

IV. SALE OF WASHINGTON ASSETS

Q. Did the company model the sale of Washington assets in its 2027 TAM forecast?

A. Yes. The company included adjustments to the TAM forecast with the assumed sale start date of April 1, 2027. The sale of Washington assets decreases forecast net power costs from $33.52/MWh to $33.18/MWh.

V. WESTERN ENERGY IMBALANCE MARKET BENEFITS

Q. Please summarize the proposed changes to PacifiCorp's Western Energy Imbalance Market (WEIM) benefits forecasting models.

A. The company proposes to alter the forecasted WEIM transfers for the PacifiCorp East (PACE) Export and Import models to align with California solar export trends in future NPC filings. The company also recommends updating the months considered as California solar export months to span from February to June.

Q. Please explain how PacifiCorp forecasts WEIM benefits today.

A. The company builds logarithmic regression models from historical WEIM benefits, power prices, gas prices, historical WEIM energy transfers, and an assumption about California solar exports. There are models for PACE exports, PacifiCorp West (PACW) exports, PACE imports, and PACW imports. Each model takes the form

[9] $30.4 million decrease without and before accounting for change in customer usage.
[10] $38.1 million. The $/MWh based on load at system level, prior to line losses.

log(Y) ~ log(X), where Y is the outcome variable and X is the predictor variable. The models are built as follows:

- PACE Exports: log(WEIM Benefits) ~ log(Power Price) + log(Gas Price) + log(Transfers) + Solar_Increasing
- PACW Exports: log(WEIM Benefits) ~ log(Power Price) + log(Transfers)
- PACE Imports: log(WEIM Benefits) ~ log(Transfers) + Solar_Increasing
- PACW Imports: log(WEIM Benefits) ~ log(Power Price) + log(Transfers)

Below is a description of the variables above.

- WEIM Benefits: Historical WEIM transfer benefits
- Power Price: Monthly, weighted-average power prices. Prices from the Mona electricity hub are used for PACE models while prices from the Mid-Columbia electricity hub are used for PACW models.
- Gas Price: Monthly average gas prices. Prices from the Opal gas hub are used for PACE models while prices from the Stanfield gas hub are used for PACW models.
- Transfers: WEIM transfers for each balancing authority area and transfer direction.
- Solar_Increasing: Variable used to estimate the amount of solar capacity in California that may be available for transfer in the WEIM. The binary variable is used for the months of March, April, May, June, and July.

After the company builds the above models with historical data, the models are fed forecasts on power prices, gas prices, transfers, and solar capacity growth in California to predict future WEIM benefits.

Q. How does the company forecast WEIM transfers to be used in the model to forecast WEIM benefits?

A. The company uses two-year historical average transfers for each balancing area and benefit direction to set future WEIM transfer assumptions in the model. Two years' worth of data is reasonable as it includes data for when the WEIM had full membership, and it can capture recent market trends and market participant behavior. Using too many years of historical data may cause the assumptions about future WEIM transfers to underestimate benefits since there has been consistent growth in WEIM transfers as more entities have joined the WEIM.

In PacifiCorp's update to its WEIM benefits forecasting model for the 2026 TAM,[11] it was determined that transfers in PACE were seasonal, while transfers in PACW are not. Therefore, a two-year, seasonal average is used to forecast the PACE transfers. The seasonal definitions used are as follows:

- Winter: December – February
- Spring: March – May
- Summer: June – August
- Fall: September - November

Q. How does the company propose to alter its forecasting models with respect to the WEIM transfer forecasts?

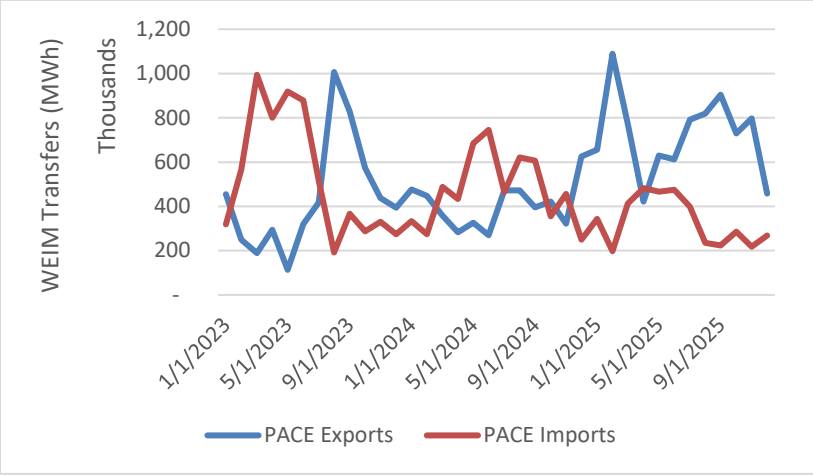
A. The company proposes to align the seasonal definitions for the PACE Export and Import forecasting models with the company's understanding of the California solar

[11] *In the Matter of PACIFICORP, dba PACIFIC POWER, 2026 Transition Adjustment Mechanism*, Docket No. UE 450 (Apr. 1, 2025).

export months. For the PACE Export and Import WEIM transfer forecasts, PacifiCorp proposes to average the WEIM transfers during the California solar export months for the past two years for months that were considered solar export months. For non-solar export months, the WEIM transfer forecast would be calculated as the average WEIM transfer during the non-solar export months from the past two years. Solar export months were originally considered to be March through July, which is the definition used for the "Solar_Increasing" variable in PacifiCorp's PACE Export and Import forecasting models.

By making this change, the company acknowledges that the WEIM transfers in and out of the PACE balancing authority area (BAA) are more related to whether there is excess solar in California than related to a typical seasonal definition. This trend can be seen by looking at the company's historical transfers in and out of the PACE BAA. The figure below shows historical WEIM PACE exports and imports between January 2023 and December 2025.

Figure 1: Historical PACE WEIM Transfers



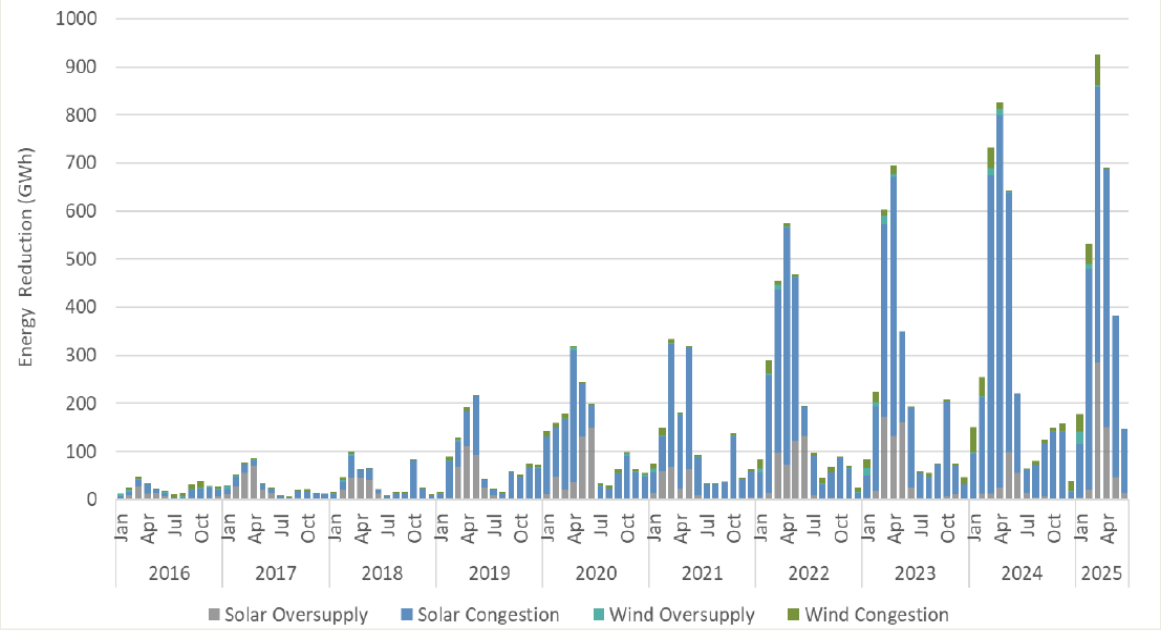
The figure above shows there is a pattern that aligns with the months where California is likely exporting solar energy throughout the WEIM. PACE imports

have historically increased starting around early spring and decreased around in the middle of the summer, while PACE exports were highest in the late summer months.

Q. Does the company propose making any other changes to its forecasting models?

A. Yes. As PacifiCorp was evaluating the change to forecasting WEIM transfers, the company saw data that suggested PacifiCorp's current designation of California solar export months should be revised. Data from the California Independent System Operator (CAISO) on solar production reductions led PacifiCorp to believe that there is not much surplus solar in California during the month of July relative to other months, but there has been a significant amount of surplus solar in February in recent years. The figure below is from the CAISO's Market Performance and Planning Forum for quarter two 2025[12] and shows the energy reduction of solar and wind resources.

Figure 2: Energy Reduction of Solar and Wind Resources within the CAISO BAA



[12] CAISO, *Market Performance and Planning Forum* 56 (June 26, 2025) available at https://www.caiso.com/documents/presentation-market-performance-and-planning-forum-jun-26-2025.pdf.

The figure shows that there are typically high reductions of solar energy between the months of February and June, but not in July. As such, the company proposes removing July and adding February as an excess solar month for the "Solar_Increasing" variable and forecasting WEIM transfers for the PACE BAA.

Q. Do the forecasting models show better model fit after the company's proposed changes to the months that are considered as California solar surplus months?

A. Yes. The company tested the PACE Export and Import models using the adjusted R-squared metric with and without the proposed changes.

Table 1: Adjusted R-Squared Values for Selected Forecasting Models

	Original	Updated
PACE Exports	0.734	0.737
PACE Imports	0.584	0.590

The table shows that the company's proposal for changing the California solar surplus months slightly improves the model fit for the PACE forecasting models when compared to the original models. While the improvement to model fit is small, PacifiCorp believes the adjusted R-squared values show that the company's recommendation is reasonable.

Q. Do the proposed changes affect the 2027 WEIM benefits forecast?

A. The 2027 WEIM benefits forecast does change slightly after making the proposed changes. The company ran the forecasting models using data through December 2025 using the original models and the updated models. The company's 2027 WEIM benefits forecast using the original model leads to a yearly benefit of roughly

$93.3 million. Using the updated models for PACE, the 2027 WEIM benefits forecast is roughly $93.6 million. A small change in forecasted benefits is expected as the change to the forecasting models was relatively minor.

VI. DIRECT ACCESS

Q. Does the company have any proposals relating to direct access?

A. Yes. As proposed—and uncontested by parties—in the UM 2024 Direct Access investigation—which has been fully briefed and is pending Commission order on March 31, 2026, the company proposes to switch to the spreadsheet-based method for calculation of the incremental Transition Adjustments. Confidential Exhibit PAC/116 provides sample Schedule 30 and 48 Transition Adjustments, comparable to the sample calculations provided in the fifteen-day workpapers. Switching to the spreadsheet-based method replaces most of the 62 NPC model runs and 74 NPC reports with a straightforward spreadsheet that calculates the Transition Adjustments using transparent, observable market prices while continuing to calculate the base NPC in the Aurora model. This change makes the Transition Adjustments transparent, simpler to audit, and simpler to replicate. The average change to the sample 2027 Schedule 30 and 48 Transition Adjustments that results from switching to the spreadsheet-based method is an [redacted] to the Transition Adjustment credits paid to direct access customers as shown in Confidential Figure Transition Adjustment Credits.

Confidential Figure Transition Adjustment Credits 30 Secondary ¢/kWh

Confidential Figure Transition Adjustment Credits 48 Primary ¢/kWh

VII. NPC VALIDATION

Q. Is $33.18/MWh a reasonably accurate forecast for total-company NPC?

A. Yes. Preliminary 2025 Actual NPC is $36.18/MWh. Forecast 2027, as compared to preliminary actual 2025:

(1) 2027 Pacific Northwest summer and winter peak power prices **increase** by 41 percent and Four Corners region summer and winter peak power prices **increase** by 43 percent.

(2) 2027 Pacific Northwest summer and winter natural gas prices **increase** by 152 percent and Rocky Mountain region summer and winter natural gas prices **increase** by 31 percent.

These underlying market fundamentals indicate that all else equal, the 2027 total-company NPC would be higher than preliminary 2025 actual total-company NPC. However, the upward cost pressure associated with higher commodity prices is offset by four developments that are not reflected in the preliminary 2025 actuals: (1) battery energy storage systems which allow for intra-day price arbitrage opportunities, and provide dispatchable capacity; (2) expected benefits from the Extended Day Ahead Market (EDAM); (3) a full year of wind generation from Rock Creek I and II (590 MW of capacity); (4) the sale of Washington assets. Collectively, these changes mitigate the impact of higher market prices on the 2027 NPC forecast relative to preliminary 2025 actual NPC.

Q. Why are summer and winter prices particularly critical when comparing prices?

A. Summer and winter peak periods are periods of high customer demand and stressed system conditions. Higher power prices in those periods will produce NPC that is substantially higher relative to any decrease in NPC that may result from lower prices in spring and fall months, which have light load and relatively mild system conditions.

VIII. DISCUSSION OF NPC CHANGES IN THE TAM

Q. Please generally describe the changes in this 2027 forecast NPC compared to preliminary 2025 actual NPC.

A. On a $/MWh basis, 2027 forecast NPC of $33.18/MWh is approximately $3.00/MWh lower than preliminary actual NPC of $36.18/MWh. As mentioned above, this decrease is driven by the implementation of battery energy storage systems, EDAM benefits, a full year of wind generation from Rock Creek I and II as well as the modeled sale of Washington assets beginning April 1, 2027.

Tables 'NPC Prices,' 'NPC Energy,' and 'NPC Dollars' illustrate the changes in total-company NPC by category from the preliminary 2025 actual NPC to the 2027 forecast NPC. 'NPC Energy' and 'NPC Dollars' are not the most comparable due to the modeled sale of Washington assets, which significantly decreases things like forecasted load, gas generation, and fuel expense.

NPC Prices

Net Power Cost Reconciliation			
	2025 $/MWh	**2027 $/MWh**	**Change**
NPC Components			
Wholesale Sales Revenue	44.77	49.72	4.95
Purchased Power Expense	57.49	43.32	(14.17)
Coal Fuel Expense	30.35	30.41	0.06
Natural Gas Fuel Expense	34.38	36.57	2.19
Other Expense	20.88	21.73	0.85
Total NPC	**36.18**	**33.18**	(3.01)

NPC Energy

Net Power Cost Reconciliation		
	MWh	**$/MWh**
2025 Actual Load	**64,217,934**	**36.18**
Change to Load:		
Wholesale Sales Increase	332,949	
Purchased Power Increase	3,347,525	
Coal Generation Decrease	(3,876,638)	
Natural Gas Generation Decrease	(1,011,630)	
Other Generation Increase	938,846	
Total Change to Net System Load	**(268,948)**	
2027 Forecast Load	**63,948,987**	**33.18**

NPC Dollars

Net Power Cost Reconciliation		
	($ millions)	**$/MWh**
2025 Actual NPC	**2,324**	**36.18**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	(3.4)	
Purchased Power Expense	(120.6)	
Coal Fuel Expense	(116.4)	
Natural Gas Fuel Expense	(3.3)	
Wheeling and Other Expense	41.7	
Total Change to NPC	**(202.0)**	
2027 Forecast NPC	**2,122**	**33.18**

Q. Please explain the decrease in purchased power expense and the decrease in wholesale sales revenue.

A. The decrease in purchased power expense is driven by forecasted EDAM benefits. Higher load obligations (with consideration of the sale of Washington assets) reduce

surplus energy available for market sales, thereby lowering wholesale sales volumes. The decline in volumes results in a corresponding decrease in wholesale sales revenue.

Q. Please explain the decrease in coal fuel expense and the decrease in natural gas fuel expense.

A. The decrease in coal fuel expense is primarily due to lower coal-fired generation, driven by the conversion of Naughton Units 1 and 2 from coal to natural gas and the previously scheduled retirement of Craig Unit 1 at the end of 2025. Correspondingly, natural gas fuel expense increased as Naughton Units 1 and 2 transitioned to gas-fired operations, shifting fuel consumption from coal to natural gas. The removal of Chehalis starting April 1, 2027 results in a decrease in natural gas fuel burn expense when compared to 2025 actuals.

Q. Please explain the increase in wheeling and other expense.

A. The increase in wheeling and other expense is primarily driven by the implementation of the EDAM Grid Management Charge (GMC), which represents a new cost obligation associated with participation in EDAM. This cost obligation is more than offset by the forecasted EDAM benefits of over $95 million on a total-company basis.[13] In addition, wheeling expenses reflected in the TAM forecast are based on historical transmission usage necessary to support purchased power deliveries. As purchased power volumes have increased over time, the associated wheeling requirements have similarly increased. This combination of new market-related

[13] Specifically, $97,338,455 for the 2027 forecast period.

charges and higher transmission utilization contributes to the observed growth in wheeling and other expense.

IX. MODELING IMPROVEMENTS

Q. In addition to the modeling improvements proposed in the 2023 TAM, the 2024 TAM, the 2025 TAM and the 2026 TAM, has the company incorporated any additional modeling improvements into this year's TAM?

A. Yes. The company is proposing the following modeling improvement:

- Situs-assigned resources Black Cap Solar, Old Mill Solar, Pavant III, as well as Amor IX and Castle Solar (Utah Schedule 32 resources) are now included within the Aurora TAM NPC simulation to ensure an accurate system dispatch and consistency with actual operations. This will also include post simulation mark-to-market adjustments, which are consistent with the PCAM methodology.

A. Complete Resource Inclusion

Q. In Confidential Exhibit PAC/115, you present prior testimony from the 2026 TAM supporting the inclusion of the Rolling Hills Wind Facility in the TAM forecast with an appropriate adjustment. Similarly, what other resources is the company proposing to include in the model to ensure consistency with actual net power costs?

A. The company is now incorporating the situs-assigned resources Black Cap Solar, Old Mill Solar, and Pavant III as well as Amor IX and Castle Solar (Utah Schedule 32 resources) into the NPC forecasting model to more accurately reflect actual system operations. These additions ensure alignment between modeled NPC and the

resources that the company dispatches and accounts for in real-time operations. Consistent with established PCAM treatment, the company continues to apply the same adjustments to these resources in the forecast to ensure customers remain held harmless as these situs-assigned resources are incorporated into NPC modeling.

Q. What is the NPC impact of this modeling change?

A. When taking into account the post simulation adjustments, the impact of this modeling change is a decrease to Oregon-allocated NPC of $1.3 million.

B. Non-Precedential Modeling Improvements

Q. How has the company treated the non-precedential modeling improvements from the 2023, 2024, 2025, and 2026 TAM?

A. All non-precedential modeling improvements from the 2023, 2024, 2025, and 2026 TAM are included in this filing. Please refer to Confidential Exhibit PAC/107,[14] Confidential Exhibit PAC/108,[15] Confidential Exhibit PAC/109,[16] and Confidential Exhibit PAC/110[17] for supporting testimony. To the extent that support is not found in the above referenced exhibits, then please refer to Exhibit PAC/112, Exhibit PAC/113, Exhibit PAC/114, or Exhibit PAC/115 for the necessary information.

[14] Day-ahead/real-time (DA/RT) percentile modifier; DA/RT volume component correction; Average of averages market capacity limits.
[15] Average of averages market capacity limits; Market capacity limits applied to all markets.
[16] Hedging requirements; Unspecified purchased power; Incomplete source data.
[17] Day-ahead/real-time (DA/RT) price component; DA/RT volume component; DA/RT volume component correction.

Q. In Confidential Exhibit PAC/107, you present prior testimony from the 2024 TAM supporting the use of the Day-Ahead/Real-Time (DA/RT) percentile modifier and the average of averages market caps methodology. Are there any updates to that testimony?

A. Yes. First, Confidential Figure 6 in Confidential Exhibit PAC/107 is updated below, with more recent data, as Confidential Figure 'Flat vs Percentile' illustrates the real, actual, historical DA/RT price component contrasted with a hypothetical flat adder, showing that the data supports the percentile adder as more accurate. Second, Confidential Figure 11 in Confidential Exhibit PAC/107 is updated below, with more recent data, as Confidential Figure 'Market Sales Down' and illustrates the 2027 forecast sales as compared to historical actual sales, showing that the data does not support a third quartile of averages approach. Please refer to Confidential Exhibit PAC/107,[18] Confidential Exhibit PAC/108,[19] and Confidential Exhibit PAC/109[20] for further evidentiary detail on these issues.

[18] Day-ahead/real-time (DA/RT) percentile modifier; DA/RT volume component correction; Average of averages market capacity limits.
[19] Average of averages market capacity limits; Market capacity limits applied to all markets.
[20] Day-ahead/real-time (DA/RT) price component; DA/RT volume component; DA/RT volume component correction.

1 **Confidential Figure Flat vs Percentile**

2 **Confidential Figure Market Sales Down**

Q. In Confidential Exhibit PAC/115, you present prior testimony from the 2026 TAM supporting model input optimization changes. Please provide the updated impact of optimizing the use of model inputs and features.

A. The Oregon-allocated NPC impact model input optimization changes is an increase of $0.4 million.[21]

Q. In Confidential Exhibit PAC/115, you present prior testimony from the 2026 TAM supporting an EDAM Benefits methodology. Please provide the forecasted EDAM benefits for 2027.

A. The Oregon-allocated EDAM benefits are a decrease of $28.1 million.[22] This decrease is driven by more entities expected to participate in EDAM in 2027.

X. TAM ACCURACY

Q. Please describe the importance of the modeling improvements proposed by the company.

A. Since the 2023 TAM, the company has proposed and implemented several modeling enhancements that materially improve the accuracy of NPC and PTC forecasts. As shown in Figure OR TAM, NPC forecast error has greatly improved, with preliminary 2025 data showing the most accurate NPC forecast since the 2017 TAM. Figure OR PTC shows how the modeling enhancements have also improved the accuracy of the PTC benefits forecast in the TAM, with the 2025 TAM again showing the most accurate PTC forecast since the 2020 TAM. Finally, the company is continuing to improve the accuracy of the TAM forecast, with another modeling

[21] Decrease to total-company NPC of $1.3 million.
[22] Decrease to total-company NPC of $97.3 million.

improvement proposed in my testimony above, which decreases Oregon-allocated NPC by $1.3 million.[23]

Figure OR TAM

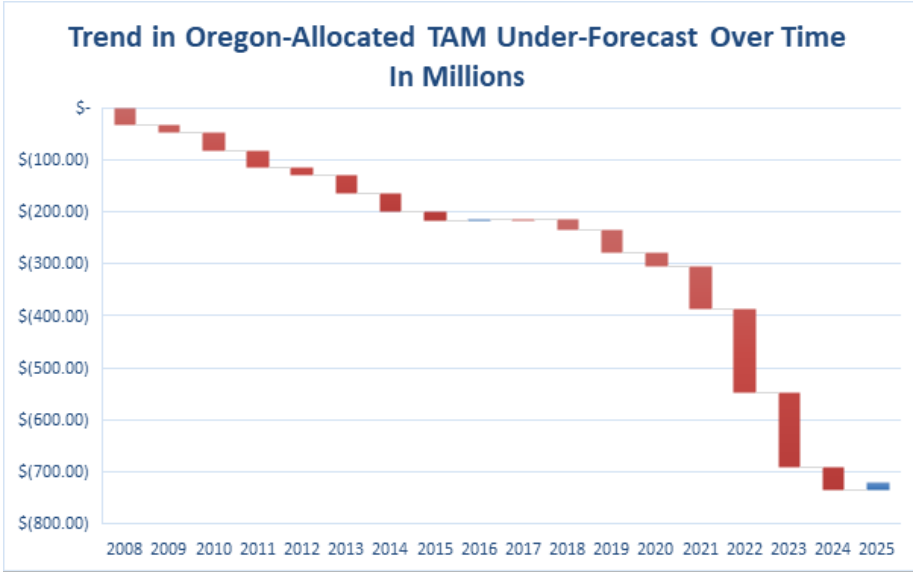
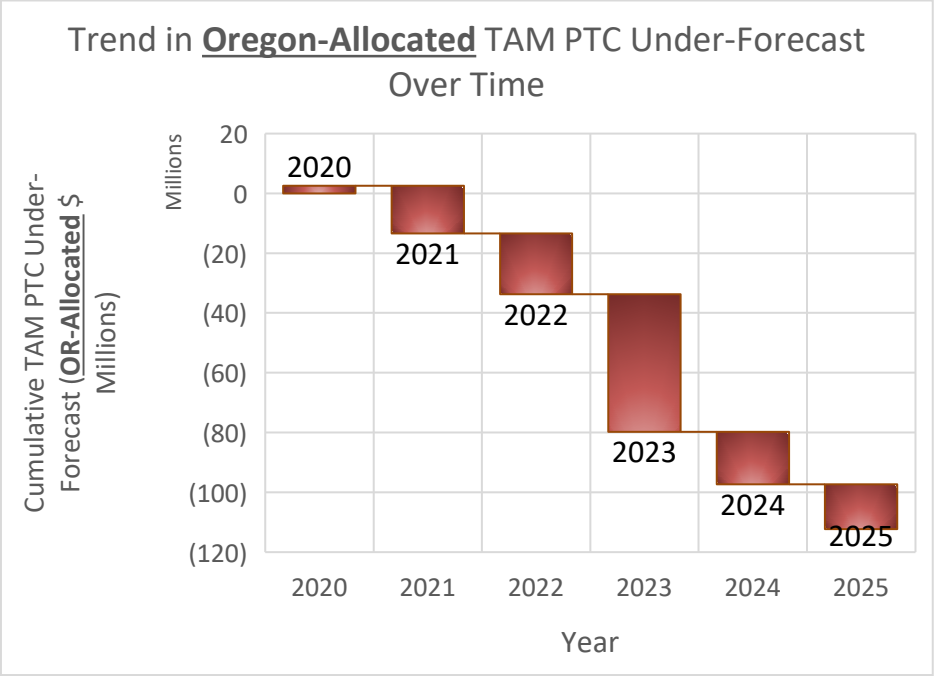


Figure OR PTC



[23] See section on Complete Resource Inclusion

XI. PRODUCTION TAX CREDITS

Q. Please describe the treatment of renewable energy PTCs in the 2027 TAM.

A. The 2027 TAM includes changes in projected levels of PTCs. Exhibit PAC/103 shows the forecast level of PTCs for 2027 compared to the level of PTCs established in the 2026 TAM. The forecast value of Oregon-allocated PTCs for the 2027 test period is approximately $107.5 million, which is higher than the $102.3 million included in the 2026 TAM, resulting in a decrease to the 2027 TAM of $5.2 million.

Q. How are PTCs calculated for the 2027 TAM?

A. The PTC provides a federal income tax credit for the first 10 years of a renewable energy facility's operation. The PTC is calculated by multiplying the qualifying generation by the applicable PTC rate and then grossing-up for taxes.

Q. Please describe the capacity, capacity factors, generation, and PTCs for the wind projects in the 2027 TAM.

A. As seen in Confidential Table 'Company-Owned Wind Projects Generation and PTC Data' below, on a total-company basis, the company-owned wind capacity is approximately 2,937 MW and total forecast generation is 8,682,063 MWh. The total tax-adjusted PTCs on an Oregon-allocated basis are $107.5 million.

Confidential Table: Company-Owned Wind Projects Generation and PTC Data

	Total Company				Oregon Allocated		
Plant Name	PTC Value	LGIA Capacity (MW)	LGIA Capacity Factor	Generation (MWH)	Factors CY 2027	CY 2027 Initial Filing	Revenue Requirement *(See Note 1)*
Glenrock	[redacted]	99.0	[redacted]	[redacted]	29.334%	[redacted]	
Glenrock III		39.0			29.334%		
Goodnoe		94.0			29.334%		
High Plains		99.0			29.334%		
Leaning Juniper		100.5			29.334%		
Marengo I		156.0			29.334%		
Marengo II		78.0			29.334%		
McFadden Ridge		28.5			29.334%		
Rolling Hills		99.0			29.334%		
Seven Mile		99.0			29.334%		
Seven Mile II		19.5			29.334%		
Dunlap		111.0			29.334%		
Foote Creek I		41.4			29.334%		
TB Flats		500.0			29.334%		
Cedar Springs II		200.0			29.334%		
Ekola Flats		250.0			29.334%		
Pryor Mountain		239.8			29.334%		
Foote Creek III - IV Wind		43.4			29.334%		
Rock Creek 1		190.0			29.334%		
Rock Creek 2		400.0			29.334%		
Rock River 1		50.0			29.334%		
Total Production Tax Credit	$ 276,239,595	2,937.1		8,682,063		$ 81,033,112	$107,451,875

Note 1 - Revenue Requirement represents the PTC amount grossed up for the tax rate.

XII. 2026 TAM SETTLEMENT AND 2026 RENEWABLE ADJUSTMENT CLAUSE ORDER

Q. Please describe what the company agreed to in the 2026 TAM settlement and was also requested to do in the 2026 Renewable Adjustment Clause (RAC) order.

A. In the 2026 TAM settlement, the company agreed to provide analysis showing the NPC benefits of Gateway South independent of the generation assets.[24] Additionally, the company agreed to conduct a jurisdictional deliverability analysis for Rock Creek

[24] *In the Matter of PACIFICORP, d/b/a PACIFIC POWER, 2026 Transition Adjustment Mechanism*, Docket No. 450, Order No. 25-421, Appendix A 6 (Oct. 27, 2025).

I and II and disaggregate NPC reporting in future power cost filings.[25]

C. Benefits of Gateway South, Rock Creek I, and Rock Creek II

Q. Please describe the settlement as it relates to Gateway South, Rock Creek I, and Rock Creek II.

A. In the 2026 Oregon TAM settlement, the company agreed to produce and provide a study or analysis showing the NPC benefits of Gateway South independent of the generation assets.[26] To comply the company performed three separate Aurora runs, using the 2027 forecast provided in the TAM. Each run was done in isolation, meaning for the Gateway South run, the company only removed Gateway South, for the Rock Creek I run the company made no change other than to remove Rock Creek I, and for the Rock Creek II run, the company made no change other than to remove Rock Creek II.

Q. Please describe the impact to NPC and PTCs of removing Gateway South.

A. On a total-company basis, removing Gateway South resulted in forecast 2027 net power costs increase by $91.2 million and total-company production tax credits decreased by $26.3 million for a combined impact of $117.5 million. The increase in net power costs was driven by more constrained wind generation, resulting in decreased market sales and increased market purchases and thermal generation and fuel costs.

[25] *See In the matter of PacifiCorp dba Pacific Power's 2026 Transition Renewable Adjustment Clause*, Docket No. UE 451, Order No. 25-505 (Dec. 15, 2025).
[26] *Id.*

Q. Please describe the impact to NPC and PTCs of removing Rock Creek I.

A. On a total-company basis, removing Rock Creek I resulted in a forecast 2027 NPC increase by $18.6 million and total-company PTCs decreased by $23.2 million for a combined impact of $41.8 million.

Q. Please describe the impact to NPC and PTCs of removing Rock Creek II.

A. On a total-company basis, removing Rock Creek II resulted in a forecast 2027 NPC increase by $42 million or and total-company PTCs decreased by $45.8 million for a combined impact of $87.9 million.

Q. Please explain your concerns with this analysis.

A. As detailed at length in the 2026 TAM, the NPC and PTC reporting is not aligned with how Gateway South was evaluated and selected through the company's integrated resource planning (IRP) process. The IRP modeling that supported Gateway South assumed the coordinated development of the transmission line and associated wind resources (including projects such as Rock Creek I and II). In other words, the transmission investment and the wind additions were planned as a combined portfolio: without Gateway South, these wind resources would not be able to interconnect and deliver energy to load, and without the wind resources, the principal system value of Gateway South would not be realized to the same extent.

As a result, attempting to report or evaluate benefits on a "standalone" basis—by disaggregating Gateway South from the portfolio it enables—creates an artificial distinction that does not reflect the integrated nature of system planning. Separating NPC and PTC benefits in this manner risks understating (or overstating) value by attributing portfolio benefits to individual components in a way the IRP did not

contemplate. A prudency assessment should be grounded in the ex ante information, assumptions, and analysis available when the decision was made, not in a retroactive decomposition of portfolio outcomes.

In addition, annual power cost filings inherently rely on updated assumptions and market conditions that differ from the inputs used in the IRP scenarios. As those assumptions change over time—such as fuel prices, market prices, hydrology, load, and renewable performance—the calculated "benefits" associated with Gateway South and the related wind resources will also change. Furthermore, annual NPC and PTC reporting can produce results that are retrospective and highly sensitive to year-specific conditions. This distinction between IRP modeling, which relies on inputs from a fixed point in time, and power cost forecasting, which incorporates annually updated inputs, is important when evaluating the NPC and PTC benefits of these multi-decade projects.

Q. The Commission expressed heightened interest in the results of this analysis simply due to "PacifiCorp's strong pushback to this information request."[27] Why does PacifiCorp maintain its position on the value of this information?

A. PacifiCorp maintains its concerns with this requested information on NPC reporting that attempt to isolate Gateway South's benefits from the wind resources it enables because presenting these standalone NPC and PTC results for Gateway South risks distorting the Commission's understanding of the project's benefits and could support a decision based on an incomplete view of the record, *regardless of the directionality of the results.*

[27] Docket No. UE 451, Order No. 25-505, page 9 (Dec. 15, 2025).

XIII. ACTUAL OPERATIONS CHANGES

D. Resource Adequacy

Q. What is resource adequacy and how does it benefit customers?

A. Resource adequacy is the planning, typically for the next year or season, by a utility or load serving entity to serve load in a reliable manner. This planning typically includes ensuring an adequate amount of generation to serve peak load plus a planning reserve to account for some uncertainty, such as outages, underperformance of resources, and higher-than-forecast loads. Customers benefit from the utility being resource adequate through increased reliability, less market exposure, and more stable power costs.

Q. Please describe the changes that the company is proposing to its current risk management policy and hedging program and practices.

A. As an initial matter, the company routinely evaluates its risk management policy to ensure risks are being adequately addressed. The risk management policy is being updated to specifically address two risks. First, is the resource adequacy risk or **supply risk**. The second is the **price risk** or price volatility.

First, the company must ensure that it meets resource adequacy standards to ensure reliability. Hourly load for the peak day of the month, coupled with a planning reserve margin, are offset by an hourly forecast of wind and solar output on the peak load day to determine the peak net load hour. Once the peak net load for each month is identified and quantified, those peak net loads are offset by the capacity contribution values of non-wind and non-solar resources in order to determine the overall capacity position by month. [redacted]

[redacted] Additionally, price risk hedges are not included in the TAM forecast as [redacted]

Q. Are these positions calculated for the PacifiCorp system as a whole?

A. No. The company uses two books, one calculated for a Washington portfolio and the other calculated for a five-state portfolio. With the sale of Washington included in the TAM forecast, there is only one book (for the five-state portfolio) after April 1st in the TAM forecast.

Q. What is the NPC impact of this change to actual operations?

A. The NPC impact of meeting resource adequacy requirements results in a decrease to Oregon-allocated NPC of $22 million.[28]

Q. Does PacifiCorp consider this a methodology or modeling change?

A. No, this is not a modeling or methodology change, it reflects actual operations in the forecast.

[28] Decrease to total-company NPC of $76.3 million.

XIV. COMPLIANCE WITH TAM AND RAC ORDERS

Q. The 2026 RAC Order describes certain actions that need to be taken in the 2027 TAM filing. What are those actions?

A. In Order No. 25-505, the Commission ordered PacifiCorp to conduct a jurisdictional deliverability analysis for Rock Creek I and II and disaggregate NPC reporting in future power cost filings.[29] The company has complied by providing the jurisdictional deliverability analysis[30] as well as the forecasted NPC and PTC impacts associated with Rock Creek I, Rock Creek II and Gateway South in the 2027 TAM forecast.

Q. The 2021 TAM Order describes certain actions that need to be taken prior to the 2027 TAM filing. What are those actions?

A. In Order No. 20-392, the Commission adopted a stipulation reached between the parties.[31] PacifiCorp agreed to the following:

- Performing an informational model run that removes any operational constraints related to the minimum take provisions in the coal supply agreements and uses an average coal price for purposes of dispatching coal plants (to be provided in 15-day workpapers).

Q. Has the company performed this informational model run?

A. Yes. The informational model run will be provided with the 15-day workpapers for this filing.

[29] *See In the matter of PacifiCorp dba Pacific Power's 2026 Transition Renewable Adjustment Clause*, Docket No. UE 451, Order No. 25-505 (Dec. 15, 2025).
[30] *In matter of PacifiCorp dba Pacific Power 2027 Transition Adjustment Mechanism*, Docket No. UE 469, PacifiCorp's Jurisdictional Deliverability Analysis (Mar. 12, 2026).
[31] *See In the matter of PacifiCorp dba Pacific Power's 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 (Oct. 30, 2020).

Q. Were there other items that needed to be followed up on from prior TAM Orders?

A. Yes. The following Table 'Information Requested in Prior Orders' lists the information that was ordered or agreed to in prior TAM Orders and describes where it has been provided:

Table: Information Requested in Prior Orders

Order/Stipulation Requirement	**Details**
The Commission has disallowed Washington Climate Commitment Act (CCA) costs as a state-specific initiative that is properly allocated to Washington under PacifiCorp's Multi-State Process.	There are no CCA costs to include
PacifiCorp affirms that the Schedule 296 calculations used to calculate the Consumer Opt-Out Charge, including all supporting work papers, will be provided consistent with the TAM guidelines, 30 days after filing the TAM.	Will be provided in the 30-day workpapers for this filing.
As long as there are coal-fired Jim Bridger units in Oregon rates and they are fueled with coal from Bridger Coal Company, PacifiCorp will provide a copy of the updated annual Bridger Coal Company mine plan along with any alternatives that were also evaluated for PacifiCorp in future TAM filings.	These are provided in PacifiCorp's workpapers associated with this filing.
PacifiCorp agrees to reduce modeled minimum take for the Hunter and Huntington Plants by a combined 12,400,000 MMBtus…in each TAM	Hunter and Huntington modeled minimum takes are reduced in NPC forecast.

XV. COMPLIANCE WITH TAM GUIDELINES

Q. Did the company prepare this filing in accordance with the TAM Guidelines adopted by Order No. 09-274, as clarified and amended in later orders?

A. Yes. The company has complied with the TAM Guidelines applicable to the initial filing in a TAM.

Q. Does this filing include updates to all NPC components identified in Attachment A to the TAM Guidelines?

A. Yes.

Q. What workpapers did the company provide with this filing?

A. In compliance with Attachment B to the TAM Guidelines, the company provided access to the Aurora model and workpapers concurrently with this initial filing. Specifically, the company provided the NPC report workbook and the Aurora project.

Q. Did the company provide a step log of model and input changes describing changes to the company's modeling or inputs that are not considered a standard annual update?

A. Yes. The company has provided step logs as Exhibit PAC/104 and Exhibit PAC/105.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 470
Exhibit PAC/207
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Rick T. Link

Brattle EDAM Benefits Study

May 2026

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

REDACTED
Docket No. UE 470
Exhibit PAC/300
Witness: M. Ryan Weems

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of M. Ryan Weems

May 2026

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ATTACHED EXHIBITS

Confidential Exhibit PAC/301—S&P Global Ratings, "Research Update: PacifiCorp Ratings Removed from CreditWatch Negative, Outlook Negative"

Confidential Exhibit PAC/302—"Research Update: PacifiCorp Outlook Revised to Positive Following Oregon Court of Appeals Decisions"

Exhibit PAC/303—Pro Forma Cost of Long-Term Debt

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power.

A. My name is M. Ryan Weems, and my business address is 825 NE Multnomah Street, Suite 1900, Portland, Oregon 97232. I am currently PacifiCorp's Senior Vice President, Chief Financial Officer and Treasurer.

Q. Please describe your education and professional experience.

A. I received a Bachelor of Business Administration with an emphasis in Accounting from Warner Pacific College in 2000. I joined PacifiCorp in 2001 and have taken on roles of increasing responsibility before being appointed to my current position in 2025.

II. SUMMARY AND PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony supports PacifiCorp's overall cost of capital recommendation, including capital structure and cost of debt. This includes a discussion of PacifiCorp's financing needs, credit ratings, credit metrics, financial stabilization efforts, and explanation of the material changes in the company's credit ratings and financial metrics that have occurred since the last Oregon rate proceeding. My testimony also describes why this general rate case includes an interim rate proposal and how PacifiCorp meets the standard that the Public Utility Commission of Oregon (Commission) applies when considers interim rate proposals.

Overall, my testimony demonstrates why it is imperative for PacifiCorp and its Oregon customers that the Commission approve PacifiCorp's costs of capital and interim rates to avoid further credit downgrades.

Q. Please summarize your testimony.

A. Over the past three years, PacifiCorp's credit has been downgraded multiple times, and is currently one step above junk status. A single additional downgrade would materially impact PacifiCorp's ability to access credit at reasonable terms for our Oregon customers.

PacifiCorp is actively engaged in multiple financial stabilization efforts to avoid this result. These include, among others: (1) material support from PacifiCorp's parent, Berkshire Hathaway Energy (BHE), including the suspension of PacifiCorp's up-stream dividend to BHE for the next several years, BHE's agreement to purchase PacifiCorp's share of the Boardman-to-Hemingway transmission line in a long-term sale-leaseback transaction, and a springing guarantee for office construction in the Utah territory; (2) PacifiCorp's proposed sale of service territories—the entirety of its Washington service territory, and small portions of its Oregon service territory; (3) a reduction of PacifiCorp's near term capital expenditures; (4) a hypothetical capital structure based on a common equity ratio of 50.00 percent; and (5) a request for interim rates, resulting in an approximate 2.8 percent increase of approximately $55.1 million, effective June 4, 2026. As described further by PacifiCorp witnesses Ryan L. Flynn and Rick T. Link, the interim rate request will be completely offset by a decrease in rates from the 2022 Power Cost Adjustment Mechanism that was effective May 1, 2026.

These efforts remain vital to PacifiCorp's financial health, despite the recent Oregon Court of Appeals opinion in the *James* case, because substantial litigation on heavily contested issues with uncertain outcomes remains. Even if the *James* decision

materially limits PacifiCorp's wildfire-related liabilities, it will take several years and several credit ratings upgrades to return PacifiCorp to a healthy financial state.

To complement these financial stabilization efforts, PacifiCorp recommends the Commission approve an overall cost of capital of 7.56 percent. This includes a long-term debt cost of 5.41 percent, a return on equity of 9.70 percent as supported by the direct testimony of company witness Ann E. Bulkley, and a hypothetical capital structure comprised of 50.00 percent long-term debt and 50.00 percent common equity. The overall cost of capital and capital structure proposed in this rate case are set forth in Table 1.

Table 1: Hypothetical Overall Cost of Capital

Component	% of Total	Cost %	Weighted Average Cost %
Long-Term Debt	50.00%	5.41%	2.71%
Common Stock Equity	50.00%	9.70%	4.85%
	100.00%		7.56%

III. FINANCING OVERVIEW

Q. How does PacifiCorp finance its electric utility operations?

A. Generally, PacifiCorp finances its regulated utility operations using a mix of debt and common equity capital. The company can maintain its common equity capital by retaining its earnings or by receiving an equity contribution from its investor. The debt portion of the capital structure is supplied by the issuance of long-term debt such as first mortgage bonds or junior subordinated notes. The issuance of long-term debt requires a credit rating, and maintaining the company's credit rating is critical to

provide constant and affordable access to the debt capital markets. All of these factors assist in financing large capital expenditures.

Q. How does PacifiCorp determine the levels of common equity and debt to include in its capital structure?

A. As a regulated public utility, PacifiCorp has a duty and an obligation to provide safe, adequate, and reliable service to customers in its Oregon service area, while prudently balancing cost and risk. Major capital expenditures are required for new investments to fulfill its service obligation, including capital expenditures for maintaining and hardening its electric system, primarily transmission and distribution infrastructure, wildfire mitigation, and essential safety and reliability investments. These capital investments also have associated operating and maintenance costs.

In addition to capital investments, PacifiCorp procures a significant amount of fuel and energy to meet its customers electricity needs. In times of extreme weather disruptions in the wholesale market, this cost can be significant and, in some cases, is in advance of recovery. The company must have access to the debt capital markets as well as access to lines of credit and short-term debt to ensure that it has liquidity to manage its estimated cash outflows. As part of its annual business plan process, PacifiCorp reviews all of its estimated cash inflows and outflows to determine the amount, timing, and type of new financing required to support these activities and provide for financial results and credit ratings that balance the cost of capital with continued access to the financial markets.

Q. Please explain PacifiCorp's need for new capital.

A. PacifiCorp has a constant need for additional capital to maintain its existing transmission, distribution and generation assets, to connect new customers to the network, to mitigate wildfires by making significant investments in new technology and hardening its infrastructure, and for increased reliability, improved power delivery, and safe operations. PacifiCorp also needs new capital to fund long-term debt maturities.

Q. Do you have an estimate of PacifiCorp's forecasted capital expenditures over the next three years?

A. Yes. PacifiCorp expects to spend approximately $7.9 billion in capital expenditures from 2026 through 2028, with significant investments in wildfire mitigation efforts amounting to approximately $1.5 billion. Forecasted expenditures are included in Table 2 below.

Table 2: Forecast Capital Expenditures

Capital Expenditures ($ millions)	2026	2027	2028
Total Capital Expenditures	$2,884	$2,533	$2,455

IV. PACIFICORP'S FINANCIAL HEALTH

Q. What is the purpose of this section?

A. I discuss PacifiCorp's credit ratings and certain credit metrics, and why they are especially important given PacifiCorp's current financial condition.

A. Credit Ratings Downgrades

Q. What are credit ratings, and why are they important?

A. Credit ratings are an estimate of a utility's ability to meet long-term financial obligations, and reflects the probability of default by the issuer on each rated security.

PacifiCorp is currently rated by two of the three credit rating agencies: Standard and Poor's (S&P) and Moody's Investors Service (Moody's). These ratings function as a forward looking measure of default risk, focusing not only on balance sheet strength but also on the durability of cash flows derived from monopoly service territories, regulated rate recovery, and essential service demand.

Ratings agencies evaluate utilities using a blend of quantitative metrics, which include funds from operations (FFO) to debt, debt to capitalization ratios, interest coverage, and liquidity. Ratings agencies also use qualitative factors, which includes regulatory constructs, rate setting timeliness, cost recovery mechanisms, governance, and political risks. For public and regulated investor owned utilities alike, the predictability of regulatory outcomes, capital investment oversight, and treatment of extraordinary costs (e.g., wildfire, fuel price volatility, or decarbonization mandates) are central determinants of credit quality. The resulting rating, typically expressed on an investment grade to speculative grade scale, directly influences a utility's cost of capital, access to debt markets, and, in regulated contexts, the financial assumptions embedded in rates charged to customers.

These ratings are important because lower ratings equate to higher risks, higher costs of debt and reduced access to capital and credit. Higher ratings equate to lower risks and lower costs of debt. A solid credit rating directly benefits customers by reducing the immediate and future borrowing costs related to the financing needed to support regulatory obligations.

Q. Has PacifiCorp maintained investment grade credit ratings historically?

A. Yes. PacifiCorp has maintained investment grade credit since the utility was acquired by MidAmerican Energy in 2006, now BHE.

Q. Has PacifiCorp's business risks and credit ratings deteriorated in recent years?

A. Yes. PacifiCorp's credit ratings have materially deteriorated.[1]

Between June 2023 and March 2026, PacifiCorp experienced a series of credit rating downgrades driven largely by wildfire-related litigation, weakening financial metrics, and regulatory pressures. S&P first downgraded the company in June 2023 to BBB+ with a negative outlook due to wildfire exposure and fragile FFO to debt levels. Moody's followed in November 2023, lowering the issuer rating from A3 to Baa1 and senior secured from A1 to A2, citing deteriorating cash flow metrics and rising wildfire liabilities. The most significant impacts came in mid-2025, when Moody's downgraded PacifiCorp again to Baa2 in July, followed shortly by S&P dropping its issuer rating to BBB, both referencing weaker projected financial metrics, unfavorable regulatory outcomes, and litigation risks. By November 2025, S&P further lowered PacifiCorp to BBB- as accelerating wildfire damages trials increased surety bond and liquidity pressures, while Moody's affirmed Baa2 but warned of growing downgrade risk related to rising liquidity needs and has since changed its outlook to Negative. In early March 2026 S&P placed PacifiCorp on Credit Watch negative after a significantly large verdict was released in the *James* damage trial number 15.

[1] *E.g.,* "Workpaper – PacifiCorp Credit Ratings History".

A few weeks later S&P reversed that to Outlook Negative following two verdicts that were more in line with prior verdict amounts.[2] S&P listed factors that would lead the agency to lower its ratings for PacifiCorp "by one or more notches in the next 12 months," if: business risks increase from adverse legal, regulatory, or legislative developments; there is lower likelihood of support from BHE; wildfire liability from the *James* case significantly increases to roughly $10 million per plaintiff; PacifiCorp lacks liquidity to meet the collateral requirements for the *James* case class action verdicts; PacifiCorp's stand-alone FFO to debt remains consistently below 9 percent; or PacifiCorp contributes to another significant wildfire.[3]

Q. What are PacifiCorp's current credit ratings?

A. PacifiCorp's current ratings are shown in Table 3 below, and reflect PacifiCorp's current pressured financial position. Moody's assigns the company an A3 rating for Senior Secured Debt and a Baa2 issuer rating, both with a Stable outlook. S&P rates PacifiCorp's Senior Secured Debt at BBB+ and its issuer rating at BBB-. These ratings illustrate that while PacifiCorp remains investment grade, the company faces heightened scrutiny due largely to wildfire-related risks, trial bonding requirements, and weakening financial metrics.

[2] Confidential Exhibit PAC/301—"Research Update: PacifiCorp Ratings Removed from CreditWatch Negative, Outlook Negative," S&P Research Update, at 2 (Mar. 13, 2026).
[3] *Id.* at 2.

Table 3: Current PacifiCorp Credit Ratings

	Moody's	S&P's
Senior Secured Debt	A3	BBB+
Issuer	Baa2	BBB-
Outlook	Stable	Positive

Q. Can you discuss S&P's recent revised outlook to Positive?

A. Yes. In response to the *James* Oregon Court of Appeals decision, S&P revised PacifiCorp's outlook to positive.[4] This decision: "reflects the Court of Appeals' recent ruling and the likelihood we could upgrade PacifiCorp over the next several months if we determine PacifiCorp's wildfire-related liabilities will be materially reduced, PacifiCorp's short-term liquidity requirements are drastically lowered, or the *James* Case proceedings are significantly prolonged."[5]

However even the *James* appellate decision did not provide adequate evidence for S&P to upgrade PacifiCorp's credit.

Q. Why is it essential that PacifiCorp improve its current credit rating?

A. Credit ratings govern the prices that utilities pay for capital, the ability to attract the capital that is necessary to fund current and future operating needs, and the ability to transact in wholesale electric and natural gas markets.

[4] Confidential Exhibit PAC/302—"Research Update: PacifiCorp Outlook Revised to Positive Following Oregon Court of Appeals Decisions," S&P Global Ratings (Apr. 20, 2026).
[5] *Id.*

For example, many institutional investors have fiduciary responsibilities to their clients,[6] and are typically not permitted to purchase non-investment grade or junk (i.e., rated below BBB-/Baa3) securities, or in some cases even securities rated below a single A rating. PacifiCorp's current credit rating is only one step above non-investment grade or junk status. A further downgrade would materially shrink the pool of investors that PacifiCorp would have access to, and materially harm the ability of PacifiCorp to access the capital necessary to serve and make investments for Oregon customers.

Q. Has PacifiCorp's access to the credit markets changed since the company's last rate proceeding?

A. Yes. PacifiCorp has had reasonable access to the capital markets up until recent credit rating downgrades. Since that time, the company has maintained access to capital, however, the costs of that capital have increased, reflecting the risk associated with the wildfire liability and the ongoing operational risk. With the recent changes to PacifiCorp's credit rating outlook by S&P, from outlook negative to outlook credit watch negative and back to outlook negative in March 2026, it temporarily lost access to the junior subordinated note market. PacifiCorp's access to the commercial paper market was also limited and the company had to rely on its revolving credit facility for short-term borrowing.

[6] *E.g., SEC v. Capital Gains Research Bureau, Inc.*, 375 U.S. 180, 191–192 (1963) ("The Investment Advisers Act of 1940 thus reflects a congressional recognition "of the delicate fiduciary nature of an investment advisory relationship," as well as a congressional intent to eliminate, or at least to expose, all conflicts of interest which might incline an investment adviser—consciously or unconsciously—to render advice which was not disinterested.").

Q. Are there other examples in recent memory where utilities in the West were not able to access capital markets due to poor credit ratings?

A. Yes. The Great Recession of 2008-2009 provides a clear and compelling example of how poor credit ratings impact utility operations. During this period, PacifiCorp maintained strong credit ratings, and was able to issue new long-term debt during the midst of the financial turmoil. In contrast, other lower-rated utilities were shut out of the market, and could not obtain new or lower cost capital to fund operations. For example, in 2008 Arizona Public Service Company (rated Baa2/BBB- at that time) filed a letter with the Arizona Corporation Commission stating that the commercial paper market was completely closed to the utility, and it likely could not successfully issue long-term debt.[7]

Q. Are there additional customer benefits from maintaining healthy credit ratings?

A. Yes. PacifiCorp has a near constant need for short-term liquidity, as well as periodic long-term debt issuances. For example, PacifiCorp pays significant amounts daily to suppliers whom it counts on to provide necessary goods and services, such as fuel, energy, and inventory. Being unable to access funds can risk the ability to provide customers with energy, the successful completion of necessary and critical capital infrastructure projects, and would increase the chance of outages and service failures over the long term.

[7] *E.g., In re Arizona Public Service Company's Interim Rate Motion*, Docket No. E-01345, A-08-0172 (Oct. 17, 2008).

B. Weakened Credit Metrics

Q. Moving to credit metrics, what are they and why are they important?

A. Utility credit metrics are quantitative measures used by Moody's, S&P, and investors to evaluate a utility's ability to service debt on a sustained basis, given capital intensive utility operations and regulated cash flows. The two most typical utility credit metrics are pre-working capital cash flow divided by debt (CFO Pre-WC/Debt), and funds from operations divided by debt (FFO/Debt), which focus on recurring operating cash flows rather than accounting earnings.

These metrics assess the level of internally generated cash to support debt obligations, and help assess utility financial strength. Because utilities must fund large and ongoing capital investments while maintaining continuous access to capital markets, predictable cash-flow coverage is essential to credit stability. Credit ratings issue guidance, or a percentage range, for where they believe that utility-specific credit metrics should fall. When metrics fall outside these ranges, it raises downgrade risks. As a result, these metrics are often a leading indicator of credit downgrades, higher borrowing costs, or constrained financing flexibility for utilities.

Q. Please summarize PacifiCorp's historical and forecasted credit metrics.

A. Confidential Table 4 below presents PacifiCorp's CFO Pre-WC/Debt and FFO/Debt metrics from 2021 through 2026. The company's forecast metrics for 2026 are in the [redacted] range for Moody's and [redacted] range for S&P.

Confidential Table 4: PacifiCorp's Historical and Forecasted Credit Metrics

Credit Metric	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Forecast[8]
CFO Pre-WC/Debt (Moody's)[9]	21.4%	21.0%	9.6%	10.7%	15.0%	[redacted]
Moody's Guidance	19-20%	19-20%	16-17%	16-17%	>13.0%	[redacted]
FFO/Debt (S&P)[10]	21.9%	22.2%	16.7%	10.3%	10.5%	[redacted]
S&P Guidance	14-16%	14-16%	13-15%	13-15%	>11%	[redacted]

Q. What are your conclusions regarding PacifiCorp's historical and forecasted credit metrics?

A. Moody's and S&P have concluded that PacifiCorp's credit metrics have weakened materially from historical levels and are currently weak for the company's existing ratings. Both agencies have stated that cash-flow-to-debt metrics have limited headroom relative to downgrade thresholds, and that continued pressure could result in further negative rating action.

Moody's has noted that PacifiCorp's funds-from-operations-to-debt metrics have declined significantly from prior levels and reflect reduced financial flexibility, particularly in light of elevated wildfire-related liabilities and higher leverage. Similarly, S&P has stated that PacifiCorp's forecasted cash-flow-based metrics remain at the low end of, or below, the range typically associated with the current rating.

While both agencies recognize the stability of PacifiCorp's regulated utility operations, they have emphasized that meaningful and sustained improvement in credit

[8] Metric calculations based on PacifiCorp's proposed 50/50 capital structure in this case.
[9] For 2021 through 2025, CFO Pre-WC/Debt are from Moody's. For 2026, Moody's metrics are estimated by PacifiCorp. All years reflect adjustments for wildfire accruals, settlements, wildfire insurance and net power costs.
[10] For 2021 through 2025, FFO/Debt metrics are from S&P. For 2026, S&P metrics are estimated by PacifiCorp and reflect adjustments for wildfire accruals.

metrics supported by credit-positive regulatory outcomes and financial actions is necessary to stabilize the outlook and reduce the risk of further downgrade.

Q. Do you expect additional near-term financial pressures?

A. Yes, I expect several near-term financial pressures that leave PacifiCorp in challenging financial circumstances.

First, as noted above, PacifiCorp forecasts $7.9 billion in capital investments over the 2026 through 2028 timeframe. The company's planned investments include approximately $1.5 billion in wildfire mitigation efforts. These amounts are in addition to PacifiCorp's ongoing requirements to finance daily business operations.

Second, PacifiCorp will procure significant volumes of generation resources from two current solicitation processes (the 2025 Oregon Situs RFP, and the 2025 Washington Situs RFP). PacifiCorp is not seeking to own resources from these efforts, which would result in even more pressures on PacifiCorp's financial metrics, as ownership of resources requires a much larger near-term capital investment. However the volume of resources—multiple gigawatts—and resulting power purchase agreements that are contemplated from these processes will further strain PacifiCorp's weakened financial health. PacifiCorp would expect to execute these contracts well in advance of a final Commission decision in this proceeding.

Third, the ongoing war with Iran is a significant macroeconomic event that could have material impacts on western energy markets in the coming months. As approximately 20 percent of global oil, and 20-25 percent of liquified natural gas, passes through the Strait of Hormuz, reductions in this supply could materially impact

oil and natural gas prices in the West.[11] For example, gas resources are typically the marginal resource in many hours, in many locations, across the West.[12] Higher gas prices would result in higher real-time prices. Because PacifiCorp has an approximate 12-18 month delay to recover net power costs above approved baselines, this would further stress PacifiCorp's financial indicators.

Fourth, almost the entirety of PacifiCorp's service territory, including Oregon, Idaho, Utah, and Wyoming, set record low snow water equivalent readings for April 1st.[13] As NOAA observed, a March heat wave "shattered records across the Western United States," and was "the warmest March on record (since 1895) for Arizona, California, Colorado, Idaho, Utah, and Wyoming, and the second warmest record for Oregon."[14] This record weather followed "the warmest December-February on record (since 1895) in Arizona, Colorado, Nevada, New Mexico, Oregon, Utah, and Wyoming and the second warmest in California, Idaho, and Montana."[15] Oregon recently issued a drought emergency for Crook, Grant, Jackson, Jefferson, Morrow and Wallowa Counties.[16]

[11] *E.g.*, US EIA In-Brief Analysis, "Amid regional conflict, the Strait of Hormuz remains critical oil chokepoint," (Jun. 16, 2025) (available here: https://www.eia.gov/todayinenergy/detail.php?id=65504); US EIA In-Brief Analysis, "About one-fifth of global liquefied natural gas trade flows through the Strait of Hormuz" (Jun. 24, 2025) (available here: About one-fifth of global liquefied natural gas trade flows through the Strait of Hormuz - U.S. Energy Information Administration (EIA)).
[12] *E.g.*, "Q4 2025 Report on Market Issues and Performance," CAISO, at 7 (Mar. 30, 2026) ("Electricity prices in Western states typically follow natural gas price trends because gas-fired units are often the marginal source of generation in the Western Energy Imbalance Market (WEIM) balancing areas and other regional markets.") (available here: 2025-fourth-quarter-report-on-market-issues-and-performance.pdf).
[13] *E.g.*, "Snow Drought Current Conditions and Impacts in the West," NOAA National Integrated Drought Information System (Apr. 9, 2026) (available here: Snow Drought Current Conditions and Impacts in the West | April 9, 2026 | Drought.gov).
[14] *Id.*
[15] *Id.*
[16] Oregon Executive Order No. 26-07 (Apr. 21, 2026) (available here: eo-26-07.pdf).

These record-low snowpacks reduce regional hydropower reserves, and could lead to scarcity during the 2026 cooling season. As scarcity typically results in higher energy prices, this scarcity could increase PacifiCorp's net power costs. This delay in recovery of increased net power costs above approved baseline, as discussed above, would further stress PacifiCorp's financial indicators.

C. Impacts of the *James* Opinion

Q. Have there been any developments in the *James* case that are important to discuss?

A. As detailed by PacifiCorp witness Flynn, the company remains sensitive to the profound losses experienced by our communities. There are no winners in wildfires. However, PacifiCorp has continued to defend its interests in the *James* case, because of the belief that the trial court process and resulting decisions were fundamentally flawed. The Oregon Court of Appeals agreed, and recently overturned the initial 2023 verdict that held PacifiCorp liable for damages from four Oregon wildfires that occurred in 2020.

However the future is uncertain, because substantial litigation on heavily contested issues remains, with multiple competing and uncertain potential outcomes.

Q. Despite the *James* decision, will PacifiCorp continue to face financial headwinds?

A. Yes. As noted above, even the result from the *James* appeal was not enough for S&P to upgrade PacifiCorp's credit ratings, and instead only resulted in improving PacifiCorp's credit outlook to positive. Fundamentally, PacifiCorp requires several credit ratings upgrades to return to a healthy financial condition.

This is because wildfire liabilities are only one factor that credit agencies considered in PacifiCorp's recent ratings downgrades. Equally important are regulatory outcomes. As S&P stated when it downgraded PacifiCorp to BBB from BBB+: "The downgrade reflects our expectation that PacifiCorp's financial measures will be weaker than we previously forecast following its rate-case outcome in Utah."[17] This is because the Utah Public Service Commission approved approximately one quarter of PacifiCorp's original request, and S&P "previously expected a more-favorable outcome."[18]

Even PacifiCorp's best outcome in the *James* case will require several years and multiple credit ratings upgrades to address PacifiCorp's financial condition. Yet before that occurs, PacifiCorp faces immediate liquidity needs over the next 12-18 months.[19]

Q. What takeaway would you like to stress for the Commission?

A. PacifiCorp has significant liquidity challenges because of material capital investments over the next several years, concerns with potentially high net power costs because of record low snowpacks and uncertainty around significant wildfire litigation. When

[17] S&P Global Ratings, "Research Update: PacifiCorp Downgraded To 'BBB' From 'BBB+' On Weaker Expected Financial Measures, Outlook Negative; Debt Ratings Lowered," at 1 (Jul. 28, 2025).
[18] *Id.*
[19] *E.g.*, BHE 2025 Annual 10-K Report, at 77 ("PacifiCorp's litigation risk associated with the Wildfires and the potential impacts of CMO NO. 11 are inherently uncertain and the ultimate outcomes of the associated claims and the James appeals could materially and adversely affect PacifiCorp's financial condition and results of operations and its ability to obtain financing, to fund its operations, capital investments and settlements arising from the Wildfires.") (available here: 20251231_89_pc_annual_Form10-K.pdf); *In re PacifiCorp's Petition to Lower Common Equity Percentage to Less Than 44 Percent*, Docket No. UM 2406, Order No. 26-008 (Jan. 21, 2026); *In re PacifiCorp's Petition to Lower Common Equity Percentage to less than 44 Percent*, Docket UE-250727, Order 04 ¶ 50 (Jan. 28, 2026) ("Further, and more importantly, the record suggests that PacifiCorp's requested relief is the only and best available option to provide the liquidity needed at this time."); *Id.* ¶ 51 ("Further, we find that granting the Petition in in the public interest. The record reflects that PacifiCorp is in need of additional liquidity due to wildfire liabilities and ongoing capital commitments and operations.").

combined with PacifiCorp's credit ratings and metrics, PacifiCorp could easily experience future credit downgrades, which would reduce the company's access to the debt capital markets, increase costs, and harm PacifiCorp's ability to provide service and make investments necessary to support Oregon customers. Even with the recent *James* decision, these financial stressors will continue for several years.

As detailed below, PacifiCorp has instituted financial stabilization efforts to improve its finances, liquidity, and support credit metrics. PacifiCorp deeply appreciates the productive work from Commission Staff and the principled orders from the Commission in supporting the sale-leaseback of the Boardman-to-Hemingway project, and the direct engagement in helping PacifiCorp raise additional capital from the markets. Continued support from regulatory jurisdictions—like those steps provided by this Commission—must continue to be strong enough to ensure adequate liquidity over the next several years as PacifiCorp transitions back to a healthier, less leveraged capital structure.

V. FINANCIAL STABILIZATION EFFORTS

Q. What is the purpose of this section?

A. I discuss PacifiCorp's financial stabilization efforts that attempt to support adequate coverage ratios, with ratios in line with a BBB- rating. This financial plan builds cash to cover potential wildfire liabilities, provides liquidity for possible trial bonding and credit ratings support. When combined with the Commission's regulatory support in this and other proceedings, these efforts can help avoid future credit rating downgrades, and keep costs low for customers. Yet it is important to note that even these ambitious

efforts may not provide adequate support, and further downward pressure could be placed on PacifiCorp's credit metrics.

Q. What steps is the company taking to improve its financial metrics?

A. PacifiCorp and BHE are taking several actions to improve PacifiCorp's financial metrics. First, BHE suspended PacifiCorp's up-stream dividend beginning in June 2023 through at least the next several years, which will improve retained earnings and free-up available cash that can be used to fund the company's ongoing capital requirements. BHE also agreed to purchase PacifiCorp's share of the B2H line in a long-term sale-leaseback transaction, and provide a lease guarantee for the construction of certain Utah offices. Second, PacifiCorp has moved forward with the proposed sale of its Washington service territory, and a small portion of its Oregon service territory, to provide a near-term capital infusion and to simplify operations. Third, the company is reviewing its capital plans to restructure the timing and scope of its capital investments. Fourth, the company is proposing that the Commission authorize a common equity ratio of 50 percent. Finally, the company is proposing the Commission approve interim rates. I discuss each below.

A. BHE Support

Q. How is BHE providing support to PacifiCorp to improve its metrics?

A. While BHE does not impose a dividend requirement on PacifiCorp, historically PacifiCorp has paid dividends to BHE to manage the common equity component of PacifiCorp's capital structure.

In sustained periods of capital investment, PacifiCorp is able to instead retain these earnings to finance investments. If PacifiCorp had publicly traded common

equity, it would pay dividends on a consistent basis to attract investors to fund its business. These dividend payments would reasonably equate to approximately 60 to 70 percent of PacifiCorp's earnings. The flexibility of not paying a dividend on a quarterly basis in times of a significant capital investment cycle or in times of distress is a significant benefit. BHE's pledge that it will not require a dividend from PacifiCorp over the next five years will allow PacifiCorp to retain earnings to help finance wildfire settlements, capital investments, and overall cost of operations.[20]

Q. Is there additional BHE support you would like to highlight?

A. Yes. BHE has also provided support in the form of a sale-leaseback agreement for the Boardman to Hemingway transmission line to provide an alternative form of financing. PacifiCorp will be the operator of the project and keep transmission rights. A BHE subsidiary will fund the project and receive monthly lease payments from PacifiCorp. During the construction period, the BHE subsidiary will reimburse PacifiCorp for all construction costs, which are expected to total approximately $1.1 billion.

Q. Would PacifiCorp have entered into this agreement under more normal financial circumstances?

A. No. PacifiCorp decided to move forward with these transactions to support immediate near-term financing needs.

Q. Is there other BHE support you would like to discuss?

A. Yes. BHE recently agreed to a springing guarantee for a lease to support certain Utah office construction projects. This further improves PacifiCorp's financial health.

[20] *E.g.*, BHE 2025 Annual 10-K Report, at 74 ("As a result of material wildfire litigation at PacifiCorp, no dividends will be paid to BHE by PacifiCorp over the next several years . . .").

B. Service Territory Dispositions

Q. Can you discuss the company's recently announced service territory dispositions?

A. Yes. On February 17, 2026, PacifiCorp announced it had agreed to sell certain Washington-based generation and transmission assets and all of its Washington-based distribution assets, and infrastructure to Portland General Electric for $1.9 billion, subject to regulatory approvals and customary adjustments. This transaction represents a balance in addressing PacifiCorp's financial health and ensuring continuity of retained operations for the benefit of customers and employees.

In Oregon, distribution assets serving areas in Wallowa, Monroe and Lakeview will be sold to local operators committed to the communities they serve. Final agreements are currently being negotiated, and further underscores PacifiCorp's ongoing effort to strengthen its financial position and simplify operations.

C. Reduced Capital Expenditures

Q. How has the company revised its investment plans to support its credit profile?

A. PacifiCorp has reshaped its capital investment plan to alleviate near-term financial pressure while continuing to prioritize safety, reliability, and risk mitigation. Specifically, PacifiCorp has reduced planned capital expenditures over the 2024-2026 period, which directly improves leverage and cash-flow-based credit metrics. Within this lower overall spending profile, the company has reprioritized investments toward wildfire mitigation and core system reliability projects that reduce operational and financial risk. Together, these actions support improved near-term credit metrics, preserve liquidity, and help stabilize PacifiCorp's credit profile during a period of heightened risk.

D. Hypothetical Capital Structure

Q. What capital structure is PacifiCorp proposing for this general rate case?

A. PacifiCorp proposes a hypothetical capital structure reflecting 50 percent debt and 50 percent equity.

Q. Why is PacifiCorp proposing a hypothetical capital structure for this general rate case?

Given the material credit concerns noted above, the proposed hypothetical capital structure will better support PacifiCorp's financial health. This is similar to what was proposed in PacifiCorp's 2025 general rate case. The proposed hypothetical capital structure will demonstrate to the credit rating agencies and to the capital markets that the company has the regulatory support needed to improve its financial metrics to stabilize the outlook in the short term and improve credit ratings back to investment grade thereafter.

Q. What is the benefit to PacifiCorp's customers of providing support to the company in the form of a hypothetical capital structure?

A. As discussed above, PacifiCorp faces heightened risks of further credit rating downgrade (*e.g.,* PacifiCorp is currently rated BBB- by S&P), and one more downgrade would trigger PacifiCorp to be rated non-investment grade or junk. This would significantly affect PacifiCorp's access to capital markets, drive up the cost of debt, and impact the ability to transact in the wholesale electric and natural gas markets. To help maintain its current credit ratings and ensure access to reasonably priced capital—especially during a period of significant system investment—the company is

seeking a ratemaking capital structure that strengthens its financial profile and benefits customers.

Providing regulatory support through the proposed hypothetical capital structure will lower the company's overall risk profile and, in turn, reduce financing costs borne by customers. Without consistent access to capital markets at reasonable costs, the company's borrowings—and the associated costs of constructing new facilities—will increase. In extreme circumstances, restricted access to financing could jeopardize the timely completion of critical projects, impair safe and reliable system operations, and create significant liquidity challenges.

Q. How does PacifiCorp's historical actual capital structure compare to what is currently authorized?

A. PacifiCorp's historical capital structure over the 2019–2025 period reflects a clear shift toward higher leverage to fund wildfire related liabilities, capital investment needs and liquidity needs to support wildfire trial bonding and credit ratings. While the company maintained an equity ratio just above 50 percent from 2019 through 2022, that ratio declined sharply beginning in 2023, falling to 43.16 percent by 2025 as long-term debt levels rose from 48.36 percent in 2019 to 56.84 percent in 2025. Preferred stock remained immaterial throughout, at approximately 0.01 percent each year and was called in 2025 so it is no longer a part of PacifiCorp's capital structure. The trend demonstrates that, although PacifiCorp historically operated with higher equity levels to support its capital structure, recent pressures have resulted in a more highly leveraged balance sheet. It will take a few years for PacifiCorp to return to a more balanced capital structure and a return to investment-grade credit ratings, and adoption

of a hypothetical capital structure in this rate case will help to stabilize PacifiCorp's financial condition in the near term.

Table 5: Historical Actual Capital Structure[21]

As of December 31:	2019	2020	2021	2022	2023	2024	2025
Long-Term Debt	48.36%	48.49%	47.69%	46.69%	49.95%	56.52%	56.84%
Preferred Stock	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%	0.0%
Common Equity	51.62%	51.50%	52.30%	53.30%	50.04%	43.47%	43.16%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Q. What is PacifiCorp's forecasted capital structure?

A. Through 2022, the company managed a capital structure above the authorized level, and it was not until the recent events related to the 2020 wildfires, and results from the recent Utah rate case, that the equity ratio dropped below the authorized level to 50 percent. As a result of incremental wildfire liability accruals throughout 2023, and multiple settlements in 2023-2025, coupled with the company's sizable capital expenditure plan and liquidity needs, PacifiCorp's actual capital structure has become, and will continue to be for the foreseeable future, more highly leveraged. As a result, the company's financial risk has increased significantly. Table 6 presents PacifiCorp's forecasted actual capital structure for 2026 and 2027.

Table 6: Forecasted Capital Structure[22]

Forecast as of December 31	2026	2027
Long-Term Debt	60.20%	59.70%
Common Equity	39.80%	40.30%
Total	100.00%	100.00%

[21] Five quarter-end average percentage Capital Structure for trailing 12-month period ending December 31 of each period.

[22] Five quarter-end average percent Capital Structure for 12-month period ending December 31 of each period. The Company's Preferred Stock was called in January 2025 and is no longer part of the capital structure.

Q. Is there precedent in Oregon for using a hypothetical capital structure that differs from a company's actual structure?

A. Yes. Most recently, in Order No. 24-447 resolving PacifiCorp's last general rate case and in Order No. 24-454 resolving a PGE general rate case, the Commission explained, "While the actual debt-equity ratio remains up to the company's management, using a hypothetical capital structure in ratemaking ensures that rates are set with an overall cost of capital based on an optimal debt-to-equity ratio."[23] The Commission noted this had been its practice in PacifiCorp's prior two general rate cases and endorsed a hypothetical 50/50 capital structure specifically, stating, "Using a hypothetical capital structure for ratemaking—regardless of whether the actual proportion of equity to debt is lower than the 50/50 hypothetical or higher than the 50/50 hypothetical, as it was in PacifiCorp's last general rate case—provides a consistent regulatory signal that a balanced structure supports the long-term best interests of utility ratepayers."[24] In the PGE case, the Commission found persuasive that PGE was working toward a 50/50 capital structure and expressed concern that changing PGE's capital structure "would be interpreted negatively by the ratings agencies, as an indication of lack of regulatory support for PGE's efforts to return to a more balanced position."[25]

[23] *In re PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 433, Order No. 24-447 at 7 (Dec. 19, 2024); *accord In re Portland General Electric Company Request for a General Rate Revision*, Docket No. UE 435, Order No. 24-454 at 13 (Dec. 20, 2024).
[24] Order No. 24-447 at 7; *accord* Order No. 24-454 at 13.
[25] Order No. 24-454 at 13-14.

Q. Is there precedent from other jurisdictions for using a hypothetical capital structure that differs from a company's actual structure?

A. Yes. Multiple regulatory commissions, including those in Utah, Washington, Wyoming, Alaska, Utah, Louisiana, and the Federal Energy Regulatory Commission (FERC), have approved hypothetical capital structures to support utility financial integrity under certain circumstances.

For example, Utah has previously approved a hypothetical capital structure for PacifiCorp based on comparable utility capitalizations used for return on equity analysis.[26] Washington has concluded that a hypothetical capital structure may be appropriate in circumstances, such as financial hardship or tight capital market conditions.[27] Wyoming approved a stipulated hypothetical capital structure, finding it reasonable and consistent with industry norms when a utility had weakened financial metrics.[28] Alaska routinely authorizes hypothetical capital structures when a utility's equity ratio is impaired, allowing utilities to increase equity levels to restore financial stability and support investment-grade credit ratings.[29] Louisiana does so to help

[26] *In re PacifiCorp's 1999 Rate Case,* Docket No. 99-035-10, Report and Order (May 24, 2000).
[27] *In re Avista's 2017 Washington Rate Case,* Docket Nos. UE-170485 and UG-170486, Order 07, ¶ 110 (Apr. 26, 2018) ("A hypothetical capital structure should also be reserved for circumstances including, but not limited to, financial hardship or tight capital market conditions. In this case, we do not find either of these circumstances present to justify a hypothetical capital structure.").
[28] *In re Cheyenne Light's 2007 Rate Case*, Docket No. 20003-90-ER-07 (Record No. 11070), Memorandum Opinion, Findings and Order Approving Stipulation, ¶ 100 (May 2, 2008) ("The stipulated hypothetical Cheyenne Light capital structure comprised of 54% equity and 46% debt is reflective of typical capital structures and industry norms for public utilities similar to Cheyenne Light, and is consistent with the representations by Cheyenne Light's witnesses that it is the Company's intent to move its actual capital structure to a 54%/46% ratio by January 1, 2008. . . . In making this request, the Commission is cognizant that the actual capital structure of a Company is dynamic and subject to its changing financing and capital requirements.").
[29] *E.g., In re Anchorage Municipal Light and Power's 1987 and 1999*, Docket Nos. U-87-84, U-99-139, U-10-31, and U-10-31, Order No. 15, at 7 (using a hypothetical capital structure in each case, eventually raising common equity ratio to 40.4 percent); *In re AMLP's 2005 Rate Case,* Docket No. U-05-86, U-10-21, Order No. 15 (indicating hypothetical capital structure no longer needed as it had investment-grade bond ratings).

improve utility credit ratings that are not investment grade.[30] Similarly FERC allows hypothetical capital structures in many circumstances, including to improve access to capital markets for transmission investments, for specific projects when necessary for project financing, and more recently, to support credit quality for large transmission investments,[31] especially when doing so will help maintain a utility's current credit rating to support these goals.[32]

Q. What conclusion can be drawn from regulatory precedent?

A. While actual capital structures are generally preferred, regulatory precedent supports the use of a hypothetical capital structure when needed to maintain credit quality and access to capital, which ultimately benefits customers.

E. Interim Rates

Q. Why is PacifiCorp requesting interim rates in this proceeding?

A. PacifiCorp faces unprecedented financial headwinds, and this request is necessary to enable PacifiCorp to access the capital that is required to continue to serve and invest in Oregon's utility system and meet the policy goals of this state. Company witness Link describes in greater detail the standard for reviewing an interim rate request. While I am not a lawyer, my understanding is that PacifiCorp must be in dire financial circumstances and show a compelling need for interim relief. As I have described above and discuss in more detail below, PacifiCorp meets this standard.

[30] *In re Gulf States Utilities Company's 2003 Louisiana Rate Case*, Docket NO. U-17282, Order No. U-17282-C, at 5 (Feb. 4, 2004).
[31] *In re FERC Promoting Transmission Investment through Pricing Reform*, Docket No. RM06-4-000, Order No. 679, ¶¶ 131-134 (July 20, 2006).
[32] *In re Missouri River Energy's Big Stone Project*, Docket No. ER23-2284-000, Order on Transmission Rate Incentives, ¶ 21 (Aug. 31, 2023).

Q. How will PacifiCorp's proposal for interim rates improve PacifiCorp's immediate liquidity needs?

A. Interim rates will immediately improve PacifiCorp's liquidity and cash flow concerns by reducing the regulatory lag for costs that PacifiCorp is already incurring to serve Oregon customers.

For example, despite PacifiCorp's efforts to reduce capital, the company forecasts approximately $2.9 billion in capital expenditures in 2026, above what is currently included in PacifiCorp's Oregon revenue requirement. Absent interim rate relief, PacifiCorp would not be able to begin recovering these expenditures until after a Commission decision in this proceeding (reasonably on or after April 5, 2027). PacifiCorp's $55.1 million interim rate increase will provide an immediate cashflow and liquidity buffer for these capital expenditures, and improve PacifiCorp's credit metrics.

Q. What are the implications if an interim rate increase is not approved now?

A. If interim rates are not approved at this time, PacifiCorp may need to evaluate its capital plan, which could include deferring or canceling certain capital projects, including initiatives to support Oregon's energy policy goals and major transmission projects. Further, PacifiCorp is in the process of acquiring numerous power purchase agreements to meet Oregon's clean energy mandates. These agreements will place pressure on the company's already weakened credit metrics, and interim rates will help offset this downward pressure to the company's credit metrics.

Q. How will a $55.1 million interim rate increase benefit PacifiCorp's credit metrics by increasing cashflow and liquidity?

A. As noted in the table below, interim rates are expected to positively impact PacifiCorp's CFO Pre-WC/Debt and FFO/Debt metrics. Both PacifiCorp's CFO Pre-WC/Debt credit metric and FFO/Debt could increase by 10 basis points with the additional cashflow produced by interim rates.

Table 7: Forecasted Capital Structure

Credit Metric	2024 Actual	2025 Actual	2026 Forecast w/out Interim Rates[33]	2026 Forecast w/Interim Rates
CFO Pre-WC/Debt (Moody's)[34]	[redacted]	[redacted]	[redacted]	[redacted]
Moody's Guidance	[redacted]	[redacted]	[redacted]	[redacted]
FFO/Debt (S&P)[35]	[redacted]	[redacted]	[redacted]	[redacted]
S&P Guidance	[redacted]	[redacted]	[redacted]	[redacted]

Q. Will any of the other financial stabilization efforts discussed above provide the same type of immediate relief as interim rates?

A. Not necessarily. All the efforts discussed above have provided, or will provide if approved, relief by increasing PacifiCorp's liquidity, which is viewed positively by rating agencies and PacifiCorp's auditors. However, the liquidity benefits of several efforts—like the service territory dispositions and hypothetical capital structure—will

[33] Metric calculations based on PacifiCorp's proposed 50/50 capital structure in this case.
[34] For 2024 through 2025, CFO Pre-WC/Debt are from Moody's. For 2026, Moody's metrics are estimated by PacifiCorp. All years reflect adjustments for wildfire accruals, settlements, wildfire insurance and net power costs.
[35] For 2024 through 2025, FFO/Debt metrics are from S&P. For 2026, S&P metrics are estimated by PacifiCorp and reflect adjustments for wildfire accruals.

materialize only after approval, which is not expected until 2027. Given PacifiCorp's future uncertainty due to continuing wildfire litigation, the efforts discussed above may not be sufficient to avoid future downgrades or may come too late to prevent a future downgrade. For purposes of the immediate near-term, PacifiCorp's 2.8 percent interim rate request as the primary tool to address PacifiCorp's immediate financial circumstances.

Q. Why is it important that the Commission approve PacifiCorp's requests?

A. Further downgrades could result in PacifiCorp being "unable to secure sufficient debt financings or alternative funding sources to support ongoing operations, including the ability to absorb wholesale power volatility, pay suppliers and meet debt obligations, and such liquidity issues may impact transmission and generation development, purchasing power in the market, building and upgrading substations, connecting new customers, addressing outages and maintaining system resilience."[36] Without immediate and durable regulatory support—in the immediate near term in the form of interim rates—there is a real possibility that PacifiCorp "may be unable to obtain the necessary funding to meet its liquidity needs."[37]

VI. LONG-TERM DEBT COST CALCULATIONS

Q. How did you calculate the company's embedded costs of long-term debt?

A. I have calculated the embedded costs of debt over the calendar year 2027 test period (Test Period), using an average of long-term debt percentage costs of PacifiCorp's five quarter-ending balances, spanning the 12-month period ending December 31, 2027,

[36] BHE 2025 10-K, at 77.
[37] *Id.*

based on known and measurable changes through December 31, 2026. PacifiCorp's proposed capital structure is a hypothetical capital structure set at a level to enable the company to maintain its current credit ratings.

Q. Please explain the cost of long-term debt calculation.

A. I calculated the cost of debt by issue, based on each debt series' interest rate and net proceeds at the issuance date, to produce a bond yield to maturity for each series of debt outstanding as of each of the five quarter-ending dates spanning the Test Period. In the event a bond was issued to refinance a higher cost bond, the pre-tax premium and unamortized costs, if any, associated with the refinancing were subtracted from the net proceeds of the bonds that were issued. Each bond yield was then multiplied by the principal amount outstanding of each debt issue, resulting in an annualized cost of each debt issue. Aggregating the annual cost of each debt issue produces the total annualized cost of debt. Dividing the total annualized cost of debt by the total principal amount of debt outstanding produces the weighted average cost for all debt issues.

Q. What type of debt does PacifiCorp use in meeting its financing requirements?

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. Exhibit PAC/303—Pro forma Cost of Long-Term Debt, shows that, over the test period, PacifiCorp is projected to have an average of approximately $18.15 billion of long-term debt outstanding, with an average cost of 5.41 percent. Presently, all outstanding first mortgage bonds bear interest at fixed rates. Additionally, PacifiCorp has issued junior subordinated notes which have five-year call features, can have an ultimate maturity of 30, and have interest rate reset features every five to ten years with

the interest rate being fixed between the reset periods. Proceeds from the issuance of the first mortgage bonds (and other financing instruments) are used to finance the utility operation.

Q. What is PacifiCorp's embedded cost of long-term debt?

A. PacifiCorp's cost of long-term debt is 5.41 percent.[38]

VII. CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. I respectfully request the Commission adopt PacifiCorp's proposed capital structure with a common equity level of 50.00 percent, and approve PacifiCorp's request for interim rates.

The Commission's approval of both measures will send an important message to the financial community and bolster Oregon's regulatory support for PacifiCorp. When combined with PacifiCorp's other financial stabilization efforts, including suspended dividends to increase retained earnings and a restructuring of the company's capital investments, among others, will provide the necessary financial support and risk mitigation necessary to support the company's credit metrics and credit ratings. Reviewing PacifiCorp's history demonstrates that a financially strong company provides positive financial benefits to customers in the form of access to capital on reasonable terms, which is vital given ongoing need for critical capital investments over the next several years, despite efforts to reduce capital spending.

[38] Exhibit PAC/303—Pro Forma Cost of Long-Term Debt.

With PacifiCorp's updated cost of long-term debt of 5.41 percent and the cost of equity of 9.70 percent, this produces a reasonable overall cost of capital of 7.56 percent.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 470
Exhibit PAC/301
Witness: M. Ryan Weems

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of M. Ryan Weems

S&P Global Ratings, "Research Update: PacifiCorp Ratings Removed from CreditWatch Negative, Outlook Negative"

May 2026

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

REDACTED
Docket No. UE 470
Exhibit PAC/302
Witness: M. Ryan Weems

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of M. Ryan Weems

"Research Update: PacifiCorp Outlook Revised to Positive Following Oregon Court of Appeals Decisions"

May 2026

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

Docket No. UE 470
Exhibit PAC/303
Witness: M. Ryan Weems

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of M. Ryan Weems

Pro Forma Cost of Long-Term Debt

May 2026

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Summary
12 months ended December 31, 2027

LINE NO.	DESCRIPTION	AMOUNT 5QE AVE OUTSTANDING	(DISC)/PREM & ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	LINE NO.
1										1
2	**Total First Mortgage Bonds**	**$16,200,000,000**	**($170,229,527)**	**($1,295,995)**	**$16,028,474,478**	**$839,318,500**	**5.086%**	**5.181%**	**22.1**	2
3	**Total Junior Subordinated Debt**	**$1,950,000,000**	**($20,719,996)**	**$0**	**$1,929,280,004**	**$142,765,000**	**7.234%**	**7.321%**	**30.5**	3
4	Loss on Long Term Debt Reacquistions, without Refunding					$108,611				4
5	**Total Cost of Long Term Debt**	**$18,150,000,000**	**($190,949,523)**	**($1,295,995)**	**$17,957,754,482**	**$982,192,111**	**5.317%**	**5.412%**	**23.0**	5
6										6

PACIFICORP
Electric Operations
Pro-Forma Cost of Long-Term Debt Detail
12 months ended December 31, 2027

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT 5QE AVE OUTSTANDING	(DISC)/PREM & ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1														1
2														2
3	5.100%	Series due Feb 2029	01/05/24	02/15/29	5	$500,000,000	$500,000,000	($2,522,458)	$0	$497,477,542	$99.496	5.212%	$26,060,000	3
4	4.250%	Series due Feb 2029	02/06/26	03/15/29	3	$400,000,000	$400,000,000	($2,172,000)	$0	$397,828,000	$99.457	4.438%	$17,752,000	4
5	4.650%	Series due Apr 2029	03/25/26	04/15/29	3	$300,000,000	$300,000,000	($1,527,209)	$0	$298,472,791	$99.491	4.830%	$14,490,000	
6	3.500%	Series due Jun 2029	03/01/19	06/15/29	10	$400,000,000	$400,000,000	($2,874,181)	$0	$397,125,819	$99.281	3.584%	$14,336,000	6
7	2.700%	Series due Sep 2030	04/08/20	09/15/30	10	$400,000,000	$400,000,000	($2,876,791)	$0	$397,123,209	$99.281	2.780%	$11,120,000	7
8	5.300%	Series due Feb 2031	01/05/24	02/15/31	7	$700,000,000	$700,000,000	($4,873,442)	$0	$695,126,558	$99.304	5.418%	$37,926,000	8
9	5.100%	Series due Apr 2031	03/25/26	04/15/31	5	$550,000,000	$550,000,000	($2,614,316)	$0	$547,385,684	$99.525	5.207%	$28,638,500	
10	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	$98.766	7.807%	$23,421,000	10
11	5.450%	Series due Apr 2033	03/25/26	04/15/33	7	$800,000,000	$800,000,000	($5,328,212)	$0	$794,671,788	$99.334	5.565%	$44,520,000	
12	5.450%	Series due Feb 2034	01/05/24	02/15/34	10	$1,100,000,000	$1,100,000,000	($8,271,408)	$0	$1,091,728,592	$99.248	5.547%	$61,017,000	12
13	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	$98.693	5.994%	$11,988,000	13
14	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	$300,000,000	$300,000,000	($3,992,021)	($1,295,995)	$294,711,984	$98.237	5.369%	$16,107,000	14
15	5.800%	Series due Apr 2036	03/25/26	04/15/36	10	$850,000,000	$850,000,000	($7,165,263)	$0	$842,834,737	$99.157	5.912%	$50,252,000	
16	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	$350,000,000	$350,000,000	($4,048,881)	$0	$345,951,119	$98.843	6.185%	$21,647,500	16
17	5.750%	Series due Apr 2037	03/14/07	04/01/37	30	$600,000,000	$600,000,000	($613,216)	$0	$599,386,784	$99.898	5.757%	$34,542,000	17
18	6.250%	Series due Oct 2037	10/03/07	10/15/37	30	$600,000,000	$600,000,000	($5,877,281)	$0	$594,122,719	$99.020	6.323%	$37,938,000	18
19	6.350%	Series due Jul 2038	07/17/08	07/15/38	30	$300,000,000	$300,000,000	($3,961,333)	$0	$296,038,667	$98.680	6.450%	$19,350,000	19
20	6.000%	Series due Jan 2039	01/08/09	01/15/39	30	$650,000,000	$650,000,000	($12,309,687)	$0	$637,690,313	$98.106	6.139%	$39,903,500	20
21	4.100%	Series due Feb 2042	01/06/12	02/01/42	30	$300,000,000	$300,000,000	($3,724,911)	$0	$296,275,089	$98.758	4.173%	$12,519,000	21
22	4.125%	Series due Jan 2049	07/13/18	01/15/49	31	$600,000,000	$600,000,000	($6,984,085)	$0	$593,015,915	$98.836	4.193%	$25,158,000	22
23	4.150%	Series due Feb 2050	03/01/19	02/15/50	31	$600,000,000	$600,000,000	($7,938,771)	$0	$592,061,229	$98.677	4.227%	$25,362,000	23
24	3.300%	Series due Mar 2051	04/08/20	03/15/51	31	$600,000,000	$600,000,000	($10,127,937)	$0	$589,872,063	$98.312	3.388%	$20,328,000	24
25	2.900%	Series due June 2052	07/09/21	06/15/52	31	$1,000,000,000	$1,000,000,000	($16,599,374)	$0	$983,400,626	$98.340	2.982%	$29,820,000	25
26	5.350%	Series due Dec 2053	12/01/22	12/01/53	31	$1,100,000,000	$1,100,000,000	($13,367,772)	$0	$1,086,632,228	$98.785	5.431%	$59,741,000	26
27	5.500%	Series due May 2054	05/17/23	05/15/54	31	$1,200,000,000	$1,200,000,000	($11,660,929)	$0	$1,188,339,071	$99.028	5.566%	$66,792,000	27
28	5.800%	Series due Jan 2055	01/05/24	01/15/55	31	$1,500,000,000	$1,500,000,000	($22,482,375)	$0	$1,477,517,625	$98.501	5.906%	$88,590,000	28
29	**5.086%**	**Total First Mortgage Bonds**			**22**		**$16,200,000,000**	**($170,229,527)**	**($1,295,995)**	**$16,028,474,478**		**5.181%**	**$839,318,500**	29
30														30
31														31
32	7.375%	Fixed-to-Fixed Reset Rate JSN due 2055	03/20/25	09/15/55	30	$850,000,000	$850,000,000	($9,054,996)	$0	$840,945,004	$98.935	7.464%	$63,444,000	32
33	7.125%	Fixed-to-Fixed Reset Rate JSN due 2056	02/05/26	08/15/56	31	$1,100,000,000	$1,100,000,000	($11,665,000)	$0	$1,088,335,000	$98.940	7.211%	$79,321,000	33
34	**7.234%**	**Total Junior Subordinated Debt**			**31**		**$1,950,000,000**	**($20,719,996)**	**$0**	**$1,929,280,004**		**7.321%**	**$142,765,000**	34
35														35
36			**REACQ DATE**	**ORG MAT DATE**										36
37														37
38		8.375% Series A QUIDS	11/17/00	06/30/35									$108,611	38
39		**Long-Term Debt Reacquisition, without refunding amortization**											**$108,611**	39
40														40
41	**5.317%**	**Total Long-Term Debt**			**23**		**$18,150,000,000**	**($190,949,523)**	**($1,295,995)**	**$17,957,754,482**		**5.412%**	**$982,192,111**	41
42														42

Docket No. UE 470
Exhibit PAC/400
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Ann E. Bulkley

May 2026

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ATTACHED EXHIBITS

Exhibit PAC/401—Resume and Testimony Listing of Ann E. Bulkley

Exhibit PAC/402—Summary of Results

Exhibit PAC/403—Proxy Group Selection

Exhibit PAC/404—Constant Growth Discounted Cash Flow Model

Exhibit PAC/405—Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

Exhibit PAC/406—Long-Term Beta Coefficient

Exhibit PAC/407—Market Return

Exhibit PAC/408—Risk Premium Approach

Exhibit PAC/409—Multi-Stage Discounted Cash Flow Model

Exhibit PAC/410—Gross Domestic Product Growth

Exhibit PAC/411—Capital Expenditures Analysis

Exhibit PAC/412—Regulatory Risk Analysis

Exhibit PAC/413—Regulatory Research Associates Ranking Analysis

Exhibit PAC/414—S&P Credit Supportiveness Ranking Analysis

Exhibit PAC/415—Capital Structure Analysis

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. I am a Principal at The Brattle Group (Brattle). My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this direct testimony before the Public Utility Commission of Oregon (Commission) on behalf of PacifiCorp d/b/a/ Pacific Power, which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company (BHE).

Q. Please describe your background and professional experience in the energy and utility industries.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with over 30 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. My resume and a summary of testimony that I have filed in other proceedings, including previously before the Commission, are included as Exhibit PAC/401 to this testimony.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the appropriate return on equity (ROE) for PacifiCorp's electric utility operations in Oregon and to provide an assessment of its proposed capital structure to be used for ratemaking purposes.

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. I have estimated the market-based cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the discounted cash flow (DCF) model, the capital asset pricing model (CAPM), the empirical capital asset pricing model (ECAPM), and a bond yield risk premium (BYRP or risk premium) analysis. My recommendation also takes into consideration the business and regulatory risk of the company relative to the proxy group, and PacifiCorp's proposed capital structure as compared with the capital structures of the operating utilities of the proxy group companies. While I do not make specific adjustments to my ROE recommendation for these factors, I do consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results

Q. How is the remainder of your direct testimony organized?

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

- Section III provides a summary of my analyses and conclusions.
- Section IV reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section V discusses current and prospective capital market conditions and the effect of those conditions on the company's cost of equity.
- Section VI explains my selection of the proxy group.
- Section VII describes my cost of equity analyses and the basis for my recommended ROE in this proceeding.

- Section VIII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the company in this case.
- Section IX provides an assessment of the reasonableness of the company's proposed capital structure.
- Section X presents my conclusions and recommendations.

III. SUMMARY OF ANALYSES AND CONCLUSIONS

Q. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A. My analyses and recommendations consider the following:

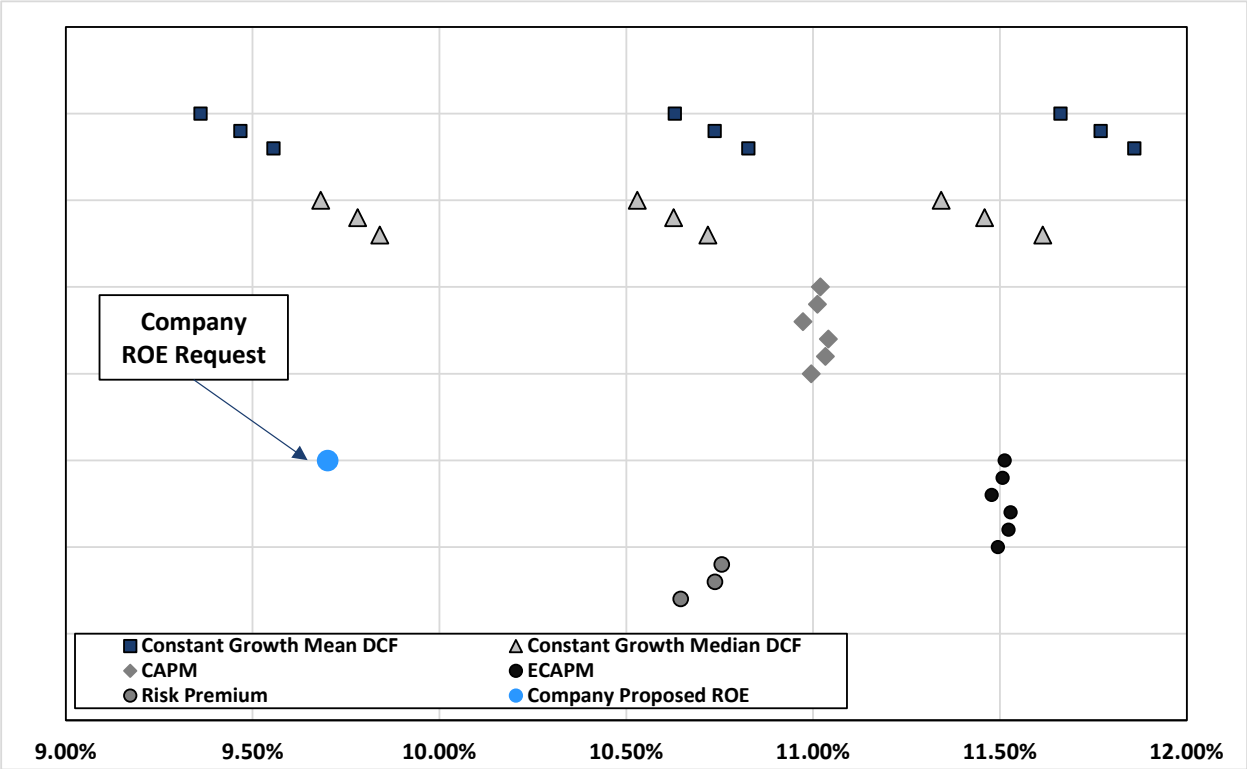
- The United States (U.S.) Supreme Court's *Hope* and *Bluefield* decisions[1] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.
- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.
- The results of several analytical approaches that provide estimates of the company's cost of equity. Because the company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis.)
- Although the companies in my proxy group are generally comparable to PacifiCorp, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I considered PacifiCorp's regulatory, business, and financial risks relative to a proxy group of comparable companies in determining where the company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

[1] 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).

Q. What are the results of the models that you have used to estimate the market-based cost of equity for PacifiCorp?

A. Figure 1 summarizes the range of results produced by the cost of equity analyses based on data through the end of February 28, 2026.

Figure 1: Summary of Cost of Equity Analytical Results[2]



Q. What is PacifiCorp's requested ROE in the proceeding?

A. PacifiCorp has risk factors that are likely considered by investors, that taken together, support an ROE above the mean of this range. However, the company is requesting a return on equity of 9.70 percent which is at the low end of the range of results summarized in Figure 1 and is intended to recognize the significant rate pressures

[2] See also PAC/402.

affecting its customers and balance the impact on customers with the need for the company to recover costs necessary to continue to provide safe, reliable service.[3]

Q. Is the company's requested capital structure reasonable?

A. Yes. The company's proposed equity ratio of 50.00 percent is well within the range of the actual capital structures of the utility operating subsidiaries of the proxy group companies. Further, the company's proposed equity ratio is reasonable considering recent ratings determinations that are discussed more thoroughly by witness Weems including a negative outlook from Moody's Investors Service (Moody's) and a recently issued positive outlook from Standard & Poor's (S&P).

IV. REGULATORY GUIDELINES

Q. Please describe the principles that guide the establishment of the cost of capital for a regulated utility.

A. The U.S. Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[4]

[3] Direct Testimony of company witness Rick T. Link, at 8.
[4] *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes. The Commission follows the precedents of the *Hope* and *Bluefield* cases by acknowledging that utility investors are entitled to a fair and reasonable return. For example, in the Commission's determination in PacifiCorp's 2025 general rate case it stated:

> As articulated in compensation if they provide "adequate revenue both for operating expenses of the public utility * * * and for capital costs of the utility, with a return to the equity holder that is: (a) Commensurate with the return on investments in other enterprises having corresponding risks; and (b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[5]

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.

Q. Why is it important for a utility to be allowed the opportunity to earn a return that is adequate to attract capital at reasonable terms?

A. A return that is adequate to attract capital at reasonable terms enables the company to continue to provide safe, reliable electricity service while maintaining its financial integrity. That return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the company's ability to attract capital at reasonable cost, which negatively affects customers.

[5] In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision, Docket No. UE 433, Order No. 24-447 at 6 (Dec. 19, 2024).

Q. Is a utility's ability to attract capital also affected by the ROEs authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other electric, natural gas, and water utilities nationally. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk within that jurisdiction generally, and for that utility particularly. The cost of capital represents an opportunity cost to investors. If higher returns are available elsewhere for other investments of comparable risk over the same time period, investors have an incentive to direct their capital to those alternative investments.

Q. What is the standard for setting the ROE in any jurisdiction?

A. The stand-alone ratemaking principle is the foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. In order to maintain this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for PacifiCorp's electric operations in Oregon.

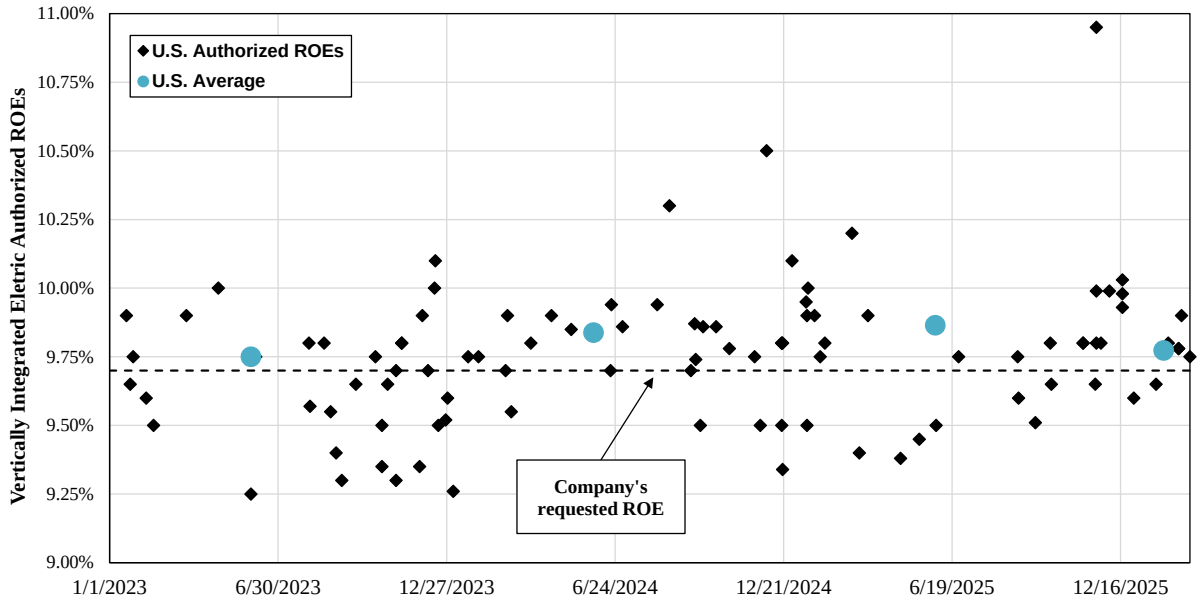
Q. Does the fact that the PacifiCorp is a subsidiary of BHE, a publicly-traded company, affect your analysis?

A. No. In this proceeding, consistent with stand-alone ratemaking principles, it is appropriate to establish the cost of equity for PacifiCorp, not its publicly traded entity, BHE. More importantly, however, it is appropriate to establish a cost of equity and capital structure that provide PacifiCorp the ability to attract capital on reasonable terms on a stand-alone basis and within BHE.

Q. How does PacifiCorp's requested ROE compare with recently authorized ROEs for vertically integrated electric utilities?

A. As shown in Figure 2, the company's requested ROE of 9.70 percent is well within the range of recently authorized ROEs for vertically integrated electric utilities.

Figure 2: Authorized ROEs for Vertically-Integrated Electric, January 2023 – February 2026



Q. Are the regulatory framework and the authorized ROE and equity ratio important to the financial community?

A. Yes. The regulatory framework is one of the most important factors in investors' assessments of risk. Specifically, the authorized ROE and equity ratio for regulated utilities is very important for determining the degree of regulatory support for supporting a utility's creditworthiness and financial stability in the jurisdiction. To the extent that authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, such actions are considered by both debt and equity investors in the overall risk assessment of the regulatory jurisdiction in which the company operates.

Q. What are your conclusions regarding regulatory guidelines?

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide PacifiCorp with a reasonable opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions.

Providing the opportunity to earn a market-based cost of capital supports the financial integrity of PacifiCorp, which is in the interest of both customers and shareholders.

V. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. The models used to estimate the cost of equity rely on market data and thus the results of those models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, including stock prices, dividends, growth rates, and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the cost of equity estimation models. As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE, and the ROE to be used for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is important to consider projected market data to estimate the return for that forward-looking period.

Q. What has the level of inflation been over the past few years?

A. As shown in Figure 3, core inflation increased steadily beginning in early 2021, rising from 1.40 percent in January 2021 to a high of 6.64 percent in September 2022, which

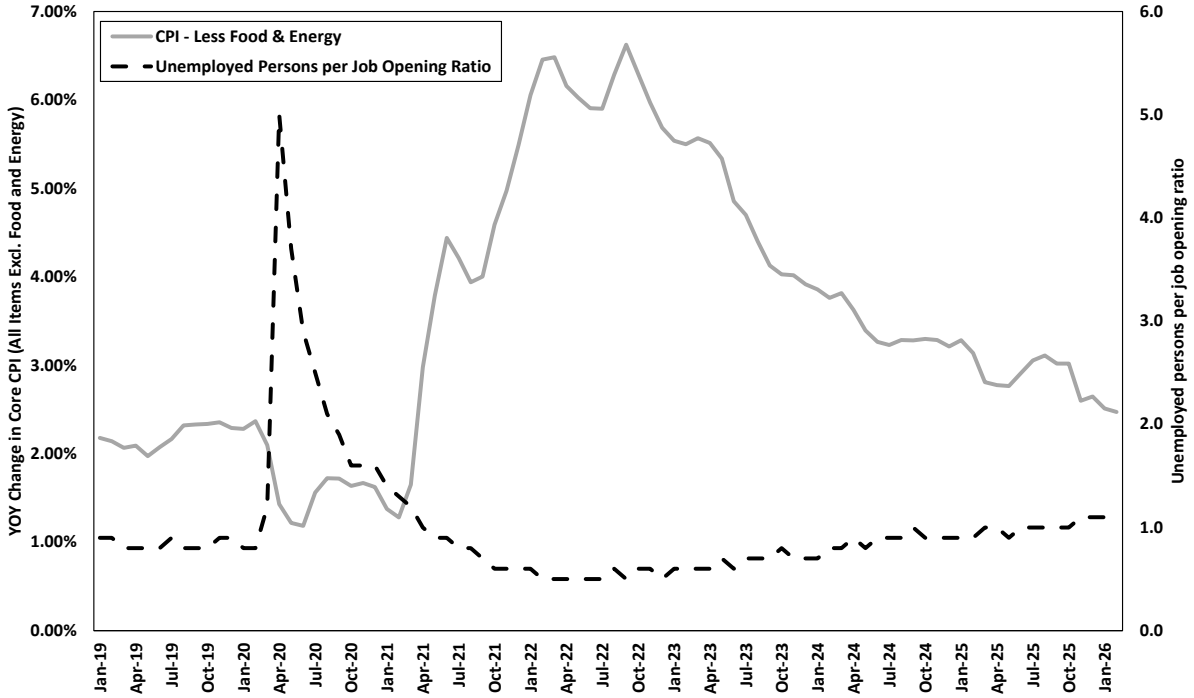
was the largest 12-month increase since 1982.[6] While core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain significantly above the Federal Reserve's target level of 2.0 percent.

Because the Federal Reserve's dual mandate is to promote stable prices and employment, it is important to consider employment data in addition to inflation. The ratio of unemployed persons per job opening was 1.1 in January 2026[7]. While the ratio of unemployed persons per job opening increased slightly in recent months, it had been consistently at or below 1.00 between April 2021 and October 2025, which suggested a tighter labor market. The strength in the labor market allowed the Federal Reserve to prioritize reducing inflation by pursuing the restrictive monetary policy needed to achieve its 2.00 percent target benchmark.

[6] Figure 2 presents the year-over-year (YOY) change in core inflation, as measured by the Consumer Price Index (CPI) excluding food and energy prices as published by the Bureau of Labor Statistics. I considered core inflation because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve because it removes the effect of food and energy prices, which can be highly volatile.

[7] The most recent data available at the time of this testimony; also January 2026 noted as "preliminary."

Figure 3: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to February 2026[8]



Q. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A. The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Between the March 2022 Federal Open Market Committee (FOMC) meeting and the July 2023 FOMC meeting, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00 – 0.25 percent to a range of 5.25 percent to 5.50 percent.

[8] Bureau of Labor Statistics.

Q. How did yields on long-term government bonds respond to the Federal Reserve's normalization of monetary policy?

A. Since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds has increased by over 350 basis points, increasing from 1.47 percent on December 15, 2021, to a peak of 4.98 percent on October 19, 2023. It currently remains well above 2021 levels (i.e., 4.21 percent) as of March 11, 2026.[9]

Q. Has the Federal Reserve reduced the federal funds rate?

A. Yes. The Federal Reserve reduced the federal funds rate by 50 basis points in September 2024, by 25 basis points in November and December 2024, and most recently by 25 basis points in September, October, and December 2025. While the Federal Reserve kept rates unchanged through the first five meetings in 2025, its decision to reduce the federal funds rate at the final three meetings in 2025 was due to an increase in the downside risk to employment in recent months.[10]

Q. What is the expected path of monetary policy over the near-term?

A. At the January 2026 FOMC meeting, Chairman Powell noted that inflation remains "somewhat elevated" and that "while job gains have remain low, the unemployment rate has shown signs of stabilization."[11] As a result, the FOMC decided to maintain the federal funds rate range of 3.50 percent to 3.75 percent.[12] In March 2026, the FOMC indicated that "economic activity has been expanding at a solid pace" but also noted that

[9] Bloomberg Professional.
[10] Federal Reserve, "Federal Reserve issues FOMC statement," Press Release, September 17, 2025, October 29, 2025, and December 10, 2025.
[11] Federal Reserve, "Transcript of Jerome Powell's Press Conference," January 28, 2026.
[12] *Id*.

uncertainty about the economic outlook for the U.S. economy, referencing the implications of developments in the Middle East.[13]

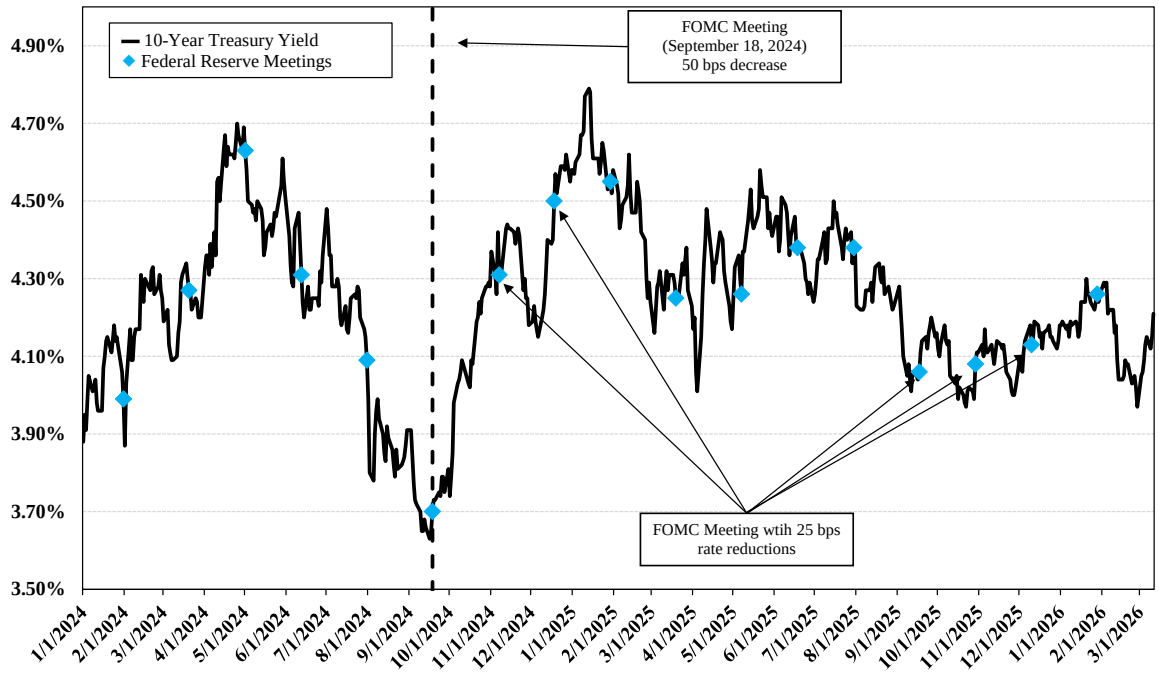
Regarding the possible path of monetary policy, Chairman Powell indicated that the reductions since September have brought the federal funds rate "within a range of plausible estimates of [the] neutral" rate and therefore, the Federal Reserve is well positioned to rely on incoming economic data to determine the extent and timing of any additional changes in the federal funds rates.[14] The FOMC published a forecast of the federal funds rate at the March 2026 meeting that was unchanged from December 2025 projections of one rate cut in December 2026.[15]

Q. What has happened to the yields on long-term government bonds since the FOMC first began to reduce the federal funds rate in September 2024?

A. As shown in Figure 4 below, while the yield on the 10-year treasury bond declined prior to the time of the first federal funds rate cut, the yield has generally increased since the September 2024 FOMC meeting. Further, while the yield on the 10-year Treasury bond has been volatile recently, it was 4.21 percent as of March 11, 2026, which is generally consistent with levels seen in July 2024, two months prior to the first reduction in the federal funds rate.

[13] Federal Reserve, "Federal Reserve issues FOMC statement," Press Release, March 18, 2026.
[14] *Id*.
[15] Federal Reserve, "Transcript of Chair Powell's Press Conference", March 18, 2026.

Figure 4: 10-Year Treasury Bond Yield, January 2024 through March 11, 2026[16]



Q. Why have long-term interest rates remained above the levels since the Federal Reserve began to reduce the federal funds rate in September 2024?

A. Ongoing policies of the current administration's economic plans have resulted in higher deficits, and persistent inflation. For example, since January 2025, the administration announced several sets of tariffs on each of the U.S.'s trading partners.[17] The implemented tariffs are largely viewed as inflationary. Inflation affects bonds, in particular long-term government bonds, because it erodes the value of future bonds payments. Therefore, in an inflationary environment, investors will demand higher returns on bonds to compensate for the added risk of inflation thus bond prices decline and the yields on bonds increase. The longer the duration of the bond, the greater the effect of inflation which is why inflation risk is greater for long-term government bonds.

[16] S&P Capital IQ Pro.
[17] Jennifer Clarke, "What Are Tariffs, How Do They Work and Why Is Trump Using Them?" *BBC News*, August 27, 2025.

The significant tariff policy increases the risk that inflation will remain elevated, which is why the yields on long-term bonds have not decreased and in fact have increased since the Federal Reserve first reduced the federal funds rate in September 2024. Further, the use of tariffs strains the relationship with trading partners, which could result in a reduction in the foreign demand for long-term U.S. government bonds resulting in additional upward pressure on long-term government bond yields.[18]

Q. What effect does the recent Supreme Court ruling have on the tariffs implemented by the administration in 2025?

A. On February 20, 2026, the Supreme Court ruled that the tariffs implemented in 2025 under the International Emergency Economic Powers Act were illegal. However, the administration responded to the ruling by imposing a 15 percent tariff on all goods imported into the U.S. under Section 122 of the 1974 Trade Act,[19] which allows a President to implement global tariffs up to 15 percent for a period of five months after which the approval of Congress is needed for continuation of the tariffs. Therefore, the administration is still able to at least temporarily impose global tariffs, which, as noted, will continue to place upward pressure on prices.

Q. Have there been any other recent developments that may affect inflation and long-term government bond yields?

A. Yes. The war in Iran and the resulting increase in underlying oil prices will likely put upward pressure on inflation as increased oil prices not only increase gasoline prices for consumers, but also the prices of other products as well given that nearly all goods need

[18] Karishma Vanjani, "U.S. Treasury Bonds Sell Off as 30-Year Yield Rises Most Since 1982," *Barron's*, April 9, 2025.
[19] Dearbail Jordan, "Trump says he will increase his new global tariffs to 15%," *BBC*, February 22, 2026.

to be transported from the place of production. The likelihood of continued elevated inflation suggests interest rates will remain higher in the near term.

Q. What are expectations for the yields on long-term government bonds?

A. While the Federal Reserve is forecasting additional cuts to the federal funds rate in 2026 and 2027, economists are still expecting elevated long-term interest rates. In the most recently published report by *Blue Chip Financial Forecasts*, the consensus estimate of economists is that the 30-year treasury bond yield will remain relatively stable and decrease only slightly from 4.80 percent in Q2/2026 to 4.70 percent in Q2/2027.[20] Additionally, the consensus estimate over the longer-term (*i.e.*, 2027–2031) is 4.60 percent.[21] Further, *Reuters* published the results of a survey of 75 bond strategists which suggests that aggressive tax and spending reforms could add over $3 trillion to the debt over the next decade. Bond strategists expect long-term bond yields to remain elevated even with the expectation that the Fed will decrease the federal funds rate because of inflation and a "resilient" economy.[22] This is important because it means that long-term interest rates are expected to remain elevated during the period that the company's rates will be in effect.

Q. What are your conclusions regarding the effect of current market conditions on the cost of equity for PacifiCorp?

A. It is important to consider current and projected market conditions in setting the forward-looking ROE due to its effect on the estimated cost of equity. While the FOMC reduced the federal funds rate several times in late 2025, Chairman Powell has indicated that the

[20] *Blue Chip Financial Forecasts*, Vol. 45, No. 3, February 27, 2026, at 2.
[21] *Blue Chip Financial Forecasts*, Vol. 44, No. 12, December 1, 2025, at 14.
[22] Reuters, "Long Treasury yields to stay elevated as inflation, debt pressures blunt Fed easing: Reuters poll", October 14, 2025.

Federal Reserve will continue to rely on incoming data to determine future adjustments to the federal funds rate. Further, long-term interest rates remain elevated and are expected to continue to remain elevated due to inflationary policies such as tariffs and tax cuts. With long-term interest rates expected to remain relatively high, borrowing also remains relatively more expensive, and thus investors also demand a relatively high cost of capital, which means the cost of capital also remains relatively high.

VI. PROXY GROUP SELECTION

Q. Please provide a brief profile of PacifiCorp.

A. PacifiCorp is an indirect, wholly owned subsidiary of BHE, and provides electric utility service to approximately 2.1 million residential, commercial and industrial customers in California, Idaho, Oregon, Utah, Washington, and Wyoming.[23] As of December 31, 2024, the company provided electric service to approximately 630,000 residential, commercial, and industrial customers in Oregon, with approximately 13,991 gigawatt-hours in electric sales.[24] The company's electric operations in Oregon represented approximately 25 percent of PacifiCorp's electric sales in 2025.[25] PacifiCorp currently has an investment grade long-term rating of BBB-(Outlook: Positive) from S&P and Baa2 (Outlook: Stable) from Moody's.[26] The Oregon operations are not separately rated from PacifiCorp.

[23] PacifiCorp SEC Form 10-K, December 31, 2025 at 3.
[24] 2024 Oregon Utilities Statistics Book.
[25] PacifiCorp SEC Form 10-K, December 31, 2025 at 4.
[26] S&P Global Ratings, *Research Update: PacifiCorp Outlook Revised to Positive Following Oregon Court of Appeals Decision (Apr 20, 2026)*; Moody's Ratings, Credit Opinion, PacifiCorp, Update following outlook revision to negative, March 19, 2026. Note that Moody's just recently revised PacifiCorp's outlook to stable and affirmed the Baa2 rating ("Rating Action: Moody's Ratings revises PacifiCorp's outlook to stable, affirms ratings" issued April 29, 2026).

Q. Why have you used groups of proxy companies to estimate the cost of equity for PacifiCorp?

A. In this proceeding, the cost of equity is being estimated for an electric utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and because PacifiCorp's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to the company in certain fundamental business and financial respects to serve as its "proxy" for purposes of estimating the cost of equity.

Even if the company was a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to PacifiCorp, and thus provide a reasonable basis to estimate the appropriate cost of equity for PacifiCorp.

Q. How did you select the companies in your proxy group?

A. I began with the group of 36 companies that *Value Line* classifies as electric utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, because companies that do not cannot be analyzed using the DCF model;
- have investment grade long-term issuer ratings from S&P and/or Moody's;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- own regulated generation assets that are in rate base;
- derive more than 30 percent of their megawatt-hour sales from its owned generation facilities;

- derive more than 60 percent of their total operating income from regulated electric operations; and,

- were not parties to a merger or transformative transaction during the analytical periods relied on.

Q. What is the composition of your proxy group?

A. Applying these screening criteria results in a proxy group consisting of the companies shown in Figure 5 (as well as in Exhibit PAC/403).

Figure 5: Proxy Group

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
Dominion Resources, Inc.	D
DTE Energy Company	DTE
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
PPL Corporation	PPL
Southern Company	SO
Xcel Energy Inc.	XEL

VII. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of a regulated utility.

A. The rate of return for a regulated utility is the weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective proportion (*i.e.*, book values) in the utility's capital structure. The ROE is the cost rate applied to the equity capital in calculating the rate of return. While the costs of debt and preferred stock

can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required cost of equity determined?

A. The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q. What methods did you use to estimate the cost of equity for PacifiCorp in this proceeding?

A. I consider the results of the constant growth and multi-stage forms of the DCF model, the CAPM, the ECAPM, and a BYRP analysis. A reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

Q. Is it important to use more than one analytical approach?

A. Yes. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical

matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[27] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[28] recommend the CAPM, DCF, and BYRP approaches.

Q. Has the Commission recognized that it is important to consider the results of multiple ROE estimation models?

A. Yes. In previous cases, the Commission has 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. Specifically, in the company's 2021 general rate case, the Commission considered the results of the DCF, CAPM and Risk Premium approaches:

> The Commission has previously accepted CAPM as a "useful and reliable addition to the DCF results" for determining cost of equity in certain cases. While we have historically rejected the risk premium analysis as unconventional and because it had not been accepted by other regulatory agencies, we note that FERC now gives equal consideration to DCF, CAPM and risk premium results.[29]

Further, the Commission recognized that no one party's application of any model is correct or certain. In that proceeding, the Commission considered the range of results established using the DCF model, the CAPM and the risk premium models. Further, the Commission recognized that the effects of the pandemic caused additional uncertainty in

[27] Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies*, at 214 (3rd ed. 2000).
[28] Eugene Brigham and Louis Gapenski, *Financial Management: Theory and Practice*, at 341 (7th ed. 1994).
[29] In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision, Docket No. UE 374, Order No. 20-476 at 30.

the assumptions used in the models. In addition, the Commission recognized incremental risk associated with PacifiCorp's capital investment plan and further recognized the relationship between the ROE and equity ratio.[30]

A. DCF Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, D1…D∞ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the constant growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. What assumptions are required for the constant growth DCF model?

A. The constant growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To

[30] *Id*., at 30-31.

the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data did you use to calculate the dividend yield in your constant growth DCF model?

A. The dividend yield in my constant growth DCF model is based on the proxy group companies' current annual dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended February 28, 2026.

Q. Why do you use three averaging periods for stock prices?

A. In my constant growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the cost of equity is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long term.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its constant growth form, the DCF model (*i.e.*, Equation [2]) assumes a single long-term growth rate in perpetuity. In order to reduce the long-term growth rate to a single measure, one must assume that the dividend payout ratio remains constant and that earnings per share (EPS), dividends per share, and book value per share all grow at the same constant rate. However, over the long run, dividend growth can only be sustained by earnings growth, meaning earnings are the fundamental driver of a company's ability to pay dividends. Therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to accurately reflect investor perceptions of a company's growth prospects. Accordingly, I have incorporated a number of sources of long-term EPS growth rates into the constant growth DCF model.

Q. What sources of long-term growth rates did you rely on in your constant growth DCF model?

A. My constant growth DCF model incorporates three sources of long-term projected EPS growth rates: (1) *Zacks Investment Research* (*Zacks*); (2) *S&P Capital IQ* ; and (3) *Value Line*.

Q. Have you previously relied on projected EPS growth rates provided by Yahoo! Finance?

A. Yes, however, *Yahoo! Finance* no longer reports consensus projected 3- to 5-year EPS growth rates. As a result, I have replaced the *Yahoo! Finance* data with the consensus projected 3- to 5-year EPS growth rates reported by *S&P Capital IQ.*

Q. How do you calculate the range of results for the constant growth DCF models?

A. I calculate the low-end result for the constant growth DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the *Zacks*, *S&P Capital IQ*, and *Value Line* projected EPS growth rates) for each of the proxy group companies. I use a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculate results using the average EPS growth rate from all three sources for each proxy group company.

Q. What are the results of your constant growth DCF models?

A. Exhibit PAC/404 and Figure 6 summarize the results of the constant growth DCF models.

Figure 6: Constant Growth DCF Model – Cost of Equity Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.36%	10.63%	11.66%
90-Day Avg. Stock Price	9.47%	10.74%	11.77%
180-Day Avg. Stock Price	9.56%	10.83%	11.86%
Average	9.46%	10.73%	11.76%
Median Results:			
30-Day Avg. Stock Price	9.68%	10.53%	11.34%
90-Day Avg. Stock Price	9.78%	10.63%	11.46%
180-Day Avg. Stock Price	9.84%	10.72%	11.61%
Average	9.77%	10.62%	11.47%

B. CAPM Analysis

Q. Please briefly describe the CAPM.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security.[31] This second component is the product of the market risk premium and the beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

K_e = the required market cost of equity;

β = the beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In this specification, the term $(r_m - r_f)$ represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the market as a whole. Beta is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

[31] Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

Variance (r_m) represents the variance of the market return, which is a measure of the uncertainty of the general market. *Covariance* (r_e, r_m) represents the covariance between the return on a specific security and the general market, which reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q. What risk-free rate did you use in your CAPM analysis?

A. I rely on three sources for my estimate of the risk-free rate (1) the current 30-day average yield on 30-year U.S. Treasury bonds, which is 4.79 percent;[32] (2) the average projected 30-year U.S. Treasury bond yield for the second quarter of 2026 through the second quarter of 2027, which is 4.76 percent;[33] and (3) the average projected 30-year U.S. Treasury bond yield for 2027 through 2031, which is 4.60 percent.[34]

Q. What beta coefficients do you use in your CAPM analysis?

A. As shown in PAC/405, I use the beta coefficients for the proxy group companies as reported by *Value Line*, which are based on five years of weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown on PAC/405 and PAC/406, I consider another CAPM analysis that relies on the long-term average utility beta coefficient for the companies in my proxy group, which is calculated as an average of the *Value Line* beta coefficients for the companies in my proxy group from 2013 through 2025.

[32] Bloomberg Professional.
[33] *Blue Chip Financial Forecasts*, Vol. 45, No. 3, at 2 (Feb 27, 2026).
[34] *Blue Chip Financial Forecasts*, Vol. 44, No. 12, at 14 (Dec. 1, 2025).

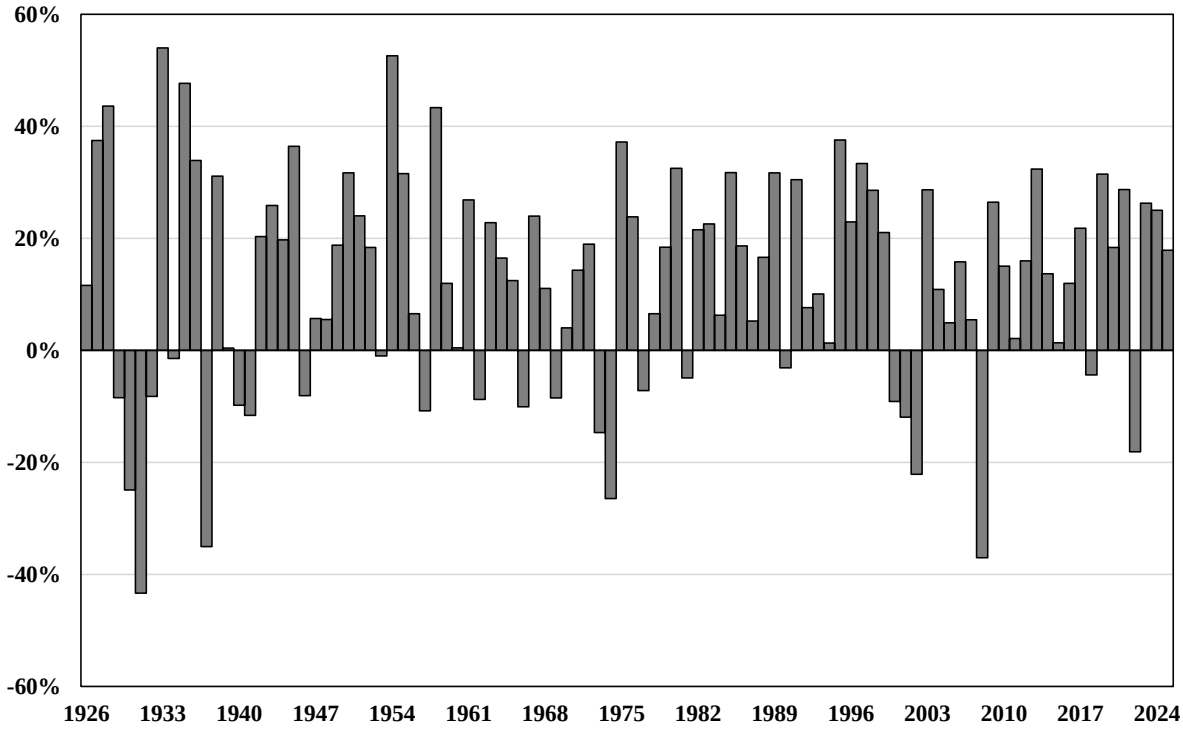
Q. How do you estimate the market risk premium in the CAPM?

A. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in PAC/407, the expected market return is calculated using the constant growth DCF model discussed previously as applied to the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.27 percent and a weighted long-term growth rate of 11.65 percent, the estimated required market return for the S&P 500 Index as of February 28, 2026 is 12.99 percent.

Q. How does the expected market return compare to observed historical market returns?

A. As show in Figure 7, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.99 percent is not unreasonable. In 53 out of the past 100 years (or 53 percent of observations), the realized equity market return was at least 12.99 percent or greater.

Figure 7: Realized U.S. equity market returns (1926–2025)[35]



Q. Did you consider another form of the CAPM in your analysis?

A. Yes. I have also considered the results of an ECAPM in estimating the cost of equity for PacifiCorp.[36] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

k_e = the required market cost of equity

[35] Depicts total annual returns on large company stocks, as reported in the 2023 Kroll SBBI Yearbook for 1926-2022 and from S&P Capital IQ Pro for 2023-2025.

[36] *See, e.g.*, Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., at 189 (June 1, 2006).

β = Adjusted Beta coefficient of an individual security
r_f = the risk-free rate of return
r_m = the required return on the market as a whole

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM; rather, it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, meaning that the CAPM underestimates the cost of equity for companies with a beta less than 1.0 and overestimates the cost of equity for companies with a beta greater than 1.0.[37]

Consistent with the CAPM, my application of the ECAPM uses the same three yields on the 30-year Treasury bond as the risk-free rate, forward-looking market return, and beta coefficients.

Q. What are the results of your CAPM and ECAPM analyses?

A. The results of my CAPM and ECAPM analyses are summarized in Figure 8, as well as presented in Exhibit PAC/405.

[37] *Id*., at 191.

Figure 8: CAPM and ECAPM – Cost of Equity Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.02%	11.01%	10.97%
Long-term Avg. *Value Line* Beta	11.04%	11.03%	11.00%
ECAPM:			
Current *Value Line* Beta	11.51%	11.51%	11.48%
Long-term Avg. *Value Line* Beta	11.53%	11.52%	11.49%

C. BYRP Analysis

Q. Please describe the BYRP approach.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for vertically integrated electric utilities as the historical measure of the cost of equity to determine the risk premium.

Q. What is the fundamental relationship between the equity risk premium and interest rates?

A. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice

versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. The analysis presented in Exhibit PAC/408 establishes that relationship using a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs serve as the measure of required equity returns and the long-term Treasury bond yield is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[38]

Q. What did your BYRP analysis reveal?

A. As shown in Figure 9, from 1980 through November 2023, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I have conducted a regression analysis using the following equation:

$$RP = a + b(T) \qquad [6]$$

Where:

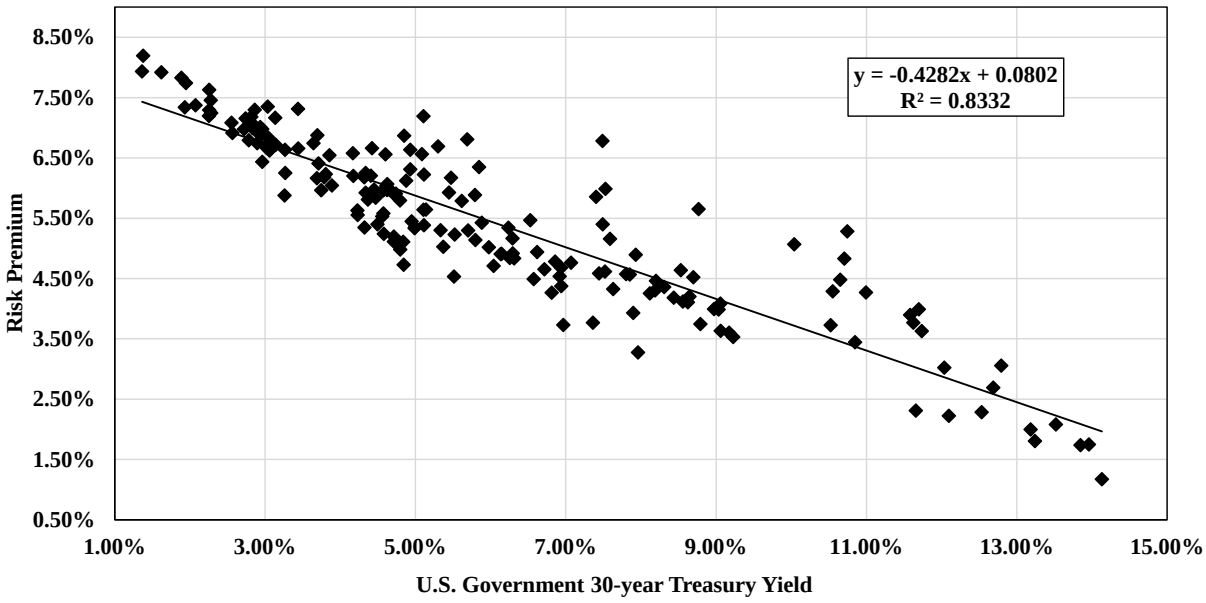
RP = Risk Premium (difference between authorized ROEs and the yield on 30-year Treasury bonds)
a = intercept term
b = slope term
T = 30-year Treasury bond yield

Data regarding authorized ROEs were derived from all of the vertically-integrated electric utility rate cases over this period as reported by Regulatory Research Associates (RRA).[39] The coefficients of the equation are statistically significant at the 99.00 percent level.

[38] *See e.g.*, S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (Mar. 1998) (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). *See also* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management, at 66 (Spring 1986).

[39] The data was screened to eliminate limited issue rider cases, electric transmission cases, electric distribution-only (*i.e.*, no generation) cases, and cases that were silent with respect to the authorized ROE.

Figure 9: Risk Premium Results



Q. What are the results of your BYRP analysis?

A. Figure 10 presents the results of my BYRP analysis, which is also presented in more detail in Exhibit PAC/408.

Figure 10: BYRP Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
Bond Yield Risk Premium	10.76%	10.74%	10.65%

D. Multi-Stage DCF Model

Q. Why are you presenting a multi-stage DCF model?

A. The Commission has indicated that it prefers the results of the multi-stage DCF model. For example, in its order in PacifiCorp's 2025 general rate case, the Commission stated:

> We have discussed the different types of models and the value we derive from looking at multiple models in determining the cost of equity, and have

primarily relied upon the multi-stage DCF model in determining a reasonable range of ROE.[40]

While I agree that the multi-stage DCF model is one of the methods considered by investors and regulators, I also agree with the Commission that it is reasonable to consider the results of other models to confirm the reasonableness of the results of that model.

Q. How does the multi-stage form of the DCF model differ from the constant growth form of the DCF model?

A. As with the constant growth DCF model, the multi-stage form of the model defines the cost of equity as the discount rate that sets the current price equal to the discounted value of future cash flows. However, the multi-stage DCF model, which is an extension of the constant growth form of the DCF, enables the analyst to specify different growth rates over multiple stages. The multi-stage DCF model allows for a gradual transition from the first-stage growth rate to the long-term growth rate, thereby avoiding the unrealistic assumption that growth changes abruptly between the first and final stages.

Q. What is the structure of the multi-stage DCF model?

A. The multi-stage DCF model sets a company's current stock price equal to the present value of future cash flows received over three "stages." In all three stages, cash flows are equal to the annual dividend payments that stockholders receive. Stage One is a short-term growth period that consists of the first ten years; Stage Two is a transition period from the short-term growth period to the long-term growth period, from years 11 through 20; and Stage Three is a long-term growth period that begins in year 21 and continues in

[40] In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision, Docket No. UE 433, Order No. 24-447 at 11.

perpetuity (*i.e.*, years 21 through 200). The cost of equity is then calculated as the rate of return that results from the initial stock investment and the dividend payments over the analytical period.

Q. Why is it reasonable for the first stage to be 10 years?

A. It is clear the utility industry is in a robust capital investment cycle that is expected to last for some time. It is unreasonable to suggest that the growth in the industry would begin to trend to a gross domestic product (GDP) growth rate in five years given the capital investment that is planned across the industry. Therefore, reverting to a GDP growth rate in a later year is more appropriate if one believes there is a need to use a multi-stage DCF model.

Q. What prices do you use in the mutli-stage DCF model?

A. I have relied on 30-day, 90-day and 180-day average stock prices for the proxy group companies, consistent with the averaging periods used for the constant growth DCF model.

Q. What growth rates did you rely on in the multi-stage DCF model?

A. As shown in Exhibit PAC/409, I began with the current annualized dividend as of February 28, 2026 for each proxy group company. In the first stage of the model, the current annualized dividend is escalated based on the average of the three-to five-year projected EPS growth rate estimates reported by *S&P Capital IQ, Zacks,* and *Value Line* that I rely on in the constant growth DCF. For the third stage of the model, I rely on long-term projected growth in GDP. The second stage growth rate is a transition from the first stage growth rate to the long-term growth rate on a geometric average basis.

Q. How did you calculate the long-term GDP growth rate?

A. As shown in Exhibit PAC/410, the projected long-term growth rate is 5.48 percent, which is based on real GDP growth rate of 3.17 percent from 1929 through 2025,[41] plus a projected inflation rate of 2.24 percent. The projected inflation rate is based on three measures: (1) the average long-term projected growth rate in the CPI of 2.30 percent;[42] (2) the compound annual growth rate of the CPI for all urban consumers for 2035-2050 of 2.23 percent as projected by the Energy Information Administration (EIA);[43] and (3) the compound annual growth rate of the GDP chain-type price index for 2035-2050 of 2.18 percent, also reported by the EIA.[44]

Q. What are the results of your multi-stage DCF models?

A. Figure 11 summarizes the results of the multi-stage DCF model.

Figure 11: Multi-Stage DCF – Cost of Equity Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.21%	9.70%	10.17%
90-Day Avg. Stock Price	9.33%	9.83%	10.31%
180-Day Avg. Stock Price	9.42%	9.94%	10.43%
Average	9.32%	9.83%	10.30%
Median Results:			
30-Day Avg. Stock Price	9.16%	9.50%	9.94%
90-Day Avg. Stock Price	9.27%	9.62%	10.03%
180-Day Avg. Stock Price	9.43%	9.78%	10.12%
Average	9.29%	9.63%	10.03%

[41] U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts Tables, Table 1.1.1 (Feb 28, 2025).
[42] *Blue Chip Financial Forecasts*, Vol. 44, No. 12 at 14 (December 1, 2025).
[43] U.S. Energy Information Administration, Annual Energy Outlook 2025, Table 20, Macroeconomic Indicators April 15, 2025).
[44] *Id*.

VIII. REGULATORY AND BUSINESS RISKS

Q. Do the results of the cost of equity analyses alone provide an appropriate estimate of the cost of equity for PacifiCorp?

A. No. These results provide only a range of the appropriate estimate of the company's cost of equity. Several additional factors must be considered when determining where the company's cost of equity falls within the range of analytical results. These risk factors, discussed below, should be considered with respect to their overall effect on the company's risk profile relative to the proxy group.

A. Wildfire Risk

Q. What have credit rating agencies and equity analysts stated regarding wildfire risk to the electric utility sector?

A. Credit rating agencies and equity analysts acknowledge the increasing threat of wildfire damage caused by and/or suffered by utility infrastructure as a substantial risk to utility investors. For example, S&P has recently stated:

> S&P Global Ratings continues to factor into its ratings on U.S. electric utilities the risk of liabilities from the utilities' contributing both to the ignition of wildfires as well as to related infrastructure damage. These risks have driven numerous rating changes and/or outlook revisions over the past several years, even considering some regulatory support for investor-owned utilities (IOUs) in California. S&P Global Ratings believes these risks will continue to increase due to ongoing droughts in certain regions (in part, due to climate change) that raise the susceptibility to a wildfire when high winds and an ignition source are added to the mix.[45]

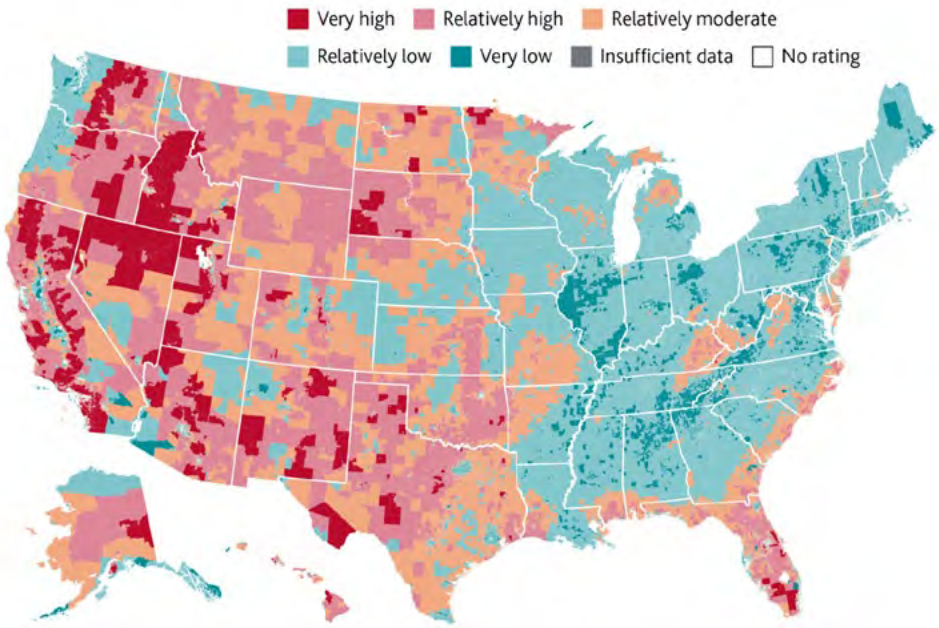
Q. Where is wildfire risk for utilities most prevalent?

A. The Federal Emergency Management Agency (FEMA) publishes a National Risk Index that ranks the wildfire risk by county and census tract in five categories: Very High,

[45] S&P Global Ratings, "After The Firestorms: Credit Risks Related to U.S. Wildfires," May 5, 2025, at 1.

Relatively High, Relatively Moderate, Relatively Low, and Very low. As shown in Figure 12, based on FEMA's assessment, wildfire risk is much broader than a few states, with the risk identified primarily as west of the Mississippi River, Hawaii, Florida, and along the eastern coast of the U.S.[46] The FEMA National Risk Index is one of the primary sources relied on by S&P in its assessment of wildfire risk for utilities.[47]

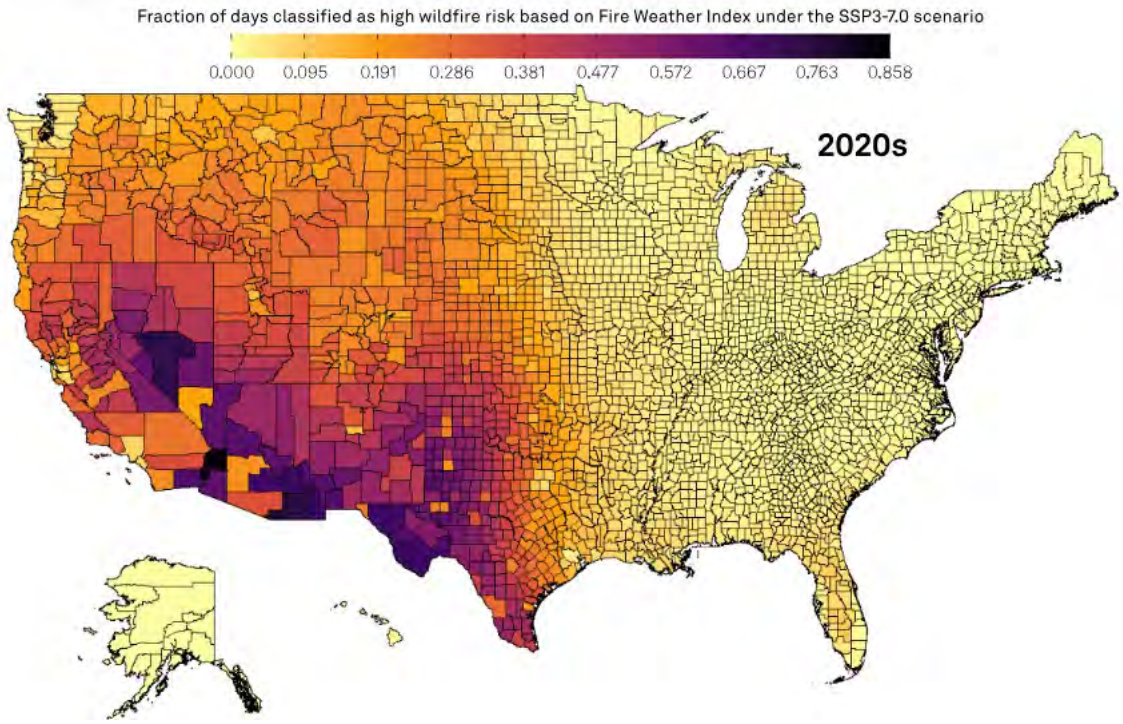
Figure 12: FEMA National Risk Index – Wildfire Risk by Census Tract[48]



Similarly, as shown in Figure 13, S&P Global Sustainable 1, which quantifies climate hazard exposures for U.S. local governments and their general obligation bonds (and is separate from S&P Global Ratings), also identifies the western United States as having the highest probability of wildfire risk.

46 FEMA National Risk Index; https://hazards.fema.gov/nri/map# (wildfire risk by census tract).
47 S&P Global Ratings, "After The Firestorms: Credit Risks Related to U.S. Wildfires," May 5, 2025, at 1.
48 Moody's Ratings, "Use of public safety power shutoffs to rise as utilities seek to reduce wildfire credit risk," June 4, 2024 (as obtained from FEMA National Risk Index; https://hazards.fema.gov/nri/map# (wildfire risk by census tract)).

Figure 13: S&P Global Sustainable1 – Wildfire Risk by Census Tract[49]



Q. What have the rating agencies stated specifically about wildfire risk for PacifiCorp?

A. As noted previously, the credit rating agencies have commented on the significant financial risk associated with wildfires for PacifiCorp and the effect of the court decisions on the company's credit outlook. S&P specifically noted that the company faces the threat of downgrade in the event of any future involvement in wildfire-related damages.[50]

Q. How has the increased risk of wildfires impacted utilities' insurance coverage?

A. Insurance coverage for utilities related to wildfires has become increasingly difficult to obtain, and even if coverage is able to be obtained, coverage has decreased and premiums have increased. For example, as noted recently by Morningstar DBRS:

> In what used to be considered a stable, low-risk industry, there has been a growing concern that wildfire-related losses, liabilities, and mitigation costs

[49] Therese Feng, Kuntal Singh, and Stacy Maher, "Quantifying the climate physical risk facing US muni bonds," S&P Global Sustainable1, April 25, 2024.

[50] S&P Global Ratings, Ratings Direct, Research Update: "*PacifiCorp Ratings Removed from CreditWatch Negative, Outlook Negative*", March 13, 2026, at 2.

> could strain a utility's finances and weaken its credit profiles. Utilities located in areas with heightened exposure to wildfire or with a history of lack of regulatory support to recover costs associated with wildfires could see a negative impact on their overall credit profile. A weaker credit profile in turn makes it more expensive for utilities to borrow money for critical investments. Compounding the problem, insurance costs for utilities with exposure to wildfire risk have increased materially (if insurance is even available), as private insurers are now retreating from wildfire-exposed markets. Overall, the sector faces a challenging financial environment: higher risk premiums, warier investors, and regulators under pressure to balance safety with affordable rates. The stakes are high: utilities are critical infrastructure, and their resilience in the face of wildfires is vital for the economy and public safety.[51]

While increased wildfire insurance premiums may be recoverable through rates, decreased coverage can expose shareholders to increased liability in the event of a wildfire. Further, even with insurance coverage, S&P highlights the risk that wildfire liabilities pose to investors:

> Given the increasing destructiveness of wildfires, especially in California, liability claims even from a single wildfire could exceed insurance coverage and balance sheet liquidity; therefore, a significant risk of exposure to these liabilities negatively weighs on credit quality. [52]

Q. Does PacifiCorp have a wildfire mitigation plan?

A. Yes. PacifiCorp's current wildfire mitigation plan, which was approved by the Commission on June 26, 2025,[53] presents programs that construct, maintain and operate the electric system in a manner that helps reduce the risk of ignition associated with PacifiCorp's assets, and to mitigate the spread of wildfire should ignition occur.

[51] Morningstar DBRS, "Line of Fire: How Wildfires Threaten Utility Credit," July 2, 2025, at 1-2.
[52] S&P Global Ratings, "After The Firestorms: Credit Risks Related to U.S. Wildfires," May 5, 2025, at 6-7.
[53] In the Matter of PacifiCorp, dba Pacific Power, Wildfire Protection Plan, Docket No. UM 2207, Order No. 25-233 (June 26, 2025).

Q. How does PacifiCorp recover its costs associated with wildfire mitigation?

A. Currently, PacifiCorp uses an annual tracking mechanism, known as the Automatic Adjustment Clause (AAC), for forecasted wildfire mitigation capital and operating expenses that was established via a settlement approved in 2023. An AAC filing is made annually with detailed invoice-level data on expenditures for review and approval. Balances for the capital and operating costs are recovered in the AAC until placed into base rates. The settlement is to be revisited by the Commission in May 2026 to assess whether the AAC allows parties an adequate opportunity to review the prudence of the wildfire mitigation expenditures, and whether it is appropriate to include performance metrics and/or earnings tests to incentivize PacifiCorp to optimize its wildfire mitigation spend over time.

Q. Does the existence of a wildfire mitigation plan eliminate all wildfire risk?

A. No. While having a wildfire mitigation plan reduces the probability of a wildfire ignition being associated with PacifiCorp's infrastructure, PacifiCorp nonetheless remains subject to wildfire risk.

For example, Southern California Edison Company (SCE) and Moody's recently collaborated on a forward-looking view of wildfire risk and the impact of its wildfire mitigation activities.[54] Using detailed data regarding the utility's infrastructure, Moody's estimated that SCE's wildfire mitigation measures had reduced the annual risk of a wildfire-related loss of greater than $1 billion from approximately 5.2 percent to 1.2 percent, and the risk that more than $3.5 billion would need to be withdrawn from the California Wildfire Fund over three years from approximately 2.9 percent to

[54] Moody's, "Wildfire risk: Quantifying the impact of mitigation measures in the power sector," 2024.

0.6 percent.[55] However, shortly after that study was published, the catastrophic Eaton fire in southern California in January 2025 caused S&P to revise its outlook from "stable" to "negative" for Edison International and its subsidiary SCE to reflect the possibility that the California Wildfire Fund, which had a balance of approximately $13 billion as of September 2025,[56] could be "materially" depleted as a result of the potential liability faced by SCE after the Eaton fire.[57] Therefore, while SCE's wildfire mitigation activities were estimated to have significantly decreased the probability of material financial liability from wildfires, that risk unfortunately nonetheless was realized shortly thereafter.

Q. What are your conclusions regarding the effect of wildfire risk on PacifiCorp in Oregon?

A. Wildfire risk presents one of the most significant business, operational, and financial threats for utilities in states subject to such risks. Oregon has significant wildfire risk, and it is clear that equity investors and credit rating agencies are reflecting the incremental risk for companies that have been affected by wildfire exposure and that the electric utility sector overall has increased risk related to this threat. The capital costs associated with wildfire mitigation can be significant and continue over many years, thus making the timeliness of cost recovery important. Addressing this risk in a timely manner should be a top regulatory priority in order to provide the company with the ability to access capital on reasonable terms, and make the capital investments needed going forward. Absent meaningful regulatory support, for PacifiCorp related to the recovery of wildfire

[55] *Id*.
[56] Eliyahu Kamisher and Michelle Ma, "California Plans to Boost Wildfire Fund By $18 Billion," Bloomberg, September 10, 2025.
[57] S&P Global Ratings, "Research Update: Edison International And Subsidiary SoCalEdison Outlooks Revised To Negative From Stable On Potential Risk For WildFire Fund Depletion: Ratings Affirmed," February 3, 2025.

mitigation costs, including insurance, the financial risks to the company increase significantly.

B. Capital Expenditures

Q. Please summarize PacifiCorp's capital expenditure requirements.

A. The company's current projection of capital expenditures for 2026 through 2030 totals approximately $13.1 billion[58], which represents approximately 47.5 percent of the company's approximate $27.6 billion in net utility plant as of December 31, 2024.[59]

Q. How do the company's capital expenditures compare to those of the proxy group?

A. As shown on Exhibit PAC/411, I have calculated the ratio of expected capital expenditures to net utility plant for the company and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2026 through 2030 by its total net utility plant as of December 31, 2024. As shown, the company's ratio of capital expenditures as a percentage of net utility plant is less than the median of the proxy group companies of 58.33 percent which all else equal indicates a risk level that is slightly lower than that of the companies in the proxy group.

Q. How is PacifiCorp's risk profile affected by its capital expenditure requirements?

A. As with any utility facing increased capital expenditure requirements, the company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

[58] Data provided by the Company.
[59] PacifiCorp 2024 FERC Form 1.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes. From a credit perspective, the additional pressure on cash flows associated with higher levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit- sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors. [60]

Recently, S&P evaluated the capital expenditure trends in the utility sector, noting that the balance between operating with negative discretionary cash flow from operations offset by reliable access to capital markets for financing may be tested through ever-increasing capital expenditure requirements as a result of the transformation of the energy sector through the focus on low/no carbon generation, electrification, and the replacement of aging infrastructure:

> Capital spending is exploding. The industry's capital spending over the past decade has been growing at a compound annual growth rate at about 6%. The industry's spending was mostly focused on safety, reliability, and

[60] S&P Global Ratings, Assessing U.S. Investor-Owned Utility Regulatory Environments, at 7 (Aug. 10, 2016).

> energy transition, successfully reducing its greenhouse gas emissions by about 27%.
>
> To accomplish its goals, the industry has transformed its generation, increasing its reliance on renewables (about 25% of total generation) and decreasing its reliance on coal fired generation (about 15% of total generation).
>
> However, because of data center growth, we expect IOU capital spending will grow at unprecedented levels during the next decade. To maintain credit quality over this timeframe, the industry must fund these projects in a credit-supportive manner. [61]

Therefore, to the extent that the company's rates do not continue to reasonably permit the recover its prudently incurred capital investments on a timely basis, the company would face increased recovery risk and thus increased pressure on its credit metrics.

Q. Does PacifiCorp have a capital tracking mechanism to recover the costs associated with capital expenditures between rate cases?

A. Partially. PacifiCorp is authorized to separately file to recover capital costs to construct or otherwise acquire renewable generation facilities and the associated transmission between rate cases through the Renewable Adjustment Clause. The company also has wildfire mitigation cost recovery through its Wildfire Mitigation Plan Automatic Adjustment Clause associated with its Wildfire Mitigation Plan. The company does not have cost recovery mechanisms for capital expenditures related to its transmission and distribution system unrelated to wildfire mitigation.

[61] S&P Global Ratings, Industry Credit Outlook 2026, North American Regulated Utilities: Data center growth will support credit quality in 2026, at 3-4 (January 14, 2026).

Q. What are your conclusions regarding the effect of the company's capital spending requirements on its risk profile and cost of capital?

A. The company's capital expenditure requirements as a percentage of net utility plant are significant and are expected to continue over the next few years. While the company does have capital cost recovery for certain renewable generation-related expenditures and wildfire-related expenditures, it does not for the recovery of its transmission and distribution expenditures unrelated to wildfire mitigation thus timely recovery of a substantial portion of the company's capital expenditures are not provided for between rate cases.

C. Regulatory Risks

Q. How does the regulatory environment affect investors' risk assessments?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms, and that doing so balances the long-term interests of investors and customers. Utilities must finance their operations and thus require the opportunity to earn a reasonable return on their invested capital to maintain their financial profiles. PacifiCorp is no exception, and in that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the

necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, a utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

Equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (*i.e.*, the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. Do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A. Yes. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[62]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "we assess regulatory advantage because the

[62] Moody's Investors Service, "Rating Methodology: Regulated Electric and Gas Utilities," August 6, 2024, at 2.

influence of the regulatory framework and regime is of critical importance. It defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[63] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[64]

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[u]tility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the regulatory framework is a key determinant of the credit quality of a utility."[65] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[t]he regulatory framework is important because it provides the basis for decisions that affect utilities, including rate-setting as well as the consistency and predictability of regulatory decision-making."[66]

[63] Standard & Poor's Global Ratings, "Sector-Specific Corporate Methodology," April 4, 2024, at 147.
[64] *Id*.
[65] Moody's Investors Service, "Rating Methodology: Regulated Electric and Gas Utilities," August 6, 2024, at 8.
[66] *Id*.

Q. Is the regulatory environment of particular concern to PacifiCorp currently?

A. Yes. While S&P recently changed PacifiCorp's outlook to positive, earlier this year it issued a Credit Watch negative outlook. Moody's outlook for PacifiCorp remains negative. At different times, both agencies have noted the potential for downgrades of the company's credit ratings in the next 12 -18 months under certain circumstances. While S&P revised its outlook on PacifiCorp to Positive following the Oregon Court of Appeals decision in the James wildfire lawsuit, there is still concern about the Company's liabilities in these proceedings and its Funds from Operations (FFO) to debt ratios. S&P noted that their ratings could be affirmed if the Court of Appeals' decision is not upheld or if the James Case proceedings continue on the current timeline. S&P suggested that several factors would be necessary for a future upgrade: 1) the Court's ruling is upheld, 2) the Company's wildfire liabilities are substantially reduced, 3) the Company's short-term liquidity requirements are drastically lowered, 4) the James Case proceedings are materially delayed, 5) the Company is not the cause of a materially significant wildfire and 6) the Company maintains an FFO to debt ratio that is consistently above 9 percent.[67]

Moody's indicated that PacifiCorp has elevated financial leverage, and in March 2026 revised the outlook for PacifiCorp to negative: "reflecting heightened uncertainty around future bond-posting requirements associated with the *James* wildfire litigation and the potential implications for lender confidence in a downside scenario."[68] Further, while Moody's expects that the company will have cash from operations pre-working capital to

[67] S&P Global Ratings, Ratings Direct, Research Update: "*PacifiCorp Outlook Revised to Positive Following Oregon Court of Appeals Decision"*, April 29, 2026, at 1- 2.

[68] Moody's Ratings, Credit Opinion, PacifiCorp, Update following outlook revision to negative, March 19, 2026.

debt metric in the range of 13%-16% over the next 12-18 months, if the metric were to fall below 13%, it would likely result in a downgrade.

Q. What do you conclude from the recent actions from the credit rating agencies?

A. The rating agencies are actively monitoring the financial metrics of the Company. PacifiCorp's credit rating remains BBB- from Standard & Poor's,. While the outlook is positive, it is contingent on the Company's ability to maintain its credit metrics among other factors. While it is important to maintain an FFO coverage ratio of 9 percent for S&P, that metric will only maintain the current BBB- rating with a positive outcome. Therefore, ongoing regulatory support is necessary to increase the Company's credit rating to be more consistent with its utility peers.

Q. Have you conducted any analysis of the regulatory framework in Oregon relative to the jurisdictions in which the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in Oregon based on five factors that are important in terms of providing a regulated utility an opportunity to earn its authorized ROE. These factors are: (1) fuel cost recovery; (2) the test year convention for ratemaking (*i.e.*, forecast vs. historical test year); (3) use of rate design and/or other mechanisms that mitigate volumetric risk and stabilize revenue; and (4) prevalence of capital cost recovery between rate cases. The results of my regulatory risk assessment are shown in Exhibit PAC/412 and are summarized below.

- Fuel Cost Recovery: PacifiCorp has a Power Cost Adjustment Mechanism (PCAM) to recover power costs. However, the PCAM is subject to sharing of variances in fuel and purchased power costs that vary between the forecast and actual level of these

costs.[69] Specifically, there is an asymmetric deadband (*i.e.*, -$15 million to +$30 million) within which the company is wholly responsible for the variances, and sharing also applies for any variances outside the deadband, with customers assuming 90 percent and the utility assuming 10 percent of the variance. The recovery of fuel and purchased power costs are also subject to an earnings test where (1) if the company's earnings are more than 100 basis points below its authorized ROE, it is allowed to recover excess power costs, after application of the deadband and 90/10 sharing, up to an earnings level that is 100 basis points less than its authorized ROE; or (2) if the company's earnings are more than 100 basis points above its authorized ROE, then it would be required to refund to customers any power cost savings, after application of the deadband and sharing, down to the ROE plus 100 basis points threshold. Lastly, amortization of deferred amounts under the PCAM in any one year are limited to 6 percent of company's revenues for the preceding calendar year.

As a result, the PCAM does not fully mitigate the company's risk of recovery of its fuel and purchased power costs, which is important to investors given that fuel and purchased power costs typically account for 50 - 60 percent of the total operating costs for a regulated utility. Moreover, there are only 9 states (*i.e.*, Hawaii, Idaho, Missouri, Montana, Oregon, Vermont, Washington, Wisconsin, and Wyoming) that have fuel cost recovery mechanisms with sharing bands. The remaining states either have restructured and the electric utilities do not own generation or have fuel cost recovery mechanisms with a true-up between actual and forecasted fuel costs. In addition, approximately 90 percent of the operating companies held by the proxy

[69] Docket No. UE 246, Order No. 12-493 at 14-15 (Dec. 20, 2012).

group are allowed to pass through fuel costs and purchased power costs directly to customers, without deadbands, sharing bands and earnings tests.

- *Test Year Convention:* The company relies on a forecasted test year for ratemaking purposes. Forecast test years result in more prompt recovery of incurred costs and thus mitigates the regulatory lag associated with historical test years. As Lowry, Hovde, Getachew, and Makos (2010) explain:

> This report provides an in depth discussion of the test year issue. It includes the results of empirical research which explores why the unit costs of electric IOUs are rising and shows that utilities operating under forward test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years. *The research suggests that shifting to a future test year is a prime strategy for rebuilding utility credit ratings as insurance against an uncertain future*.[70]

As shown in Exhibit PAC/412, approximately 53 percent of the operating utility subsidiaries of the proxy group companies provide service in jurisdictions that use a forecasted test year.

- *Revenue Stabilization/Non-Volumetric Rate Design*: The company does not have protection against volumetric risk in Oregon. In contrast, as shown in Exhibit PAC/412, approximately 65 percent of the utility operating subsidiaries of the proxy group companies have some form of revenue stabilization through either decoupling, formula-based rates, and/or straight-fixed variable rate design that allow them to break the link between customer usage and revenues.

- *Capital Cost Recovery*: As discussed, the company has capital cost recovery mechanisms for the construction of new renewable generation and associated

[70] Mark Newton Lowry, David Hovde, Lullit Getachew, and Matt Makos. *Forward Test Years for US Electric Utilities*," at 1, (Prepared for the Edison Electric Institute, Aug. 2010); emphasis added.

transmission, as well as wildfire mitigation expenditures. Similarly, as shown in Exhibit PAC/412, approximately 80 percent of the operating utility subsidiaries of the proxy group companies also have some form of capital cost recovery allowing for the recovery of capital investments placed into service between rate cases.

Q. Have you conducted any additional analyses to evaluate the regulatory environment in Oregon as compared to the jurisdictions in which the companies in the proxy group operate?

A. Yes, I have conducted two additional analyses to compare the regulatory framework of Oregon to the jurisdictions in which the companies in the proxy group operate. Specifically, I considered two different rankings: (1) the RRA ranking of regulatory jurisdictions; and (2) S&P's ranking of the credit supportiveness of regulatory jurisdictions.

Q. How does RRA evaluate the regulatory environment in each jurisdiction?

A. RRA evaluates the regulatory environment from an investor perspective, considering the relative regulatory risk associated with ownership of securities issued by the companies that are regulated in each jurisdiction. RRA considers several factors that affect the regulatory process including gubernatorial, legislative and court activity, rate case decisions and other regulatory decisions, and information obtained through contact with commissioners, staff, utilities, and government outreach.

Q. How do you use the RRA ratings to compare the regulatory jurisdictions of the proxy group companies with the company's regulatory jurisdiction?

A. RRA assigns a ranking for each regulatory jurisdiction as "Above Average", "Average" or "Below Average", and then within each of those categories, a numeric ranking from

1 to 3. Thus, there are a total of nine RRA rankings, with the rankings for each jurisdiction ranging from "Above Average/1", which is considered the most supportive, to "Below Average/3," which is the least supportive. I have applied a numeric ranking system to the RRA rankings with "Above Average/1" assigned the highest ranking (*i.e.*, a "1") and "Below Average/3" assigned the lowest ranking (*i.e.*, a "9").

As shown on Exhibit PAC/413, the Oregon jurisdictional ranking is "Average / 3" (*i.e.*, a "6"), which is below the proxy group average ranking of between "Average/1" and "Average/2" (*i.e.*, a "4.73").

Q. How do you conduct your analysis of the S&P credit supportiveness ranking?

A. For credit supportiveness, S&P classifies each regulatory jurisdiction into five categories that range from "Most Credit Supportive" down to "Credit Supportive." My analysis of the credit supportiveness of the regulatory jurisdictions in which the proxy companies operate as compared to the company's regulatory jurisdiction is similar to the analysis of the RRA overall regulatory ranking discussed above. Specifically, I have assigned a numerical ranking to each category, from Most Credit Supportive (*i.e.*, a "1") to Credit Supportive (*i.e.*, a "5").

As shown on Exhibit PAC/414, similar to the RRA regulatory rankings discussed above, S&P ranks Oregon as "4", which is below the proxy group average ranking of "2.39".

Q. Is it important that the Commission consider how the ROE to be authorized for the company in this proceeding compares to other comparable utilities?

A. Yes. As discussed previously, the credit rating agencies have changed the outlook for PacifiCorp multiple times this year and have indicated that negative regulatory, and

legislative actions could further affect the company's credit ratings, resulting in credit rating downgrades of one or more notches. Further, while the company is currently operating within the ranges established by S&P and Moody's for key credit metrics (FFO for S&P and cash from operations pre-working capital to debt for Moody's), it is important that the company maintain these coverage ratios to avoid further decay in credit metrics. Currently PacifiCorp is rated BBB- with a positive outlook from S&P, which is the lowest investment grade rating. Moody's rates PacifiCorp Baa2 with a negative outlook which is only one notch above the lowest investment grade rating from Moody's. Therefore, the ROE and equity ratio that the Commission authorizes in this proceeding will be important to ensure the financial stability of PacifiCorp and to provide access to capital on reasonable terms for the benefit of customers.

IX. CAPITAL STRUCTURE

Q. Is the capital structure of the company an important consideration in the determination of the appropriate ROE?

A. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility. All else equal, a higher debt ratio increases the risk to investors, which has been recognized by the Commission.[71] Specifically, for debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, whose claim on the cash flow of the company is secondary to debt

[71] See, e.g., In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision, Docket No. UE 374, Order No. 20-476 at 31 (fn 135) (Dec. 18, 2020).

holders. Therefore, the greater the debt service requirement, the less cash flow is available for common equity holders.

Q. What is PacifiCorp's proposed capital structure?

A. As discussed more thoroughly by company witness Weems, PacifiCorp is proposing a capital structure that is composed of 50.00 percent common equity and 50.00 percent long-term debt.

Q. Does the company's proposed capital structure differ from its actual capital structure?

A. Yes. The company's actual capital structure has been affected by recent significant one-time events that resulted in a more highly leveraged capital structure than is typically relied upon to finance the business. In the company's last rate proceeding, the equity ratio that was agreed to by the parties was composed of 50 percent equity and 50 percent long-term debt, which is consistent with the proposed equity ratio in this proceeding.

Q. Did you conduct any analysis to determine if the requested equity ratio was reasonable?

A. Yes. I compared PacifiCorp's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. The cost of equity is estimated based on the return that is derived from companies in the proxy group that are deemed to be comparable in risk to the company; however, those companies must be publicly traded in order to apply the cost of equity models. The operating utility subsidiaries of the proxy group companies are most risk-comparable to the company, and thus it is reasonable to look to the average capital structure of the operating utilities of the proxy group to benchmark the equity ratios for the company.

Specifically, I have calculated the average proportion of common equity, long-term debt, and preferred equity for the most recent three years for each of the utility operating subsidiaries of the proxy group companies. As shown in Exhibit PAC/415, the mean and median equity ratios for the utility operating subsidiaries of the proxy group are 52.93 percent and 52.64 percent respectively, which are significantly higher than the company's proposed equity ratio percent.

Q. Are there other factors to be considered in setting the company's capital structure?

A. Yes, there are other factors that should be considered in setting the company's capital structure, namely the challenges that the credit rating agencies have highlighted as placing pressure on the credit metrics for utilities generally and PacifiCorp specifically. In addition to the concerns outlined above for PacifiCorp specifically, as it relates to the company's leverage, regulatory, legislative and wildfire risk, the credit rating agencies have outlined the need for constructive regulation to support the financial metrics of utilities in the current environment of higher capital investment.

For example, Moody's recently maintained its "stable" outlook for 2026 for the regulated gas and electric utilities sector based on the expectation of continued regulatory support in "most states." [72] Moody's makes clear that constructive regulatory outcomes that promote timely cost recovery is the key factor in supporting utility credit quality as Moody's has identified that utilities could be exposed to a number of credit negative factors over the next 12 to 18 months. Specifically, Moody's noted the following factors: (1) macroeconomic factors are expected to be modestly credit negative due to upward pressure on electric prices and elevated inflation; and (2) increased power demand due to

[72] Moody's Investors Service, Outlook, "Outlook Stable; supportive regulation to offset modestly negative macro factors," October 31, 2025.

"the development of new data centers, electrification of transportation and buildings, manufacturing customers and underlying population growth" will increase power prices which when coupled with inflation and elevated capital spending increases utilities' exposure to affordability concerns.[73]

S&P states that after five years of downgrades outpacing upgrades, in 2025, upgrades outpaced downgrades and the percentage of companies with a negative outlook declined which S&P noted pointed to a "more stable environment for credit quality in 2026".[74] However, S&P expects the industry to have increased cash flow deficits as a result of significant capital spending, which must be funded with both debt and equity to maintain credit quality.[75] Therefore, S&P notes that the utility industry will need ongoing access to capital markets to fund the significant capital expenditures. S&P also notes that credit quality will depend on the ability of utilities to manage regulatory risk and achieve fair rate case orders. Finally, while S&P's base case results in a stable outlook for the utility sector, S&P states that about 40 percent of the industry has "minimal financial cushion" from the downgrade threshold and therefore would have limited ability to absorb any unexpected events outside of what is assumed in S&P's base case.[76]

Fitch maintains a "neutral" outlook for the utility industry in 2026 noting that the stable outlook was supported by growth in sales related to data centers and a "generally benign" regulatory environment for utilities.[77] However, while Fitch views load growth as a "positive development" because the growth is related to data centers, it raises longer-

[73] *Id.*
[74] S&P Global Ratings. Industry Credit Outlook 2026, "North American Regulated Utilities: Data center growth will support credit quality in 2026," January 14, 2026.
[75] *Id.*
[76] *Id.*
[77] Fitch Ratings, "North American Utilities & Power Outlook 2026," December 9, 2025, at 1.

term uncertainty related to "rate design, customer concentration, and technology risks".[78] Further, Fitch states that capital expenditures for the industry will continue to "set records" in order to meet the growing demand and to enhance reliability and modernize. The record capital expenditures will require a balanced regulatory environment to facilitate cost recovery in a credit supportive manner.[79]

The continued concerns of the credit ratings agencies over increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for the company in the context of this proceeding.

X. CONCLUSIONS

Q. What is your conclusion regarding a fair ROE for the Company?

A. Figure 14 summarizes the results of my cost of equity analyses. Considering these results and the qualitative analyses presented in my direct testimony, and the company's regulatory, business, and financial risk relative to the proxy group, I conclude that the company has greater risk than the proxy group companies and therefore an ROE towards the higher end of the range of results is reasonable. However, the return that PacifiCorp is requesting is 9.70 percent. While this is at the low end of my range of results and is therefore conservative, PacifiCorp is limiting its request in recognition of ongoing affordability concerns.

[78] *Id.*
[79] *Id.*

Figure 14: Summary of Cost of Equity Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.36%	10.63%	11.66%
90-Day Avg. Stock Price	9.47%	10.74%	11.77%
180-Day Avg. Stock Price	9.56%	10.83%	11.86%
Average	9.46%	10.73%	11.76%
Median Results:			
30-Day Avg. Stock Price	9.68%	10.53%	11.34%
90-Day Avg. Stock Price	9.78%	10.63%	11.46%
180-Day Avg. Stock Price	9.84%	10.72%	11.61%
Average	9.77%	10.62%	11.47%

Multi-Stage DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.21%	9.70%	10.17%
90-Day Avg. Stock Price	9.33%	9.83%	10.31%
180-Day Avg. Stock Price	9.42%	9.94%	10.43%
Average	9.32%	9.83%	10.30%
Median Results:			
30-Day Avg. Stock Price	9.16%	9.50%	9.94%
90-Day Avg. Stock Price	9.27%	9.62%	10.03%
180-Day Avg. Stock Price	9.43%	9.78%	10.12%
Average	9.29%	9.63%	10.03%

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	11.02%	11.01%	10.97%
Long-term Avg. *Value Line* Beta	11.04%	11.03%	11.00%
ECAPM:			
Current *Value Line* Beta	11.51%	11.51%	11.48%
Long-term Avg. *Value Line* Beta	11.53%	11.52%	11.49%
Bond Yield Risk Premium	10.76%	10.74%	10.65%

Q. What is your conclusion with respect to the company's proposed capital structure?

A. My conclusion is that the company's proposal to establish a capital structure consisting of 50.00 percent common equity and 50.00 percent long-term debt is necessary to increase its credit metrics to the ranges established by the credit rating agencies for the company's current credit ratings. Further, the proposed capitalization is conservative when compared to the proxy group companies, as the equity ratio proposed by the company is well below the mean or median equity ratio of the utility operating companies of the proxy group. Finally, maintaining the company's credit ratings and the ability to access capital on reasonable terms, particularly at a time when the company has significant capital requirements, provides benefits to customers over the long-term. Therefore, I conclude that the company's proposed capital structure is reasonable and should be approved.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 470
Exhibit PAC/401
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Resume and Testimony Listing of Ann E. Bulkley

May 2026

Ann E. Bulkley

PRINCIPAL

Boston 508.981.0866 Ann.Bulkley@brattle.com

With more than 30 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas and water utility sectors, including valuation of regulated and unregulated utility assets, cost of capital, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in more than 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies

- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff and prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

- Conducted a strategic review of the acquisition of nuclear generation assets. Review included the evaluation of the operating costs of the facilities and the long-term liabilities associated with the assets including the decommissioning of the assets.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Conducted a valuation of regulated utility assets for the fair value rate base estimate used in electric rate proceedings in Indiana.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

BULKLEY TESTIMONY LISTING

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Tucson Electric Power Company	6/25	Tucson Electric Power Company	Docket No. G-01933A-25-0103	Return on Equity
UNS Gas	11/24	UNS Gas	Docket No. G-04204A-24-0237	Return on Equity
Southwest Gas Corporation	02/24	Southwest Gas Corporation	Docket No. G-01551A-23-0341	Return on Equity
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Pacific Gas & Electric Company	03/25	Pacific Gas & Electric Company	25-03-010	Return on Equity
PacifiCorp, d/b/a Pacific Power	05/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity
Colorado Public Utilities Commission				
Public Service Company of Colorado	12/25	Public Service Company of Colorado	Docket No. 25AL-0499G	Return on Equity
Public Service Company of Colorado	11/25	Public Service Company of Colorado	Docket No. 25AL-0494E	Return on Equity
Public Service Company of Colorado	01/24	Public Service Company of Colorado	Docket No. 24AL-___G	Return on Equity
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
United Illuminating	11/24	United Illuminating	Docket No. 24-10-04	Return on Equity
The Southern Connecticut Gas Company	11/23	The Southern Connecticut Gas Company	Docket No. 23-11-02	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Connecticut Natural Gas Corporation	11/23	Connecticut Natural Gas Corporation	Docket No. 23-11-02	Return on Equity
Connecticut Water Company	10/23	Connecticut Water Company	Docket No. 23-08-32	Return on Equity
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Northern Natural Gas Company	07/25	Northern Natural Gas Company	Docket No. RP25-___	Return on Equity
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
Intermountain Gas Co	05/25	Intermountain Gas Co	C-INT-G-25-02	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/24	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-24-04	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-24-04	Return on Equity
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Peoples Gas Light & Coke Company	01/26	Peoples Gas Light & Coke Company	D-26-0065	Return on Equity
North Shore Gas Company	01/26	North Shore Gas Company	D-26-0066	Return on Equity
Illinois American Water	01/24	Illinois American Water	Docket No. 24-0097	Return on Equity
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indiana Utility Regulatory Commission				
Ohio Valley Gas Corporation and Ohio Valley Gas, Inc.	02/24	Ohio Valley Gas Corporation and Ohio Valley Gas, Inc.	Cause No. 46011	Return on Equity
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	12/23	Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	IURC Cause No. 45990	Return on Equity
Indiana Michigan Power Co.	08/23	Indiana Michigan Power Co.	IURC Cause No. 45933	Return on Equity
Indiana American Water Company	03/23	Indiana and Michigan American Water Company	IURC Cause No. 45870	Return on Equity
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
MidAmerican Energy Company	02/25	MidAmerican Energy Company	Docket No. RPU-2025-0001	Return on Equity
Iowa-American Water Company	04/24	Iowa-American Water Company	Docket No. RPU-2024-000_	Return on Equity
MidAmerican Energy Company	06/23	MidAmerican Energy Company	Docket No. RPU-2023-___	Return on Equity
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Evergy Kansas	01/25	Evergy Kansas	Docket No. 25-EKCE-294-RTS	Return on Equity
Evergy Kansas	04/23	Evergy Kansas	Docket No. 23-EKCE-775-RTS	Return on Equity
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				
Kentucky American Water Company	04/25	Kentucky American Water Company	Docket No. 2025-____	Return on Equity
Kentucky American Water Company	06/23	Kentucky American Water Company	Docket No. 2023-____	Return on Equity
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	09/25	Central Maine Power	Docket No. 2025-____	Return on Equity
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
Boston Gas Company	01/26	Boston Gas Company	DPU 26-50	Return on Equity
Berkshire Gas Company	11/25	Berkshire Gas Company	DPU 25-170	Return on Equity
Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	11/23	Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	DPU 23-150	Return on Equity
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Consumers Energy	6/25	Consumers Energy	C-U-21870	Return on Equity
Consumers Energy	12/24	Consumers Energy	C-U-21806	Return on Equity
Upper Michigan Energy Resources Corporation	05/24	Upper Michigan Energy Resources Corporation	Case No. U-21541	Return on Equity
Michigan Gas Utilities Corporation	03/24	Michigan Gas Utilities Corporation	Case No. U-21540	Return on Equity
Indiana Michigan Power Co.	09/23	Indiana Michigan Power Co.	Case No. U-21461	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Michigan Gas Utilities Corporation	03/23	Michigan Gas Utilities Corporation	Case No. U-21366	Return on Equity
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
Otter Tail Power Company	10/25	Otter Tail Power Company	E017/GR-25-359	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/23	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-23-155	Return on Equity
CenterPoint Energy Resources	11/23	CenterPoint Energy Resources	D-G-008/GR-23-173	Return on Equity
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Evergy Metro Inc.	02/26	Evergy Metro Inc.	C-ER-2026-0143	Return on Equity
Ameren Missouri	09/24	Ameren Missouri	File No. GR-2024-0369	Return on Equity
Missouri American Water Company	07/24	Missouri American Water Company	WR-2024-0320	Return on Equity
Ameren Missouri	06/24	Ameren Missouri	File No. ER-2024-0319	Return on Equity
Evergy Missouri West	02/24	Evergy Missouri West	File No. ER-2024-0189	Return on Equity
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	01/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	01/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	9/25	Montana-Dakota Utilities Co.	D2025-09-072	Return on Equity
Montana-Dakota Utilities Co.	7/24	Montana-Dakota Utilities Co.	D2024-05-061	Return on Equity
Montana-Dakota Utilities Co.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
Public Utilities Commission of Nevada				
Nevada Power Company d/b/a NV Energy	02/25	Nevada Power Company d/b/a NV Energy	25-02016	Return on Equity
Sierra Pacific Power Company d/b/a NV Energy	02/24	Sierra Pacific Power Company d/b/a NV Energy	24-02026	Return on Equity
Nevada Power Company d/b/a NV Energy	06/23	Nevada Power Company d/b/a NV Energy	23-06007	Return on Equity
Nevada Power Company d/b/a NV Energy	03/23	Nevada Power Company d/b/a NV Energy	22-03028	Merger benefits
New Hampshire - Board of Tax and Land Appeals				
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Liberty Utilities (EnergyNorth Natural Gas)	07/23	Liberty Utilities (EnergyNorth Natural Gas)	Docket No. DG 23-067	Return on Equity
Liberty Utilities (Granite State Electric)	05/23	Liberty Utilities (Granite State Electric)	Docket No. DE 23-039	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
South Jersey Gas Company	11/25	South Jersey Gas Company	D-GR25110627	Return on Equity
New Jersey American Water Company, Inc.	02/24	New Jersey American Water Company, Inc.	WR2401056	Return on Equity
Elizabethtown Gas Company	2/24	Elizabethtown Gas Company	GR24020158	Return on Equity
Public Service Electric and Gas Company	12/23	Public Service Electric and Gas Company	ER23120924 GR23120925	Return on Equity
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity
New Mexico Public Regulation Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
New York State Electric and Gas Company Rochester Gas and Electric	06/25	New York State Electric and Gas Company Rochester Gas and Electric	25-E-0375 25-G-0378 25-E-0379 25-G-0380	Return on Equity
Liberty Utilities (New York Water)	5/23	Liberty Utilities (New York Water)	Case 23-W-0235	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Otter Tail Power Company	11/23	Otter Tail Power Company	Case No. PU-23-342	Return on Equity
Montana-Dakota Utilities Co.	11/23	Montana-Dakota Utilities Co.	Case No. PU-23-341	Return on Equity
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/23	Oklahoma Gas & Electric	Cause No. PUD2023-000087	Return on Equity
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
Cascade Natural Gas Corporation	11/25	Cascade Natural Gas Corporation	UG 525	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/24	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-433	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	11/25	Pennsylvania-American Water Company	Docket No. R-2025-3057983 (water) Docket No. R-2025-3058051 (wastewater)	Return on Equity
American Water Works Company Inc.	11/23	Pennsylvania-American Water Company	Docket No. R-2023-3043189 (water) Docket No. R-2023-3043190 (wastewater)	Return on Equity
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
Otter Tail Power Co.	06/25	Otter Tail Power Co.	D-EL25-022	Return on Equity
Montana-Dakota Utilities Co.	10/23	Montana-Dakota Utilities Co.	Docket No. EL23-020	Return on Equity
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Tennessee Public Utility Commission				
Tennessee American Water Company	04/24	Tennessee American Water Company	Docket No.24-00032	Return on Equity
Texas Public Utility Commission				
Sharyland Utilities, L.L.C.	05/25	Sharyland Utilities, L.L.C.	Docket No. 57994	Return on Equity
Electric Transmission Texas LLC	02/25	Electric Transmission Texas LLC	Docket No. 57518	Return on Equity
CenterPoint Energy Houston	03/24	CenterPoint Energy Houston	D-56211	Return on Equity
AEP Texas	02/24	AEP Texas	D-56165	Return on Equity
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Texas Railroad Commission				
CenterPoint Energy Entex and CenterPoint Energy Texas Gas	10/23	CenterPoint Energy Entex and CenterPoint Energy Texas Gas	2023 Texas Division Rate Case Case No. OS-23-00015513	Return on Equity
Utah Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
PacifiCorp d/b/a Rocky Mountain Power	06/24	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 24-035-04	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/25	Virginia American Water Company, Inc.	Docket No. PUR-2025-00185	Return on Equity
Virginia American Water Company, Inc.	11/23	Virginia American Water Company, Inc.	Docket No. PUR-2023-00194	Return on Equity
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
Cascade Natural Gas Corporation	03/24	Cascade Natural Gas Corporation	Docket No. UG-240008	Return on Equity
Puget Sound Energy Inc.	02/24	Puget Sound Energy Inc.	Docket No. UE-240004 UG-240005	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/23	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-230172	Return on Equity
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	05/25	West Virginia American Water Company	Case No. 25-____-W-42T	Return on Equity
West Virginia American Water Company	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Power and Light	04/24	Wisconsin Power and Light	Docket No. 6680-UR-128	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/24	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-111	Return on Equity
Wisconsin Power and Light	05/23	Wisconsin Power and Light	Docket No. 6680-UR-124	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
Montana-Dakota Utilities Co.	06/25	Montana-Dakota Utilities Co.	Docket No. 20004-174-ER-25	Return on Equity
Montana-Dakota Utilities Co.	10/24	Montana-Dakota Utilities Co.	Docket No. 30013-415-GR-24	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	08/24	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-671-ER-24	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	02/23	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-633-ER-23	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts

Docket No. UE 470
Exhibit PAC/402
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Summary of Results

May 2026

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	9.36%	10.63%	11.66%
90-Day Avg. Stock Price	9.47%	10.74%	11.77%
180-Day Avg. Stock Price	9.56%	10.83%	11.86%
Average	9.46%	10.73%	11.76%
Median Results:			
30-Day Avg. Stock Price	9.68%	10.53%	11.34%
90-Day Avg. Stock Price	9.78%	10.63%	11.46%
180-Day Avg. Stock Price	9.84%	10.72%	11.61%
Average	9.77%	10.62%	11.47%

Multi-Stage DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.21%	9.70%	10.17%
90-Day Avg. Stock Price	9.33%	9.83%	10.31%
180-Day Avg. Stock Price	9.42%	9.94%	10.43%
Average	9.32%	9.83%	10.30%
Median Results:			
30-Day Avg. Stock Price	9.16%	9.50%	9.94%
90-Day Avg. Stock Price	9.27%	9.62%	10.03%
180-Day Avg. Stock Price	9.43%	9.78%	10.12%
Average	9.29%	9.63%	10.03%

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	11.02%	11.01%	10.97%
Long-term Avg. *Value Line* Beta	11.04%	11.03%	11.00%
ECAPM:			
Current *Value Line* Beta	11.51%	11.51%	11.48%
Long-term Avg. *Value Line* Beta	11.53%	11.52%	11.49%
Bond Yield Risk Premium	10.76%	10.74%	10.65%

Docket No. UE 470
Exhibit PAC/403
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Proxy Group Selection

May 2026

PROXY GROUP SCREENING DATA AND RESULTS

Company	Ticker	[1] Dividends	[2] S&P Credit Rating Between BBB- and AAA	[3] Positive Growth Rates from at least two sources (S&P Capital IQ, Value Line, and Zacks)	[4] Generation Assets Included in Rate Base	[5] Net Generation as a % of Total Sales > 30%	[6] Regulated Operating Income / Total Operating Income > 60%	[7] Announced Merger
Alliant Energy Corporation	LNT	Yes	BBB+	Yes	Yes	76.11%	96.94%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	71.06%	100.00%	No
American Electric Power Company, Inc.	AEP	Yes	BBB+	Yes	Yes	53.12%	99.09%	No
Avista Corporation	AVA	Yes	BBB	Yes	Yes	60.63%	100.00%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	50.66%	101.89%	No
Dominion Resources, Inc.	D	Yes	BBB+	Yes	Yes	77.34%	96.93%	No
DTE Energy Company	DTE	Yes	BBB+	Yes	Yes	84.78%	88.25%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	72.59%	97.27%	No
Evergy, Inc.	EVRG	Yes	BBB+	Yes	Yes	59.95%	100.00%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	64.28%	99.99%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	Yes	96.46%	83.75%	No
OGE Energy Corporation	OGE	Yes	BBB+	Yes	Yes	41.91%	100.00%	No
Pinnacle West Capital Corporation	PNW	Yes	BBB+	Yes	Yes	69.56%	100.00%	No
PPL Corporation	PPL	Yes	A-	Yes	Yes	41.60%	100.00%	No
Southern Company	SO	Yes	A-	Yes	Yes	76.82%	95.32%	No
Xcel Energy Inc.	XEL	Yes	BBB+	Yes	Yes	58.19%	100.00%	No

Notes:
[1] Bloomberg Professional
[2] Bloomberg Professional
[3] S&P Capital IQ, Value Line Investment Survey, and Zacks
[4] S&P Capital IQ Pro
[5] S&P Capital IQ Pro
[6] Form 10-K's for 2024, 2023, and 2022
[7] S&P Capital IQ Pro Financial News Releases

Docket No. UE 470
Exhibit PAC/404
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Constant Growth Discounted Cash Flow Model

May 2026

30-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] Zacks Projected EPS Growth Rate	[7] S&P Capital IQ 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	$2.14	$68.21	3.14%	3.25%	6.00%	7.20%	7.69%	6.96%	9.23%	10.21%	10.95%
Ameren Corporation	AEE	$2.84	$106.45	2.67%	2.77%	6.50%	9.30%	8.09%	7.96%	9.25%	10.74%	12.09%
American Electric Power Company, In	AEP	$3.80	$123.02	3.09%	3.20%	6.50%	6.70%	8.30%	7.17%	9.69%	10.37%	11.52%
Avista Corporation	AVA	$1.97	$40.90	4.82%	4.97%	6.50%	7.10%	6.01%	6.54%	10.98%	11.51%	12.09%
CMS Energy Corporation	CMS	$2.28	$73.13	3.12%	3.24%	8.50%	7.30%	7.54%	7.78%	10.53%	11.02%	11.75%
Dominion Resources, Inc.	D	$2.67	$61.93	4.31%	4.48%	6.50%	10.30%	6.91%	7.90%	10.95%	12.38%	14.83%
DTE Energy Company	DTE	$4.66	$139.12	3.35%	3.45%	4.50%	7.10%	7.03%	6.21%	7.92%	9.66%	10.57%
Entergy Corporation	ETR	$2.56	$99.07	2.58%	2.69%	3.00%	11.50%	11.20%	8.57%	5.62%	11.26%	14.23%
Evergy, Inc.	EVRG	$2.78	$78.68	3.53%	3.65%	7.50%	5.90%	7.22%	6.87%	9.54%	10.53%	11.17%
IDACORP, Inc.	IDA	$3.52	$136.59	2.58%	2.67%	6.00%	8.00%	8.34%	7.45%	8.65%	10.12%	11.02%
NextEra Energy, Inc.	NEE	$2.49	$88.71	2.81%	2.92%	8.00%	8.10%	7.06%	7.72%	9.96%	10.64%	11.02%
OGE Energy Corporation	OGE	$1.70	$45.14	3.77%	3.88%	6.50%	5.80%	6.43%	6.24%	9.68%	10.13%	10.39%
Pinnacle West Capital Corporation	PNW	$3.64	$95.21	3.82%	3.93%	5.00%	3.60%	7.67%	5.42%	7.49%	9.35%	11.64%
PPL Corporation	PPL	$1.09	$36.74	2.97%	3.08%	7.50%	7.30%	7.56%	7.45%	10.38%	10.53%	10.64%
Southern Company	SO	$2.96	$90.70	3.26%	3.38%	6.50%	7.20%	7.36%	7.02%	9.87%	10.40%	10.74%
Xcel Energy Inc.	XEL	$2.28	$78.21	2.92%	3.03%	7.00%	8.90%	8.70%	8.20%	10.02%	11.23%	11.95%
Mean										9.36%	10.63%	11.66%
Median										9.68%	10.53%	11.34%

Notes:
[1] Bloomberg Professional as of February 28, 2026
[2] Bloomberg Professional 30-day average as of February 28, 2026
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ
[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	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] Zacks Projected EPS Growth Rate	[7] S&P Capital IQ 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	$2.14	$66.75	3.21%	3.32%	6.00%	7.20%	7.69%	6.96%	9.30%	10.28%	11.02%
Ameren Corporation	AEE	$2.84	$103.11	2.75%	2.86%	6.50%	9.30%	8.09%	7.96%	9.34%	10.83%	12.18%
American Electric Power Company, In	AEP	$3.80	$118.97	3.19%	3.31%	6.50%	6.70%	8.30%	7.17%	9.80%	10.48%	11.63%
Avista Corporation	AVA	$1.97	$39.47	4.99%	5.15%	6.50%	7.10%	6.01%	6.54%	11.16%	11.69%	12.27%
CMS Energy Corporation	CMS	$2.28	$72.03	3.17%	3.29%	8.50%	7.30%	7.54%	7.78%	10.58%	11.07%	11.80%
Dominion Resources, Inc.	D	$2.67	$59.86	4.46%	4.64%	6.50%	10.30%	6.91%	7.90%	11.11%	12.54%	14.99%
DTE Energy Company	DTE	$4.66	$135.08	3.45%	3.56%	4.50%	7.10%	7.03%	6.21%	8.03%	9.77%	10.67%
Entergy Corporation	ETR	$2.56	$95.42	2.68%	2.80%	3.00%	11.50%	11.20%	8.57%	5.72%	11.36%	14.34%
Evergy, Inc.	EVRG	$2.78	$76.13	3.65%	3.78%	7.50%	5.90%	7.22%	6.87%	9.66%	10.65%	11.29%
IDACORP, Inc.	IDA	$3.52	$130.81	2.69%	2.79%	6.00%	8.00%	8.34%	7.45%	8.77%	10.24%	11.14%
NextEra Energy, Inc.	NEE	$2.49	$84.04	2.97%	3.08%	8.00%	8.10%	7.06%	7.72%	10.13%	10.80%	11.19%
OGE Energy Corporation	OGE	$1.70	$44.13	3.85%	3.97%	6.50%	5.80%	6.43%	6.24%	9.76%	10.22%	10.48%
Pinnacle West Capital Corporation	PNW	$3.64	$90.46	4.02%	4.13%	5.00%	3.60%	7.67%	5.42%	7.70%	9.56%	11.85%
PPL Corporation	PPL	$1.09	$35.88	3.04%	3.15%	7.50%	7.30%	7.56%	7.45%	10.45%	10.60%	10.71%
Southern Company	SO	$2.96	$89.25	3.32%	3.43%	6.50%	7.20%	7.36%	7.02%	9.92%	10.45%	10.79%
Xcel Energy Inc.	XEL	$2.28	$77.58	2.94%	3.06%	7.00%	8.90%	8.70%	8.20%	10.04%	11.26%	11.97%
Mean										9.47%	10.74%	11.77%
Median										9.78%	10.63%	11.46%

Notes:
[1] Bloomberg Professional as of February 28, 2026
[2] Bloomberg Professional 90-day average as of February 28, 2026
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ
[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	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] Zacks Projected EPS Growth Rate	[7] S&P Capital IQ 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	$2.14	$65.00	3.29%	3.41%	6.00%	7.20%	7.69%	6.96%	9.39%	10.37%	11.11%
Ameren Corporation	AEE	$2.84	$100.87	2.82%	2.93%	6.50%	9.30%	8.09%	7.96%	9.41%	10.89%	12.25%
American Electric Power Company, In	AEP	$3.80	$113.15	3.36%	3.48%	6.50%	6.70%	8.30%	7.17%	9.97%	10.65%	11.80%
Avista Corporation	AVA	$1.97	$37.81	5.21%	5.38%	6.50%	7.10%	6.01%	6.54%	11.38%	11.92%	12.50%
CMS Energy Corporation	CMS	$2.28	$71.25	3.20%	3.32%	8.50%	7.30%	7.54%	7.78%	10.62%	11.11%	11.84%
Dominion Resources, Inc.	D	$2.67	$58.62	4.56%	4.74%	6.50%	10.30%	6.91%	7.90%	11.20%	12.64%	15.09%
DTE Energy Company	DTE	$4.66	$135.02	3.45%	3.56%	4.50%	7.10%	7.03%	6.21%	8.03%	9.77%	10.67%
Entergy Corporation	ETR	$2.56	$91.12	2.81%	2.93%	3.00%	11.50%	11.20%	8.57%	5.85%	11.50%	14.47%
Evergy, Inc.	EVRG	$2.78	$73.39	3.79%	3.92%	7.50%	5.90%	7.22%	6.87%	9.80%	10.79%	11.43%
IDACORP, Inc.	IDA	$3.52	$126.39	2.78%	2.89%	6.00%	8.00%	8.34%	7.45%	8.87%	10.33%	11.24%
NextEra Energy, Inc.	NEE	$2.49	$78.51	3.18%	3.30%	8.00%	8.10%	7.06%	7.72%	10.34%	11.02%	11.40%
OGE Energy Corporation	OGE	$1.70	$44.06	3.86%	3.98%	6.50%	5.80%	6.43%	6.24%	9.77%	10.22%	10.48%
Pinnacle West Capital Corporation	PNW	$3.64	$89.23	4.08%	4.19%	5.00%	3.60%	7.67%	5.42%	7.75%	9.61%	11.91%
PPL Corporation	PPL	$1.09	$35.61	3.06%	3.18%	7.50%	7.30%	7.56%	7.45%	10.47%	10.63%	10.74%
Southern Company	SO	$2.96	$90.39	3.27%	3.39%	6.50%	7.20%	7.36%	7.02%	9.88%	10.41%	10.75%
Xcel Energy Inc.	XEL	$2.28	$74.75	3.05%	3.18%	7.00%	8.90%	8.70%	8.20%	10.16%	11.37%	12.09%
Mean										9.56%	10.83%	11.86%
Median										9.84%	10.72%	11.61%

Notes:
[1] Bloomberg Professional as of February 28, 2026
[2] Bloomberg Professional 180-day average as of February 28, 2026
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ
[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 470
Exhibit PAC/405
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

May 2026

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

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	4.79%	0.80	12.99%	8.20%	11.35%	11.76%
Ameren Corporation	AEE	4.79%	0.80	12.99%	8.20%	11.35%	11.76%
American Electric Power Company, Inc.	AEP	4.79%	0.70	12.99%	8.20%	10.53%	11.15%
Avista Corporation	AVA	4.79%	0.70	12.99%	8.20%	10.53%	11.15%
CMS Energy Corporation	CMS	4.79%	0.70	12.99%	8.20%	10.53%	11.15%
Dominion Resources, Inc.	D	4.79%	0.80	12.99%	8.20%	11.35%	11.76%
DTE Energy Company	DTE	4.79%	0.80	12.99%	8.20%	11.35%	11.76%
Entergy Corporation	ETR	4.79%	0.75	12.99%	8.20%	10.94%	11.45%
Evergy, Inc.	EVRG	4.79%	0.75	12.99%	8.20%	10.94%	11.45%
IDACORP, Inc.	IDA	4.79%	0.70	12.99%	8.20%	10.53%	11.15%
NextEra Energy, Inc.	NEE	4.79%	0.90	12.99%	8.20%	12.17%	12.38%
OGE Energy Corporation	OGE	4.79%	0.85	12.99%	8.20%	11.76%	12.07%
Pinnacle West Capital Corporation	PNW	4.79%	0.75	12.99%	8.20%	10.94%	11.45%
PPL Corporation	PPL	4.79%	0.80	12.99%	8.20%	11.35%	11.76%
Southern Company	SO	4.79%	0.65	12.99%	8.20%	10.12%	10.84%
Xcel Energy Inc.	XEL	4.79%	0.70	12.99%	8.20%	10.53%	11.15%
Mean						11.02%	11.51%
Median						10.94%	11.45%

Notes:

[1] Bloomberg Professional 30-day average as of February 28, 2026
[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 (Q2 2026 - Q2 2027)	[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	4.76%	0.80	12.99%	8.23%	11.35%	11.76%
Ameren Corporation	AEE	4.76%	0.80	12.99%	8.23%	11.35%	11.76%
American Electric Power Company, Inc.	AEP	4.76%	0.70	12.99%	8.23%	10.52%	11.14%
Avista Corporation	AVA	4.76%	0.70	12.99%	8.23%	10.52%	11.14%
CMS Energy Corporation	CMS	4.76%	0.70	12.99%	8.23%	10.52%	11.14%
Dominion Resources, Inc.	D	4.76%	0.80	12.99%	8.23%	11.35%	11.76%
DTE Energy Company	DTE	4.76%	0.80	12.99%	8.23%	11.35%	11.76%
Entergy Corporation	ETR	4.76%	0.75	12.99%	8.23%	10.93%	11.45%
Evergy, Inc.	EVRG	4.76%	0.75	12.99%	8.23%	10.93%	11.45%
IDACORP, Inc.	IDA	4.76%	0.70	12.99%	8.23%	10.52%	11.14%
NextEra Energy, Inc.	NEE	4.76%	0.90	12.99%	8.23%	12.17%	12.38%
OGE Energy Corporation	OGE	4.76%	0.85	12.99%	8.23%	11.76%	12.07%
Pinnacle West Capital Corporation	PNW	4.76%	0.75	12.99%	8.23%	10.93%	11.45%
PPL Corporation	PPL	4.76%	0.80	12.99%	8.23%	11.35%	11.76%
Southern Company	SO	4.76%	0.65	12.99%	8.23%	10.11%	10.83%
Xcel Energy Inc.	XEL	4.76%	0.70	12.99%	8.23%	10.52%	11.14%
Mean						11.01%	11.51%
Median						10.93%	11.45%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 45, No. 3, February 27, 2026, 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 (2027 - 2031)	Beta (β)	Market Return (Rm)	Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Alliant Energy Corporation	LNT	4.60%	0.80	12.99%	8.39%	11.31%	11.73%
Ameren Corporation	AEE	4.60%	0.80	12.99%	8.39%	11.31%	11.73%
American Electric Power Company, Inc.	AEP	4.60%	0.70	12.99%	8.39%	10.47%	11.10%
Avista Corporation	AVA	4.60%	0.70	12.99%	8.39%	10.47%	11.10%
CMS Energy Corporation	CMS	4.60%	0.70	12.99%	8.39%	10.47%	11.10%
Dominion Resources, Inc.	D	4.60%	0.80	12.99%	8.39%	11.31%	11.73%
DTE Energy Company	DTE	4.60%	0.80	12.99%	8.39%	11.31%	11.73%
Entergy Corporation	ETR	4.60%	0.75	12.99%	8.39%	10.89%	11.42%
Evergy, Inc.	EVRG	4.60%	0.75	12.99%	8.39%	10.89%	11.42%
IDACORP, Inc.	IDA	4.60%	0.70	12.99%	8.39%	10.47%	11.10%
NextEra Energy, Inc.	NEE	4.60%	0.90	12.99%	8.39%	12.15%	12.36%
OGE Energy Corporation	OGE	4.60%	0.85	12.99%	8.39%	11.73%	12.05%
Pinnacle West Capital Corporation	PNW	4.60%	0.75	12.99%	8.39%	10.89%	11.42%
PPL Corporation	PPL	4.60%	0.80	12.99%	8.39%	11.31%	11.73%
Southern Company	SO	4.60%	0.65	12.99%	8.39%	10.06%	10.79%
Xcel Energy Inc.	XEL	4.60%	0.70	12.99%	8.39%	10.47%	11.10%
Mean						10.97%	11.48%
Median						10.89%	11.42%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, 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 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	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	4.79%	0.80	12.99%	8.20%	11.32%	11.73%
Ameren Corporation	AEE	4.79%	0.76	12.99%	8.20%	11.05%	11.54%
American Electric Power Company, Inc.	AEP	4.79%	0.74	12.99%	8.20%	10.87%	11.40%
Avista Corporation	AVA	4.79%	0.69	12.99%	8.20%	10.42%	11.06%
CMS Energy Corporation	CMS	4.79%	0.80	12.99%	8.20%	11.32%	11.73%
Dominion Resources, Inc.	D	4.79%	0.70	12.99%	8.20%	10.57%	11.18%
DTE Energy Company	DTE	4.79%	0.69	12.99%	8.20%	10.42%	11.06%
Entergy Corporation	ETR	4.79%	0.76	12.99%	8.20%	11.05%	11.54%
Evergy, Inc.	EVRG	4.79%	0.94	12.99%	8.20%	12.48%	12.61%
IDACORP, Inc.	IDA	4.79%	0.74	12.99%	8.20%	10.87%	11.40%
NextEra Energy, Inc.	NEE	4.79%	0.75	12.99%	8.20%	10.98%	11.48%
OGE Energy Corporation	OGE	4.79%	0.76	12.99%	8.20%	11.05%	11.54%
Pinnacle West Capital Corporation	PNW	4.79%	0.94	12.99%	8.20%	12.51%	12.63%
PPL Corporation	PPL	4.79%	0.76	12.99%	8.20%	11.05%	11.54%
Southern Company	SO	4.79%	0.68	12.99%	8.20%	10.38%	11.04%
Xcel Energy Inc.	XEL	4.79%	0.67	12.99%	8.20%	10.31%	10.98%
Mean						11.04%	11.53%
Median						11.02%	11.51%

Notes:
[1] Bloomberg Professional 30-day average as of February 28, 2026
[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 (Q2 2026 - Q2 2027)	[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	4.76%	0.80	12.99%	8.23%	11.31%	11.73%
Ameren Corporation	AEE	4.76%	0.76	12.99%	8.23%	11.05%	11.53%
American Electric Power Company, Inc.	AEP	4.76%	0.74	12.99%	8.23%	10.86%	11.39%
Avista Corporation	AVA	4.76%	0.69	12.99%	8.23%	10.41%	11.06%
CMS Energy Corporation	CMS	4.76%	0.80	12.99%	8.23%	11.31%	11.73%
Dominion Resources, Inc.	D	4.76%	0.70	12.99%	8.23%	10.56%	11.17%
DTE Energy Company	DTE	4.76%	0.69	12.99%	8.23%	10.41%	11.06%
Entergy Corporation	ETR	4.76%	0.76	12.99%	8.23%	11.05%	11.53%
Evergy, Inc.	EVRG	4.76%	0.94	12.99%	8.23%	12.48%	12.61%
IDACORP, Inc.	IDA	4.76%	0.74	12.99%	8.23%	10.86%	11.39%
NextEra Energy, Inc.	NEE	4.76%	0.75	12.99%	8.23%	10.97%	11.48%
OGE Energy Corporation	OGE	4.76%	0.76	12.99%	8.23%	11.05%	11.53%
Pinnacle West Capital Corporation	PNW	4.76%	0.94	12.99%	8.23%	12.51%	12.63%
PPL Corporation	PPL	4.76%	0.76	12.99%	8.23%	11.05%	11.53%
Southern Company	SO	4.76%	0.68	12.99%	8.23%	10.37%	11.03%
Xcel Energy Inc.	XEL	4.76%	0.67	12.99%	8.23%	10.30%	10.97%
Mean						11.03%	11.52%
Median						11.01%	11.51%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 45, No. 3, February 27, 2026, 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 (2027 - 2031)	Beta (β)	Market Return (Rm)	Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Alliant Energy Corporation	LNT	4.60%	0.80	12.99%	8.39%	11.28%	11.71%
Ameren Corporation	AEE	4.60%	0.76	12.99%	8.39%	11.01%	11.50%
American Electric Power Company, Inc.	AEP	4.60%	0.74	12.99%	8.39%	10.82%	11.36%
Avista Corporation	AVA	4.60%	0.69	12.99%	8.39%	10.36%	11.02%
CMS Energy Corporation	CMS	4.60%	0.80	12.99%	8.39%	11.28%	11.71%
Dominion Resources, Inc.	D	4.60%	0.70	12.99%	8.39%	10.51%	11.13%
DTE Energy Company	DTE	4.60%	0.69	12.99%	8.39%	10.36%	11.02%
Entergy Corporation	ETR	4.60%	0.76	12.99%	8.39%	11.01%	11.50%
Evergy, Inc.	EVRG	4.60%	0.94	12.99%	8.39%	12.47%	12.60%
IDACORP, Inc.	IDA	4.60%	0.74	12.99%	8.39%	10.82%	11.36%
NextEra Energy, Inc.	NEE	4.60%	0.75	12.99%	8.39%	10.93%	11.45%
OGE Energy Corporation	OGE	4.60%	0.76	12.99%	8.39%	11.01%	11.50%
Pinnacle West Capital Corporation	PNW	4.60%	0.94	12.99%	8.39%	12.50%	12.62%
PPL Corporation	PPL	4.60%	0.76	12.99%	8.39%	11.01%	11.50%
Southern Company	SO	4.60%	0.68	12.99%	8.39%	10.32%	10.99%
Xcel Energy Inc.	XEL	4.60%	0.67	12.99%	8.39%	10.25%	10.93%
Mean						11.00%	11.49%
Median						10.97%	11.48%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, 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 470
Exhibit PAC/406
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Long-Term Beta Coefficient

May 2026

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] 12/31/2024	[13] 12/31/2025	[14] Average
Alliant Energy Corporation	LNT	0.75	0.80	0.80	0.75	0.80	0.65	0.65	0.85	0.90	0.90	0.90	0.90	0.80	0.80
Ameren Corporation	AEE	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.85	0.90	0.90	0.75	0.76
American Electric Power Company, Inc	AEP	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.85	0.90	0.80	0.70	0.74
Avista Corporation	AVA	0.70	0.70	0.70	0.65	0.65	0.55	0.55	0.75	0.75	0.75	0.80	0.95	0.70	0.69
CMS Energy Corporation	CMS	0.75	0.80	0.80	0.70	0.75	0.65	0.60	0.95	0.95	0.90	0.90	0.85	0.70	0.80
Dominion Resources, Inc.	D	0.70	0.70	0.75	0.65	0.65	0.55	0.50	0.80	0.80	0.80	0.85	0.90	0.80	0.70
DTE Energy Company	DTE	0.65	0.60	0.65	0.60	0.60	0.50	0.50	0.85	0.85	0.85	0.90	1.00	0.80	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	1.00	0.75	0.76
Evergy, Inc.	EVRG						NMF	NMF	1.00	0.95	0.90	0.90	0.95	0.75	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	0.85	0.65	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	1.05	0.90	0.75
OGE Energy Corporation	OGE	0.70	0.70	0.70	0.70	0.70	0.55	0.60	0.95	0.95	0.90	0.95	1.10	0.85	0.76
Pinnacle West Capital Corporation	PNW	0.85	0.90	0.95	0.90	0.95	0.85	0.75	1.10	1.05	1.00	1.05	0.95	0.75	0.94
PPL Corporation	PPL	0.75	0.80	0.80	0.70	0.70	0.60	0.55	0.85	0.90	0.85	0.90	1.10	0.80	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	0.95	0.65	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	0.85	0.70	0.67
Mean		0.72	0.73	0.75	0.68	0.69	0.58	0.57	0.88	0.88	0.87	0.91	0.94	0.75	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 29, 2023
[12] Value Line, Dated December 27, 2024.
[13] Value Line, Dated December 26, 2025.
[14] Average ([1] - [13])

Docket No. UE 470
Exhibit PAC/407
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Market Return

May 2026

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.27%
[2] Estimate of the S&P 500 Growth Rate	11.65%
[3] S&P 500 Estimated Required Market Return	12.99%

		[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.
Agilent Technologies Inc	A	282.83964	121.38	34,331.08	0.09%	0.84%	0.00%	7.99%	0.01%
Apple Inc	AAPL	14681.14	264.18	3,878,463.57	10.48%	0.39%	0.04%	13.33%	1.40%
AbbVie Inc	ABBV	1768.16901	232.08	410,356.66	1.11%	2.98%	0.03%	19.68%	0.22%
Airbnb Inc	ABNB	423.57328	135.11	57,228.99	0.15%			16.62%	0.03%
Abbott Laboratories	ABT	1737.68289	116.35	202,179.40	0.55%	2.17%	0.01%	10.11%	0.06%
Arch Capital Group Ltd	ACGL	355.80332	100.15	35,633.70	0.10%			2.64%	0.00%
Accenture PLC	ACN	615.30676	208.72	128,426.83		3.12%			
Adobe Inc	ADBE	410.5	262.41	107,719.31	0.29%			13.73%	0.04%
Analog Devices Inc	ADI	488.20416	354.6796	173,156.06		1.24%		22.33%	
Archer-Daniels-Midland Co	ADM	481.20184	69.04	33,222.18	0.09%	3.01%	0.00%	18.91%	0.02%
Automatic Data Processing Inc	ADP	402.64436	214.36	86,310.85		3.17%			
Autodesk Inc	ADSK	212	245.87	52,124.44				21.63%	
Ameren Corp	AEE	276.42452	113.28	31,313.37	0.08%	2.65%	0.00%	8.44%	0.01%
American Electric Power Co Inc	AEP	540.86147	133.82	72,378.08	0.20%	2.84%	0.01%	7.91%	0.02%
AES Corp/The	AES	712.12094	17.28	12,305.45	0.03%	4.07%	0.00%	11.17%	0.00%
Aflac Inc	AFL	516.36945	112.93	58,313.60		2.16%			
American International Group Inc	AIG	536.55966	80.49	43,187.69		2.24%			
Assurant Inc	AIZ	49.69977	229.59	11,410.57		1.53%			
Arthur J Gallagher & Co	AJG	257.1	228.2	58,670.22		1.23%			
Akamai Technologies Inc	AKAM	144.88811	98.39	14,255.54	0.04%			5.96%	0.00%
Albemarle Corp	ALB	117.84722	178.67	21,055.76		0.91%		175.50%	
Align Technology Inc	ALGN	71.28213	190.1	13,550.73				-2.94%	
Allstate Corp/The	ALL	259.53584	213.4401	55,395.36		2.02%		-1.75%	
Allegion plc	ALLE	86.14548	161.15	13,882.34	0.04%	1.37%	0.00%	5.28%	0.00%
Applied Materials Inc	AMAT	793.60987	372.3	295,460.95	0.80%	0.49%	0.00%	18.89%	0.15%
Amcor PLC	AMCR	462.04569	48.43	22,376.87	0.06%	5.37%	0.00%	9.93%	0.01%
Advanced Micro Devices Inc	AMD	1630.41084	200.21	326,424.55				48.15%	
AMETEK Inc	AME	228.9772	239.22	54,775.93	0.15%	0.57%	0.00%	9.07%	0.01%
Amgen Inc	AMGN	539.06768	388.16	209,244.51	0.57%	2.60%	0.01%	1.00%	0.01%
Ameriprise Financial Inc	AMP	91.179	470.12	42,865.07	0.12%	1.36%	0.00%	10.31%	0.01%
American Tower Corp	AMT	466.08482	191.86	89,423.03		3.54%			

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.
Amazon.com Inc	AMZN	10734.92087	210	2,254,333.38	6.09%			18.30%	1.11%
Arista Networks Inc	ANET	1256.53791	133.5	167,747.81	0.45%			17.94%	0.08%
Aon PLC	AON	214.2545	335.47	71,875.96		0.89%			
A O Smith Corp	AOS	113.37212	78	8,843.03		1.85%			
APA Corp	APA	353.25148	30.37	10,728.25		3.29%		-23.17%	
Air Products and Chemicals Inc	APD	222.65601	275.67	61,379.58	0.17%	2.63%	0.00%	6.86%	0.01%
Amphenol Corp	APH	1229.21493	146.06	179,539.13		0.68%		21.90%	
Apollo Global Management Inc	APO	578.24734	104.6	60,484.67	0.16%	1.95%	0.00%	14.55%	0.02%
AppLovin Corp	APP	307.07	434.77	133,504.82				47.15%	
Aptiv PLC	APTV	212.7484	73.54	15,645.52					
Alexandria Real Estate Equities Inc	ARE	173.30036	54.04	9,365.15		5.33%		-10.82%	
Ares Management Corp	ARES	220.90261	112.01	24,743.30		4.82%		28.84%	
Atmos Energy Corp	ATO	165.43895	186.79	30,902.34	0.08%	2.14%	0.00%	9.02%	0.01%
AvalonBay Communities Inc	AVB	140.08347	177.23	24,826.99	0.07%	4.02%	0.00%	4.13%	0.00%
Broadcom Inc	AVGO	4741.2738	319.55	1,515,074.04		0.81%		35.56%	
Avery Dennison Corp	AVY	76.87794	196.35	15,094.98	0.04%	1.91%	0.00%	5.53%	0.00%
American Water Works Co Inc	AWK	195.20867	136.03	26,554.24	0.07%	2.43%	0.00%	7.04%	0.01%
Axon Enterprise Inc	AXON	80.39768	542.4	43,607.70				33.23%	
American Express Co	AXP	686.61401	308.9	212,095.07	0.57%	1.06%	0.01%	14.24%	0.08%
AutoZone Inc	AZO	16.56782	3755.58	62,221.77	0.17%			14.21%	0.02%
Boeing Co/The	BA	785.3471	227.53	178,690.03					
Bank of America Corp	BAC	7176.68217	49.83	357,614.07		2.25%			
Ball Corp	BALL	266.07718	66.93	17,808.55	0.05%	1.20%	0.00%	13.36%	0.01%
Baxter International Inc	BAX	514.49005	20.37	10,480.16		0.20%		-2.87%	
Best Buy Co Inc	BBY	209.5351	61.97	12,984.89	0.04%	6.13%	0.00%	4.46%	0.00%
Becton Dickinson & Co	BDX	284.74181	176.48	50,251.23	0.14%	2.38%	0.00%	1.10%	0.00%
Franklin Resources Inc	BEN	520.76345	26.54	13,821.06	0.04%	4.97%	0.00%	12.01%	0.00%
Brown-Forman Corp	BF/B	294.59468	28.86	8,502.00	0.02%	3.20%	0.00%	2.43%	0.00%
Bunge Global SA	BG	193.50908	120.65	23,346.87	0.06%	2.32%	0.00%	19.44%	0.01%
Biogen Inc	BIIB	146.75853	191.82	28,151.22	0.08%			4.41%	0.00%
Bank of New York Mellon Corp/The	BK	686.9074	119.1	81,810.67	0.22%	1.78%	0.00%	12.87%	0.03%
Booking Holdings Inc	BKNG	31.67335	4239.35	134,274.42	0.36%	0.99%	0.00%	16.40%	0.06%
Baker Hughes Co	BKR	988.23651	65.26	64,492.31	0.17%	1.41%	0.00%	14.08%	0.02%
Builders FirstSource Inc	BLDR	110.60507	104.29	11,535.00	0.03%			10.56%	0.00%
Blackrock Inc	BLK	155.54154	1063.23	165,376.43	0.45%	2.16%	0.01%	15.14%	0.07%
Bristol-Myers Squibb Co	BMY	2036.47371	62.37	127,014.87		4.04%		53.01%	
Broadridge Financial Solutions Inc	BR	116.74872	185.87	21,700.08		2.10%			
Berkshire Hathaway Inc	BRK/B	1372.82014	504.95	693,205.53					
Brown & Brown Inc	BRO	340.42002	71.82	24,448.97		0.92%			
Boston Scientific Corp	BSX	1483.88546	76.85	114,036.60	0.31%			13.45%	0.04%

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Blackstone Inc	BX	742.18074	113.37	84,141.03		5.26%		20.02%	
BXP Inc	BXP	158.62912	57.58	9,133.86	0.02%	4.86%	0.00%	3.36%	0.00%
Citigroup Inc	C	1749.31901	110.19	192,757.46	0.52%	2.18%	0.01%	19.71%	0.10%
Conagra Brands Inc	CAG	478.36948	19.25	9,208.61		7.27%		-8.19%	
Cardinal Health Inc	CAH	235.31602	229.23	53,941.49	0.15%	0.89%	0.00%	14.74%	0.02%
Carrier Global Corp	CARR	835.84388	64.4	53,828.35	0.15%	1.49%	0.00%	9.39%	0.01%
Caterpillar Inc	CAT	465.28733	742.83	345,629.39		0.81%		25.31%	
Chubb Ltd	CB	390.15655	340.86	132,988.76	0.36%	1.14%	0.00%	3.42%	0.01%
Cboe Global Markets Inc	CBOE	104.6677	299.72	31,371.00	0.08%	0.96%	0.00%	13.75%	0.01%
CBRE Group Inc	CBRE	295.15855	147.66	43,583.11					
Crown Castle Inc	CCI	436.07044	89.54	39,045.75		4.75%			
Carnival Corp	CCL	1236.70661	31.55	39,018.09	0.11%	1.90%	0.00%	11.20%	0.01%
Cadence Design Systems Inc	CDNS	275.87547	301.4	83,148.87	0.22%			14.61%	0.03%
CDW Corp/DE	CDW	128.99359	122.64	15,819.77	0.04%	2.05%	0.00%	7.25%	0.00%
Constellation Energy Corp	CEG	362.35548	329.88	119,533.83	0.32%	0.52%	0.00%	15.42%	0.05%
CF Industries Holdings Inc	CF	153.66882	99.54	15,296.19		2.01%		-16.61%	
Citizens Financial Group Inc	CFG	424.98366	60.19	25,579.77		3.06%		24.19%	
Church & Dwight Co Inc	CHD	236.69424	104.86	24,819.76	0.07%	1.17%	0.00%	7.21%	0.00%
CH Robinson Worldwide Inc	CHRW	118.62083	185.25	21,974.51	0.06%	1.36%	0.00%	17.23%	0.01%
Charter Communications Inc	CHTR	126.63155	234.63	29,711.56				21.90%	
Cigna Group/The	CI	263.52828	289.82	76,375.77	0.21%	2.15%	0.00%	9.89%	0.02%
Ciena Corp	CIEN	141.46346	348.7	49,328.31				41.75%	
Cincinnati Financial Corp	CINF	155.61758	163.98	25,518.17	0.07%	2.29%	0.00%	5.30%	0.00%
Colgate-Palmolive Co	CL	801.54803	99.14	79,465.47	0.21%	2.10%	0.00%	5.54%	0.01%
Clorox Co/The	CLX	120.91186	127.16	15,375.15		3.90%		-0.22%	
Comcast Corp	CMCSA	3588.40162	30.96	111,096.91		4.26%		-3.89%	
CME Group Inc	CME	358.62233	319.5	114,579.83	0.31%	1.63%	0.01%	5.82%	0.02%
Chipotle Mexican Grill Inc	CMG	1302.423	37.22	48,476.18	0.13%			12.82%	0.02%
Cummins Inc	CMI	138.16546	583.87	80,670.67	0.22%	1.37%	0.00%	14.29%	0.03%
CMS Energy Corp	CMS	306.4209	78.07	23,922.28	0.06%	2.92%	0.00%	7.27%	0.00%
Centene Corp	CNC	491.771	44.88	22,070.68				42.35%	
CenterPoint Energy Inc	CNP	652.86827	43.5	28,399.77	0.08%	2.11%	0.00%	8.95%	0.01%
Capital One Financial Corp	COF	621.93159	195.64	121,674.70	0.33%	1.64%	0.01%	13.86%	0.05%
Coinbase Global Inc	COIN	223.04128	175.85	39,221.81				23.32%	
Cooper Cos Inc/The	COO	195.1142	83.67	16,325.21	0.04%			7.77%	0.00%
ConocoPhillips	COP	1222.33915	113.46	138,686.60		2.96%			
Cencora Inc	COR	194.53068	372.14	72,392.65	0.20%	0.64%	0.00%	10.42%	0.02%
Costco Wholesale Corp	COST	443.86941	1010.79	448,658.76	1.21%	0.51%	0.01%	11.37%	0.14%
Corpay Inc	CPAY	68.0503	325.1	22,123.15	0.06%			12.37%	0.01%
Campbell's Company/The	CPB	298.13425	26.95	8,034.72		5.79%		-3.24%	

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Copart Inc	CPRT	968.01768	38.09	36,871.79					
Camden Property Trust	CPT	103.40821	108.34	11,203.25	0.03%	3.91%	0.00%	2.13%	0.00%
CRH PLC	CRH	668.25082	119.98	80,176.73	0.22%	1.30%	0.00%	9.98%	0.02%
Charles River Laboratories International Inc	CRL	49.2278	178.49	8,786.67	0.02%			7.41%	0.00%
Salesforce Inc	CRM	937	194.79	182,518.23	0.49%	0.90%	0.00%	12.79%	0.06%
Crowdstrike Holdings Inc	CRWD	252.09844	371.98	93,775.58				23.15%	
Cisco Systems Inc	CSCO	3949.89304	79.46	313,858.50	0.85%	2.11%	0.02%	7.80%	0.07%
CoStar Group Inc	CSGP	419.7933	44.63	18,735.37				42.74%	
CSX Corp	CSX	1859.5568	42.69	79,384.48	0.21%	1.31%	0.00%	14.00%	0.03%
Cintas Corp	CTAS	399.88965	201.13	80,429.81	0.22%	0.89%	0.00%	10.79%	0.02%
Coterra Energy Inc	CTRA	759.27272	30.59	23,226.15		2.88%		23.71%	
Cognizant Technology Solutions Corp	CTSH	478.24692	64.43	30,813.45		2.05%			
Corteva Inc	CTVA	683.01458	79.94	54,600.19	0.15%	0.90%	0.00%	9.29%	0.01%
Carvana Co	CVNA	142.7362	334.16	47,696.73					
CVS Health Corp	CVS	1272.21106	79.9	101,649.66	0.27%	3.33%	0.01%	13.13%	0.04%
Chevron Corp	CVX	1995.38554	186.76	372,658.20		3.81%		-8.85%	
Dominion Energy Inc	D	878.78563	63.14	55,486.52	0.15%	4.23%	0.01%	13.32%	0.02%
Delta Air Lines Inc	DAL	653.13071	65.7	42,910.69	0.12%	1.14%	0.00%	14.65%	0.02%
DoorDash Inc	DASH	409.96686	176.47	72,346.85				39.94%	
DuPont de Nemours Inc	DD	408.92386	49.84	20,380.77	0.06%	1.61%	0.00%	17.42%	0.01%
Datadog Inc	DDOG	328.48336	111.96	36,777.00				24.38%	
Deere & Co	DE	270.10728	629.71	170,089.26	0.46%	1.03%	0.00%	16.83%	0.08%
Deckers Outdoor Corp	DECK	141.94997	117.27	16,646.47	0.04%			6.38%	0.00%
Dell Technologies Inc	DELL	333.91781	148.08	49,446.55	0.13%	1.42%	0.00%	18.13%	0.02%
Dollar General Corp	DG	220.11887	156.24	34,391.37	0.09%	1.51%	0.00%	8.97%	0.01%
Quest Diagnostics Inc	DGX	109.86632	211.91	23,281.77	0.06%	1.62%	0.00%	7.25%	0.00%
DR Horton Inc	DHI	289.7034	160.39	46,465.53	0.13%	1.12%	0.00%	5.46%	0.01%
Danaher Corp	DHR	707.13936	210.64	148,951.83	0.40%	0.76%	0.00%	7.82%	0.03%
Walt Disney Co/The	DIS	1771.51985	106.04	187,851.96	0.51%	1.41%	0.01%	11.32%	0.06%
Digital Realty Trust Inc	DLR	343.61544	177.2	60,888.66	0.16%	2.75%	0.00%	7.38%	0.01%
Dollar Tree Inc	DLTR	198.85319	126.48	25,150.95	0.07%			11.87%	0.01%
Healthpeak Properties Inc	DOC	695.044	17.68	12,288.38	0.03%	6.90%	0.00%	1.08%	0.00%
Dover Corp	DOV	134.86663	225.5	30,412.43	0.08%	0.92%	0.00%	9.65%	0.01%
Dow Inc	DOW	705.76446	30.73	21,688.14		4.56%		54.00%	
Domino's Pizza Inc	DPZ	33.6289	402.51	13,535.97	0.04%	1.98%	0.00%	11.36%	0.00%
Darden Restaurants Inc	DRI	115.13925	213.85	24,622.53	0.07%	2.81%	0.00%	10.65%	0.01%
DTE Energy Co	DTE	207.68301	148.24	30,786.93	0.08%	3.14%	0.00%	7.38%	0.01%
Duke Energy Corp	DUK	778	130.85	101,801.30	0.28%	3.26%	0.01%	6.69%	0.02%
DaVita Inc	DVA	66.8	156.3	10,440.84				25.82%	
Devon Energy Corp	DVN	620	43.53	26,988.60	0.07%	2.21%	0.00%	1.93%	0.00%

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Dexcom Inc	DXCM	384.86484	73.43	28,260.63	0.08%			16.87%	0.01%
Electronic Arts Inc	EA	250.25371	200.57	50,193.39	0.14%	0.38%	0.00%	13.01%	0.02%
eBay Inc	EBAY	448	90.86	40,705.28	0.11%	1.36%	0.00%	9.91%	0.01%
Ecolab Inc	ECL	281.96945	308.35	86,945.28	0.23%	0.95%	0.00%	12.93%	0.03%
Consolidated Edison Inc	ED	361.24744	112.52	40,647.56	0.11%	3.15%	0.00%	7.39%	0.01%
Equifax Inc	EFX	120.27	208.96	25,131.62	0.07%	1.07%	0.00%	17.72%	0.01%
Everest Group Ltd	EG	40.39015	335.49	13,550.49		2.38%		26.06%	
Edison International	EIX	384.79093	74.74	28,759.27	0.08%	4.70%	0.00%	7.58%	0.01%
Estee Lauder Cos Inc/The	EL	247.2197	109.47	27,063.14		1.28%		39.63%	
Elevance Health Inc	ELV	220.70467	320	70,625.49	0.19%	2.15%	0.00%	2.04%	0.00%
EMCOR Group Inc	EME	44.53257	724.62	32,269.19		0.22%			
Emerson Electric Co	EMR	562	150.75	84,721.50	0.23%	1.47%	0.00%	10.43%	0.02%
EOG Resources Inc	EOG	536.49149	124.08	66,567.86		3.29%		-1.03%	
EPAM Systems Inc	EPAM	54.13997	141	7,633.74					
Equinix Inc	EQIX	98.25493	974.26	95,725.85	0.26%	2.12%	0.01%	15.00%	0.04%
Equity Residential	EQR	377.54711	63.21	23,864.75	0.06%	4.38%	0.00%	3.24%	0.00%
EQT Corp	EQT	624.274	61.42	38,342.91		1.07%		34.05%	
Erie Indemnity Co	ERIE	46.18907	269.44	12,445.18		2.17%			
Eversource Energy	ES	375.49661	76.21	28,616.60	0.08%	4.13%	0.00%	4.71%	0.00%
Essex Property Trust Inc	ESS	64.47551	255.11	16,448.35	0.04%	4.06%	0.00%	1.99%	0.00%
Eaton Corp PLC	ETN	387.9	375.92	145,819.37		1.17%			
Entergy Corp	ETR	452.98984	107.11	48,519.74	0.13%	2.39%	0.00%	11.15%	0.01%
Evergy Inc	EVRG	229.74594	83.66	19,220.55	0.05%	3.32%	0.00%	5.91%	0.00%
Edwards Lifesciences Corp	EW	580.8	86.47	50,221.78	0.14%			12.45%	0.02%
Exelon Corp	EXC	1009.53563	49.05	49,517.72	0.13%	3.43%	0.00%	5.92%	0.01%
Expand Energy Corp	EXE	240.39826	107.92	25,943.78		2.13%		58.23%	
Expeditors International of Washington Inc	EXPD	133.50368	145.03	19,362.04	0.05%	1.06%	0.00%	8.97%	0.00%
Expedia Group Inc	EXPE	117.01142	215.69	25,238.19		0.89%		21.20%	
Extra Space Storage Inc	EXR	211.13767	151.03	31,888.12	0.09%	4.29%	0.00%	2.03%	0.00%
Ford Motor Co	F	3918.62315	14.09	55,213.40		4.26%			
Diamondback Energy Inc	FANG	282.07899	174.08	49,104.31		2.41%		-5.23%	
Fastenal Co	FAST	1148.32851	46.04	52,869.04	0.14%	2.09%	0.00%	11.48%	0.02%
Freeport-McMoRan Inc	FCX	1437.20161	68.08	97,844.69		0.88%		27.40%	
FactSet Research Systems Inc	FDS	37.09926	216.81	8,043.49	0.02%	2.03%	0.00%	4.86%	0.00%
FedEx Corp	FDX	235.12282	387	90,992.53	0.25%	1.50%	0.00%	11.09%	0.03%
FirstEnergy Corp	FE	577.12618	51.16	29,525.78	0.08%	3.64%	0.00%	7.29%	0.01%
F5 Inc	FFIV	56.51927	271.36	15,337.07	0.04%			2.91%	0.00%
Fair Isaac Corp	FICO	23.72213	1409.36	33,433.02				31.35%	
Fidelity National Information Services Inc	FIS	514.40369	50.96	26,214.01		3.45%			
Fiserv Inc	FISV	534.77751	62.29	33,311.29					

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
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Fifth Third Bancorp	FITB	899.70015	49.47	44,508.17		3.23%			
Comfort Systems USA Inc	FIX	35.17497	1429.37	50,278.05		0.20%		24.00%	
Fox Corp	FOX	224.70222	51.73	11,623.85	0.03%	1.08%	0.00%	1.58%	0.00%
Fox Corp	FOXA	200.69386	56.34	11,307.09	0.03%	0.99%	0.00%	1.58%	0.00%
Federal Realty Investment Trust	FRT	86.27603	108.77	9,384.24	0.03%	4.16%	0.00%	4.66%	0.00%
First Solar Inc	FSLR	107.31099	197.2	21,161.73				37.78%	
Fortinet Inc	FTNT	739.92358	79.03	58,476.16					
Fortive Corp	FTV	307.85919	59.2	18,225.26		0.41%			
General Dynamics Corp	GD	270.38976	357.05	96,542.66	0.26%	1.68%	0.00%	10.51%	0.03%
GoDaddy Inc	GDDY	133.35412	87.16	11,623.15					
General Electric Co	GE	1048.81361	342.26	358,966.95	0.97%	0.55%	0.01%	15.18%	0.15%
GE HealthCare Technologies Inc	GEHC	455.74977	84.27	38,406.03	0.10%	0.17%	0.00%	10.18%	0.01%
Gen Digital Inc	GEN	605.66377	22.57	13,669.83	0.04%	2.22%	0.00%	13.08%	0.00%
GE Vernova Inc	GEV	269.52946	873.6	235,460.94		0.23%		67.22%	
Gilead Sciences Inc	GILD	1241.42053	148.95	184,909.59	0.50%	2.20%	0.01%	7.32%	0.04%
General Mills Inc	GIS	533.58208	45.23	24,133.92		5.39%		-6.42%	
Globe Life Inc	GL	78.63713	145.26	11,422.83		0.91%			
Corning Inc	GLW	857.94811	150.38	129,018.24		0.74%		26.81%	
General Motors Co	GM	903.96785	78.71	71,151.31		0.91%			
Generac Holdings Inc	GNRC	58.67583	225.37	13,223.77					
Alphabet Inc	GOOG	5438	311.43	1,693,556.34	4.58%	0.27%	0.01%	10.11%	0.46%
Alphabet Inc	GOOGL	5822	311.76	1,815,066.72	4.90%	0.27%	0.01%	10.11%	0.50%
Genuine Parts Co	GPC	139.12211	119.26	16,591.70		3.56%			
Global Payments Inc	GPN	279.90133	76.46	21,401.26		1.31%			
Garmin Ltd	GRMN	192.48083	252.83	48,664.93	0.13%	1.66%	0.00%	8.88%	0.01%
Goldman Sachs Group Inc/The	GS	296.75292	855.07	253,744.52	0.69%	2.11%	0.01%	14.78%	0.10%
WW Grainger Inc	GWW	47.37302	1144.73	54,229.32	0.15%	0.79%	0.00%	8.76%	0.01%
Halliburton Co	HAL	837.54835	36	30,151.74	0.08%	1.89%	0.00%	7.42%	0.01%
Hasbro Inc	HAS	140.68576	99.59	14,010.89	0.04%	2.81%	0.00%	10.25%	0.00%
Huntington Bancshares Inc/OH	HBAN	2030	16.8	34,104.00		3.69%			
HCA Healthcare Inc	HCA	223.6222	529.7	118,452.68	0.32%	0.59%	0.00%	8.56%	0.03%
Home Depot Inc/The	HD	995.51149	380.72	379,011.13	1.02%	2.45%	0.03%	6.09%	0.06%
Hartford Insurance Group Inc/The	HIG	275.86322	140.2301	38,684.33		1.71%			
Huntington Ingalls Industries Inc	HII	39.24269	444.52	17,444.16	0.05%	1.24%	0.00%	17.55%	0.01%
Hilton Worldwide Holdings Inc	HLT	229.29162	311.78	71,488.54	0.19%	0.19%	0.00%	12.94%	0.02%
Hologic Inc	HOLX	223.24491	75.36	16,823.74	0.05%			9.00%	0.00%
Honeywell International Inc	HON	635.6757	243.59	154,844.24	0.42%	1.95%	0.01%	7.71%	0.03%
Robinhood Markets Inc	HOOD	790.05465	75.85	59,925.65	0.16%			17.60%	0.03%
Hewlett Packard Enterprise Co	HPE	1328.80844	21.47	28,529.52	0.08%	2.65%	0.00%	18.64%	0.01%
HP Inc	HPQ	914.5502	18.99	17,367.31	0.05%	6.32%	0.00%	1.27%	0.00%

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Hormel Foods Corp	HRL	550.28421	25.6	14,087.28	0.04%	4.57%	0.00%	6.61%	0.00%
Henry Schein Inc	HSIC	114.70412	82.39	9,450.47	0.03%			7.01%	0.00%
Host Hotels & Resorts Inc	HST	687.80218	19.59	13,474.04		4.08%		-1.83%	
Hershey Co/The	HSY	148.07744	236.28	34,987.74	0.09%	2.46%	0.00%	16.20%	0.02%
Hubbell Inc	HUBB	53.1616	511.63	27,199.07		1.11%			
Humana Inc	HUM	120.59597	190.54	22,978.36	0.06%	1.86%	0.00%	14.94%	0.01%
Howmet Aerospace Inc	HWM	400.94006	262.53	105,258.79		0.18%		20.01%	
Interactive Brokers Group Inc	IBKR	445.43946	71.19	31,710.84	0.09%	0.45%	0.00%	15.21%	0.01%
International Business Machines Corp	IBM	938.0344	240.21	225,325.24	0.61%	2.80%	0.02%	6.14%	0.04%
Intercontinental Exchange Inc	ICE	567.89651	164.13	93,208.85	0.25%	1.27%	0.00%	16.14%	0.04%
IDEXX Laboratories Inc	IDXX	79.62403	656.73	52,291.49	0.14%			11.32%	0.02%
IDEX Corp	IEX	74.34782	209.47	15,573.64		1.36%			
International Flavors & Fragrances Inc	IFF	255.47749	82.23	21,007.91	0.06%	1.95%	0.00%	9.82%	0.01%
Incyte Corp	INCY	199.01449	101.27	20,154.20				25.00%	
Intel Corp	INTC	4995	45.61	227,821.95				27.92%	
Intuit Inc	INTU	276.55	409.03	113,117.25	0.31%	1.17%	0.00%	14.47%	0.04%
Invitation Homes Inc	INVH	609.38609	26.34	16,051.23	0.04%	4.56%	0.00%	3.54%	0.00%
International Paper Co	IP	529.46943	43.55	23,058.39		4.25%			
IQVIA Holdings Inc	IQV	169.7	178.81	30,344.06	0.08%			7.90%	0.01%
Ingersoll Rand Inc	IR	391.61799	94.14	36,866.92		0.08%			
Iron Mountain Inc	IRM	295.83521	108.33	32,047.83		3.19%			
Intuitive Surgical Inc	ISRG	355.13024	503.51	178,811.63	0.48%			12.37%	0.06%
Gartner Inc	IT	70.45029	157.2	11,074.79	0.03%			7.46%	0.00%
Illinois Tool Works Inc	ITW	288.2	290.63	83,759.57	0.23%	2.22%	0.01%	8.83%	0.02%
Invesco Ltd	IVZ	443.67378	26.26	11,650.87	0.03%	3.20%	0.00%	19.45%	0.01%
Jacobs Solutions Inc	J	117.44671	137.86	16,191.20	0.04%	1.04%	0.00%	13.57%	0.01%
JB Hunt Transport Services Inc	JBHT	94.60408	233.41	22,081.54	0.06%	0.77%	0.00%	16.39%	0.01%
Jabil Inc	JBL	105.59527	264.99	27,981.69	0.08%	0.12%	0.00%	14.77%	0.01%
Johnson Controls International plc	JCI	612.06621	144.3	88,321.15	0.24%	1.11%	0.00%	18.90%	0.05%
Jack Henry & Associates Inc	JKHY	72.16737	162.46	11,724.31		1.50%			
Johnson & Johnson	JNJ	2409.89894	248.43	598,691.19	1.62%	2.09%	0.03%	8.86%	0.14%
JPMorgan Chase & Co	JPM	2697.03238	300.3	809,918.82	2.19%	2.00%	0.04%	11.12%	0.24%
Keurig Dr Pepper Inc	KDP	1358.66606	30.28	41,140.41	0.11%	3.04%	0.00%	8.93%	0.01%
KeyCorp	KEY	1089.64743	20.5367	22,377.76	0.06%	3.99%	0.00%	18.71%	0.01%
Keysight Technologies Inc	KEYS	171.8	307.33	52,799.29	0.14%			17.45%	0.02%
Kraft Heinz Co/The	KHC	1183.74475	24.61	29,131.96		6.50%		-6.02%	
Kimco Realty Corp	KIM	679.49863	23.55	16,002.19	0.04%	4.42%	0.00%	3.32%	0.00%
KKR & Co Inc	KKR	891.55089	87.68	78,171.18		0.84%			
KLA Corp	KLAC	131.07661	1524.55	199,832.85	0.54%	0.50%	0.00%	13.99%	0.08%
Kimberly-Clark Corp	KMB	331.92237	111.44	36,989.43	0.10%	4.59%	0.00%	4.12%	0.00%

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Kinder Morgan Inc	KMI	2224.8064	33.27	74,019.31		3.52%			
Coca-Cola Co/The	KO	4300.72307	81.56	350,766.97	0.95%	2.60%	0.02%	7.24%	0.07%
Kroger Co/The	KR	632.84916	68.24	43,185.63	0.12%	2.05%	0.00%	6.90%	0.01%
Kenvue Inc	KVUE	1916.73209	19.12	36,647.92	0.10%	4.34%	0.00%	13.12%	0.01%
Loews Corp	L	206.05287	110.02	22,669.94		0.23%			
Leidos Holdings Inc	LDOS	126.39268	175.1	22,131.36	0.06%	0.98%	0.00%	11.62%	0.01%
Lennar Corp	LEN	216.50828	114.36	24,759.89	0.07%	1.75%	0.00%	12.35%	0.01%
Labcorp Holdings Inc	LH	82.4	289.12	23,823.49	0.06%	1.00%	0.00%	7.23%	0.00%
L3Harris Technologies Inc	LHX	186.77626	364.54	68,087.42	0.18%	1.37%	0.00%	13.72%	0.03%
Lennox International Inc	LII	34.80291	569.94	19,835.57		0.91%			
Linde PLC	LIN	463.39416	508.08	235,441.30	0.64%	1.26%	0.01%	9.05%	0.06%
Eli Lilly & Co	LLY	943.35742	1051.99	992,402.57	2.68%	0.66%	0.02%	14.00%	0.38%
Lockheed Martin Corp	LMT	230.08024	654.63	150,617.43		2.11%		20.87%	
Alliant Energy Corp	LNT	257.14083	72.34	18,601.57	0.05%	2.96%	0.00%	6.78%	0.00%
Lowe's Cos Inc	LOW	561	264.57	148,423.77	0.40%	1.81%	0.01%	3.65%	0.01%
Lam Research Corp	LRCX	1248.771	233.89	292,075.05		0.44%		21.18%	
Lululemon Athletica Inc	LULU	112.19004	185.17	20,774.23				-0.73%	
Southwest Airlines Co	LUV	491.31799	49.26	24,202.32		1.46%		82.46%	
Las Vegas Sands Corp	LVS	671.91072	56.72	38,110.78	0.10%	2.12%	0.00%	10.21%	0.01%
Lamb Weston Holdings Inc	LW	138.87988	48.19	6,692.62		3.15%		-6.94%	
LyondellBasell Industries NV	LYB	322.16998	56.83	18,308.92		4.86%		48.35%	
Live Nation Entertainment Inc	LYV	234.80192	162.14	38,070.78					
Mastercard Inc	MA	885.21639	517.21	457,842.77		0.67%			
Mid-America Apartment Communities Inc	MAA	116.90102	133.86	15,648.37	0.04%	4.57%	0.00%	0.61%	0.00%
Marriott International Inc/MD	MAR	264.98455	341.73	90,553.17	0.24%	0.78%	0.00%	11.09%	0.03%
Masco Corp	MAS	203.60709	71.62	14,582.34	0.04%	1.79%	0.00%	6.72%	0.00%
McDonald's Corp	MCD	710.39864	339.165	240,942.35	0.65%	2.19%	0.01%	9.05%	0.06%
Microchip Technology Inc	MCHP	541.13546	74.64	40,390.35		2.44%		34.96%	
McKesson Corp	MCK	122.48746	986.55	120,840.00	0.33%	0.33%	0.00%	14.56%	0.05%
Moody's Corp	MCO	177.3	476.5598	84,494.05	0.23%	0.86%	0.00%	12.16%	0.03%
Mondelez International Inc	MDLZ	1281.84567	61.58	78,936.06	0.21%	3.25%	0.01%	7.72%	0.02%
Medtronic PLC	MDT	1283.88496	97.66	125,384.21	0.34%	2.91%	0.01%	7.53%	0.03%
MetLife Inc	MET	652.05387	72.07	46,993.52	0.13%	3.15%	0.00%	12.62%	0.02%
Meta Platforms Inc	META	2187.17775	648.18	1,417,684.87	3.83%	0.32%	0.01%	17.07%	0.65%
MGM Resorts International	MGM	255.82852	36.86	9,429.84					
McCormick & Co Inc/MD	MKC	253.59054	71.04	18,015.07	0.05%	2.70%	0.00%	5.27%	0.00%
Martin Marietta Materials Inc	MLM	60.31205	675.74	40,755.26		0.49%		-7.47%	
3M Co	MMM	526.7	165.32	87,074.04	0.24%	1.89%	0.00%	6.70%	0.02%
Monster Beverage Corp	MNST	978.27073	85.3	83,446.49	0.23%			11.57%	0.03%
Altria Group Inc	MO	1671.89809	69.04	115,427.84	0.31%	6.14%	0.02%	2.81%	0.01%

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Molina Healthcare Inc	MOH	51.5	154.05	7,933.58	0.02%			19.43%	0.00%
Mosaic Co/The	MOS	317.50526	27.84	8,839.35	0.02%	3.16%	0.00%	10.89%	0.00%
Marathon Petroleum Corp	MPC	294.74016	198.21	58,420.45		2.02%			
Monolithic Power Systems Inc	MPWR	49.118	1142.74	56,129.10		0.70%			
Merck & Co Inc	MRK	2472.392	123.82	306,131.58		2.75%			
Moderna Inc	MRNA	394.93942	53.57	21,156.90				24.62%	
Marsh & McLennan Cos Inc	MRSH	484.12425	186.74	90,405.36		1.93%			
Morgan Stanley	MS	1587.86021	166.51	264,394.60	0.71%	2.40%	0.02%	9.41%	0.07%
MSCI Inc	MSCI	73.47404	571.83	42,014.66	0.11%	1.43%	0.00%	13.40%	0.02%
Microsoft Corp	MSFT	7425.62908	392.74	2,916,341.56		0.93%			
Motorola Solutions Inc	MSI	165.65891	482.26	79,890.67	0.22%	1.00%	0.00%	8.80%	0.02%
M&T Bank Corp	MTB	149.00025	215.48	32,106.57	0.09%	2.78%	0.00%	11.47%	0.01%
Match Group Inc	MTCH	232.64448	31.6	7,351.57	0.02%	2.53%	0.00%	16.50%	0.00%
Mettler-Toledo International Inc	MTD	20.32525	1366.69	27,778.32	0.08%			10.25%	0.01%
Micron Technology Inc	MU	1125.50926	412.37	464,126.25		0.11%		59.90%	
Norwegian Cruise Line Holdings Ltd	NCLH	455.25749	24.79	11,285.83	0.03%			14.54%	0.00%
Nasdaq Inc	NDAQ	568.44386	87.58	49,784.31	0.13%	1.23%	0.00%	16.20%	0.02%
Nordson Corp	NDSN	55.7836	293.44	16,369.14		1.12%			
NextEra Energy Inc	NEE	2083.52196	93.77	195,371.85	0.53%	2.66%	0.01%	7.70%	0.04%
Newmont Corp	NEM	1087.87421	129.7374	141,137.97		0.80%		-2.37%	
Netflix Inc	NFLX	4222.16215	96.24	406,340.89					
NiSource Inc	NI	478.53317	47.3	22,634.62	0.06%	2.54%	0.00%	8.27%	0.01%
NIKE Inc	NKE	1191.49565	61.77	73,598.69	0.20%	2.66%	0.01%	14.71%	0.03%
Northrop Grumman Corp	NOC	141.92162	724.38	102,805.18	0.28%	1.28%	0.00%	7.20%	0.02%
ServiceNow Inc	NOW	1046	108.01	112,978.46					
NRG Energy Inc	NRG	214.67754	178.96	38,418.69		1.06%			
Norfolk Southern Corp	NSC	224.57203	314.74	70,681.80		1.72%			
NetApp Inc	NTAP	197.3304	99.03	19,541.63	0.05%	2.10%	0.00%	4.98%	0.00%
Northern Trust Corp	NTRS	185.8278	143.09	26,590.10	0.07%	2.24%	0.00%	10.50%	0.01%
Nucor Corp	NUE	227.77462	176.88	40,288.77		1.27%		23.67%	
NVIDIA Corp	NVDA	24300	177.19	4,305,717.00		0.02%		42.55%	
NVR Inc	NVR	2.79376	7517.79	21,002.90	0.06%			7.04%	0.00%
News Corp	NWS	185.15227	26.78	4,958.38		0.75%			
News Corp	NWSA	370.22579	24.29	8,992.78		0.82%			
NXP Semiconductors NV	NXPI	252.69285	227.01	57,363.80	0.15%	1.79%	0.00%	14.09%	0.02%
Realty Income Corp	O	932.44022	67	62,473.49	0.17%	4.84%	0.01%	3.82%	0.01%
Old Dominion Freight Line Inc	ODFL	208.42562	203.05	42,320.82		0.57%			
ONEOK Inc	OKE	629.78363	82.77	52,127.19	0.14%	5.17%	0.01%	3.06%	0.00%
Omnicom Group Inc	OMC	310.33634	85.29	26,468.59	0.07%	3.75%	0.00%	6.79%	0.00%
ON Semiconductor Corp	ON	394.02053	66.48	26,194.48				24.64%	

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
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Oracle Corp	ORCL	2873.13	145.4	417,753.10		1.38%		26.75%	
O'Reilly Automotive Inc	ORLY	838.48703	93.88	78,717.16	0.21%			9.97%	0.02%
Otis Worldwide Corp	OTIS	388.72077	92.56	35,979.99		1.82%			
Occidental Petroleum Corp	OXY	986.26666	53.08	52,351.03		1.96%		-31.27%	
Palo Alto Networks Inc	PANW	816	148.92	121,518.72					
Paycom Software Inc	PAYC	54.2751	125.83	6,829.44		1.19%			
Paychex Inc	PAYX	358.96745	93.65	33,617.30		4.61%			
PACCAR Inc	PCAR	525.89444	126.09	66,310.03		1.05%		21.56%	
PG&E Corp	PCG	2197.96795	19	41,761.39	0.11%	1.05%	0.00%	12.55%	0.01%
Public Service Enterprise Group Inc	PEG	498.73991	86.07	42,926.54	0.12%	3.11%	0.00%	7.54%	0.01%
PepsiCo Inc	PEP	1366.64905	169.74	231,975.01	0.63%	3.35%	0.02%	5.84%	0.04%
Pfizer Inc	PFE	5686.26743	27.65	157,225.29		6.22%			
Principal Financial Group Inc	PFG	216.83514	95.42	20,690.41	0.06%	3.35%	0.00%	11.50%	0.01%
Procter & Gamble Co/The	PG	2324.00069	167.2	388,572.92	1.05%	2.53%	0.03%	4.48%	0.05%
Progressive Corp/The	PGR	586.1	213.66	125,226.13	0.34%	0.19%	0.00%	1.40%	0.00%
Parker-Hannifin Corp	PH	126.21653	1009.18	127,375.20	0.34%	0.71%	0.00%	10.02%	0.03%
PulteGroup Inc	PHM	192.32789	137.2	26,387.39	0.07%	0.76%	0.00%	5.96%	0.00%
Packaging Corp of America	PKG	89.21339	232.14	20,710.00	0.06%	2.15%	0.00%	11.62%	0.01%
Prologis Inc	PLD	926.175	142.57	132,044.77	0.36%	3.00%	0.01%	6.61%	0.02%
Palantir Technologies Inc	PLTR	2291.47075	137.19	314,366.87				47.57%	
Philip Morris International Inc	PM	1556.67958	186.83	290,834.45	0.79%	3.15%	0.02%	10.23%	0.08%
PNC Financial Services Group Inc/The	PNC	403.37092	212.35	85,655.81	0.23%	3.20%	0.01%	13.05%	0.03%
Pentair PLC	PNR	163.23571	99.19	16,191.35		1.09%			
Pinnacle West Capital Corp	PNW	120.90539	100.3	12,126.81	0.03%	3.63%	0.00%	7.00%	0.00%
Insulet Corp	PODD	70.39585	246.61	17,360.32				26.20%	
Pool Corp	POOL	36.78782	227.18	8,357.46	0.02%	2.20%	0.00%	7.73%	0.00%
PPG Industries Inc	PPG	223.49471	123.27	27,550.19	0.07%	2.30%	0.00%	8.75%	0.01%
PPL Corp	PPL	751.307	38.98	29,285.95	0.08%	2.92%	0.00%	8.40%	0.01%
Prudential Financial Inc	PRU	348	98.38	34,236.24		5.69%			
Public Storage	PSA	175.50645	307.06	53,891.01	0.15%	3.91%	0.01%	2.92%	0.00%
Paramount Skydance Corp	PSKY	1080.24102	13.51	14,594.06		1.48%			
Phillips 66	PSX	400.74402	154.33	61,846.82		3.29%			
PTC Inc	PTC	118.99612	156.59	18,633.60	0.05%			7.40%	0.00%
Quanta Services Inc	PWR	149.61943	563.08	84,247.71	0.23%	0.08%	0.00%	18.42%	0.04%
PayPal Holdings Inc	PYPL	920.66454	46.21	42,543.91	0.11%	1.21%	0.00%	13.23%	0.02%
Qnity Electronics Inc	Q	209.65891	126.76	26,576.36		0.25%			
QUALCOMM Inc	QCOM	1067	142.36	151,898.12	0.41%	2.50%	0.01%	2.35%	0.01%
Royal Caribbean Cruises Ltd	RCL	270.5283	310.96	84,123.48	0.23%	1.93%	0.00%	13.63%	0.03%
Regency Centers Corp	REG	182.90656	79	14,449.62	0.04%	3.82%	0.00%	4.80%	0.00%
Regeneron Pharmaceuticals Inc	REGN	103.90266	781.67	81,217.59	0.22%	0.48%	0.00%	12.00%	0.03%

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Regions Financial Corp	RF	863.50669	27.565	23,802.56	0.06%	3.85%	0.00%	8.79%	0.01%
Raymond James Financial Inc	RJF	197.09104	153.08	30,170.70	0.08%	1.41%	0.00%	14.18%	0.01%
Ralph Lauren Corp	RL	38.65514	362.6	14,016.35	0.04%	1.01%	0.00%	18.14%	0.01%
ResMed Inc	RMD	145.6784	256.26	37,331.55	0.10%	0.94%	0.00%	9.44%	0.01%
Rockwell Automation Inc	ROK	112.35791	407.45	45,780.23	0.12%	1.35%	0.00%	14.96%	0.02%
Rollins Inc	ROL	481.09222	60.89	29,293.71	0.08%	1.20%	0.00%	13.09%	0.01%
Roper Technologies Inc	ROP	102.92752	349.73	35,996.84		1.04%			
Ross Stores Inc	ROST	323.44493	205.64	66,513.22	0.18%	0.79%	0.00%	7.04%	0.01%
Republic Services Inc	RSG	308.80497	229	70,716.34	0.19%	1.09%	0.00%	7.99%	0.02%
RTX Corp	RTX	1342.28768	202.62	271,974.33	0.73%	1.34%	0.01%	10.12%	0.07%
Revvity Inc	RVTY	111.79937	98.31	10,991.00	0.03%	0.28%	0.00%	8.71%	0.00%
SBA Communications Corp	SBAC	105.78859	201.16	21,280.43		2.49%		-5.46%	
Starbucks Corp	SBUX	1139.3	98.02	111,674.19	0.30%	2.53%	0.01%	16.75%	0.05%
Charles Schwab Corp/The	SCHW	1752.21043	95.2	166,810.43	0.45%	1.34%	0.01%	15.22%	0.07%
Sherwin-Williams Co/The	SHW	247.77477	361.79	89,642.43	0.24%	0.88%	0.00%	10.95%	0.03%
J M Smucker Co/The	SJM	106.64832	115.95	12,365.87	0.03%	3.79%	0.00%	2.51%	0.00%
SLB Ltd	SLB	1501.1333	51.34	77,068.18	0.21%	2.30%	0.00%	5.03%	0.01%
Super Micro Computer Inc	SMCI	598.98943	32.39	19,401.27				28.11%	
Snap-on Inc	SNA	51.91312	385.22	19,997.97	0.05%	2.53%	0.00%	4.59%	0.00%
Sandisk Corp/DE	SNDK	153.38838	635.36	97,456.84					
Synopsys Inc	SNPS	191.56203	414	79,306.68	0.21%			14.46%	0.03%
Southern Co/The	SO	1100.1936	97.38	107,136.85	0.29%	3.04%	0.01%	7.18%	0.02%
Solventum Corp	SOLV	173.49301	74.2	12,873.18	0.03%			9.40%	0.00%
Simon Property Group Inc	SPG	324.94527	203.85	66,240.09	0.18%	4.32%	0.01%	1.62%	0.00%
S&P Global Inc	SPGI	306	441.88	135,215.28	0.37%	0.88%	0.00%	12.28%	0.04%
Sempra	SRE	652.68152	96.27	62,833.65	0.17%	2.73%	0.00%	6.99%	0.01%
STERIS PLC	STE	98.07503	252.35	24,749.23		1.00%			
Steel Dynamics Inc	STLD	144.8824	193.13	27,981.14		1.10%		27.32%	
State Street Corp	STT	278.72821	128.62	35,850.02	0.10%	2.61%	0.00%	9.85%	0.01%
Seagate Technology Holdings PLC	STX	218.07307	407.84	88,938.92		0.73%		38.04%	
Constellation Brands Inc	STZ	173.38463	157.86	27,370.50		2.58%		-1.97%	
Smurfit Westrock PLC	SW	524.25374	47.01	24,645.17		3.85%		65.65%	
Stanley Black & Decker Inc	SWK	155.07947	86.49	13,412.82		3.84%			
Skyworks Solutions Inc	SWKS	150.37361	59.58	8,959.26		4.77%		-4.65%	
Synchrony Financial	SYF	347.59628	69.11	24,022.38	0.06%	1.74%	0.00%	8.79%	0.01%
Stryker Corp	SYK	382.68868	387.46	148,276.56	0.40%	0.91%	0.00%	10.60%	0.04%
Sysco Corp	SYY	478.93065	91.16	43,659.32		2.37%			
AT&T Inc	T	7000.5772	28.01	196,086.17	0.53%	3.96%	0.02%	10.62%	0.06%
Molson Coors Beverage Co	TAP	175.59262	48.99	8,602.28		3.92%		-4.36%	
TransDigm Group Inc	TDG	56.47356	1302.79	73,573.19	0.20%			12.68%	0.03%

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.
Teledyne Technologies Inc	TDY	46.30531	681.1	31,538.55	0.09%			8.48%	0.01%
Bio-Techne Corp	TECH	156.45329	59	9,230.74	0.02%	0.54%	0.00%	10.00%	0.00%
TE Connectivity PLC	TEL	293.43427	230.15	67,533.90	0.18%	1.23%	0.00%	13.90%	0.03%
Teradyne Inc	TER	156.55595	320.03	50,102.60		0.16%		34.29%	
Truist Financial Corp	TFC	1249.16832	49.31	61,596.49	0.17%	4.22%	0.01%	13.18%	0.02%
Target Corp	TGT	452.80642	113.79	51,524.84		4.01%		-1.57%	
TJX Cos Inc/The	TJX	1110.4671	161.66	179,518.11	0.49%	1.05%	0.01%	8.25%	0.04%
TKO Group Holdings Inc	TKO	77.96634	223.87	17,454.32		1.39%		80.03%	
Thermo Fisher Scientific Inc	TMO	371.48424	521.11	193,584.15	0.52%	0.36%	0.00%	7.12%	0.04%
T-Mobile US Inc	TMUS	1101.86274	217.09	239,203.38		1.88%			
Texas Pacific Land Corp	TPL	68.94155	523.69	36,104.00		0.46%			
Tapestry Inc	TPR	202.46422	155.47	31,477.11	0.09%	1.03%	0.00%	13.83%	0.01%
Targa Resources Corp	TRGP	214.9518	235.8	50,685.63		2.12%		23.24%	
Trimble Inc	TRMB	233.92941	66.87	15,642.86					
T Rowe Price Group Inc	TROW	218.0729	94.63	20,636.24	0.06%	5.50%	0.00%	2.38%	0.00%
Travelers Cos Inc/The	TRV	216.2379	308.64	66,739.67		1.43%		-1.90%	
Tractor Supply Co	TSCO	526.35129	51.84	27,286.05	0.07%	1.85%	0.00%	8.35%	0.01%
Tesla Inc	TSLA	3752.43198	402.51	1,510,391.40					
Tyson Foods Inc	TSN	282.06996	64.99	18,331.73	0.05%	3.14%	0.00%	11.69%	0.01%
Trane Technologies PLC	TT	221.33191	462.32	102,326.17	0.28%	0.91%	0.00%	12.53%	0.03%
Trade Desk Inc/The	TTD	432.86842	23.82	10,310.93	0.03%			15.40%	0.00%
Take-Two Interactive Software Inc	TTWO	185.17546	211.48	39,160.91				62.23%	
Texas Instruments Inc	TXN	907.55077	212.11	192,500.59	0.52%	2.68%	0.01%	14.12%	0.07%
Textron Inc	TXT	174.16244	98.65	17,181.12	0.05%	0.08%	0.00%	10.14%	0.00%
Tyler Technologies Inc	TYL	42.98534	354.69	15,246.47					
United Airlines Holdings Inc	UAL	327.70387	106.3	34,834.92	0.09%			16.94%	0.02%
Uber Technologies Inc	UBER	2058.11598	75.42	155,223.11	0.42%			3.27%	0.01%
UDR Inc	UDR	328.57196	37.5	12,321.45	0.03%	4.59%	0.00%	1.17%	0.00%
Universal Health Services Inc	UHS	53.83786	205.9001	11,085.22	0.03%	0.39%	0.00%	6.82%	0.00%
Ulta Beauty Inc	ULTA	44.36217	684.79	30,378.77	0.08%			6.85%	0.01%
UnitedHealth Group Inc	UNH	905.83862	293.27	265,655.29	0.72%	3.01%	0.02%	11.94%	0.09%
Union Pacific Corp	UNP	593.39146	264.98	157,236.87	0.42%	2.08%	0.01%	8.21%	0.03%
United Parcel Service Inc	UPS	743.85583	115.96	86,257.52	0.23%	5.66%	0.01%	9.01%	0.02%
United Rentals Inc	URI	62.99815	840	52,918.45	0.14%	0.94%	0.00%	14.54%	0.02%
US Bancorp	USB	1553.6958	54.66	84,925.01	0.23%	3.81%	0.01%	11.13%	0.03%
Visa Inc	V	1681.09394	320.14	538,185.41	1.45%	0.84%	0.01%	13.86%	0.20%
VICI Properties Inc	VICI	1068.7373	30.21	32,286.55	0.09%	5.96%	0.01%	4.11%	0.00%
Valero Energy Corp	VLO	299.02623	204.64	61,192.73		2.35%			
Veralto Corp	VLTO	247.84336	97.43	24,147.38		0.53%			
Vulcan Materials Co	VMC	130.58038	310	40,479.92	0.11%	0.67%	0.00%	15.26%	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.
Verisk Analytics Inc	VRSK	137.94189	207.57	28,632.60	0.08%	0.96%	0.00%	11.03%	0.01%
VeriSign Inc	VRSN	91.7	227.94	20,902.10		1.42%			
Vertex Pharmaceuticals Inc	VRTX	254.03419	496.83	126,211.81					
Vistra Corp	VST	336.95426	173.89	58,592.98	0.16%	0.52%	0.00%	18.89%	0.03%
Ventas Inc	VTR	474.96522	86.16	40,923.00	0.11%	2.41%	0.00%	10.72%	0.01%
Viatris Inc	VTRS	1151.39292	14.93	17,190.30	0.05%	3.22%	0.00%	3.66%	0.00%
Verizon Communications Inc	VZ	4217.68417	50.14	211,474.68		5.64%			
Westinghouse Air Brake Technologies Corp	WAB	170.51719	263.95	45,008.01	0.12%	0.47%	0.00%	12.73%	0.02%
Waters Corp	WAT	98.10187	319.38	31,331.78	0.08%			11.70%	0.01%
Warner Bros Discovery Inc	WBD	2479.92951	28.17	69,859.61					
Workday Inc	WDAY	213	133.76	28,490.88					
Western Digital Corp	WDC	339.03792	279.7	94,828.91		0.18%		51.11%	
WEC Energy Group Inc	WEC	325.53136	116.96	38,074.15	0.10%	3.26%	0.00%	7.05%	0.01%
Welltower Inc	WELL	697.75253	207.12	144,518.50	0.39%	1.43%	0.01%	18.58%	0.07%
Wells Fargo & Co	WFC	3085.63564	81.45	251,325.02	0.68%	2.21%	0.02%	13.66%	0.09%
Waste Management Inc	WM	403.33578	240.84	97,139.39	0.26%	1.37%	0.00%	9.48%	0.02%
Williams Cos Inc/The	WMB	1221.56311	74.72	91,275.20		2.81%		24.06%	
Walmart Inc	WMT	7970.16696	127.95	1,019,782.86	2.76%	0.77%	0.02%	10.27%	0.28%
W R Berkley Corp	WRB	374.49086	71.7	26,850.99	0.07%	0.50%	0.00%	5.24%	0.00%
Williams-Sonoma Inc	WSM	119.38071	205.65	24,550.64	0.07%	1.28%	0.00%	4.68%	0.00%
West Pharmaceutical Services Inc	WST	72.02149	254.34	18,317.95	0.05%	0.35%	0.00%	11.11%	0.01%
Willis Towers Watson PLC	WTW	94.5459	305.17	28,852.57		1.26%			
Weyerhaeuser Co	WY	720.665	24.53	17,677.91		3.42%			
Wynn Resorts Ltd	WYNN	103.97448	108.19	11,249.00		0.92%			
Xcel Energy Inc	XEL	623.87681	83.36	52,006.37	0.14%	2.84%	0.00%	8.88%	0.01%
Exxon Mobil Corp	XOM	4166.76345	152.5	635,431.43		2.70%			
Xylem Inc/NY	XYL	243.14141	129.56	31,501.40		1.33%			
Block Inc	XYZ	539.103	63.7	34,340.86				29.74%	
Yum! Brands Inc	YUM	276.43013	168.16	46,484.49	0.13%	1.78%	0.00%	8.99%	0.01%
Zimmer Biomet Holdings Inc	ZBH	195.652	98.44	19,259.98	0.05%	0.98%	0.00%	5.83%	0.00%
Zebra Technologies Corp	ZBRA	49.1917	223.96	11,016.97					
Zoetis Inc	ZTS	422.12771	131.1	55,340.94	0.15%	1.62%	0.00%	9.00%	0.01%

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 February 28, 2026
[5] Bloomberg Professional as of February 28, 2026
[6] Equals [4] x [5]

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.

[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of February 28, 2026
[9] Equals [7] x [8]
[10] Value Line, as of February 28, 2026
[11] Equals [7] x [10]

Docket No. UE 470
Exhibit PAC/408
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

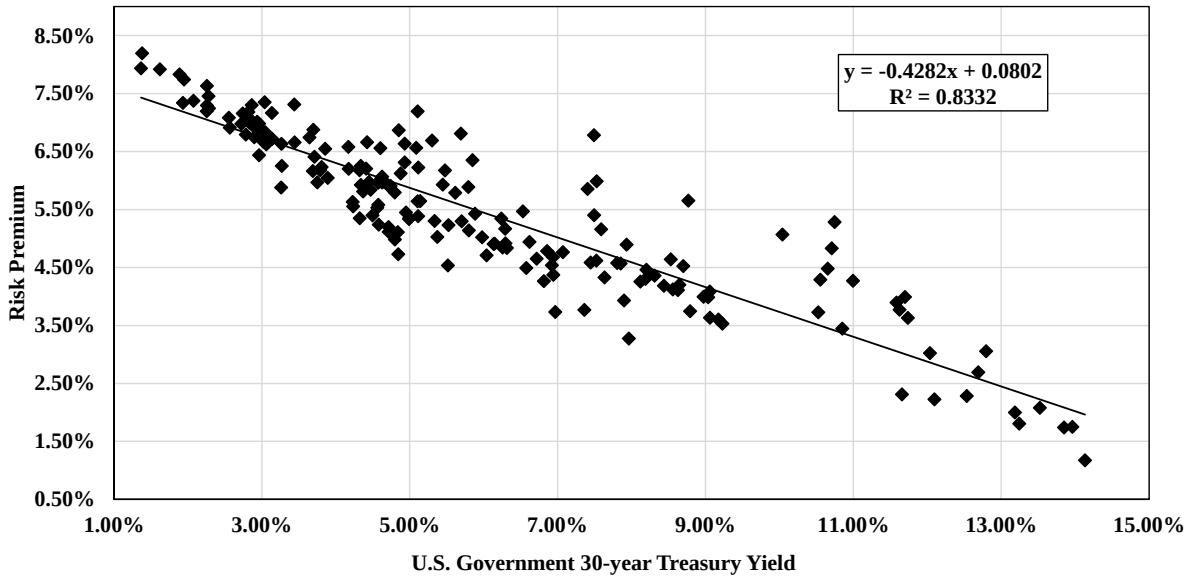
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Risk Premium Approach

May 2026



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9127980
R Square	0.8332003
Adjusted R Square	0.8322888
Standard Error	0.0057867
Observations	185

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03061	0.03061	914.12403	0.00000
Residual	183	0.00613	0.00003		
Total	184	0.03674			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0802	0.00	84.20	0.0000	0.0783	0.0820	0.0783	0.0820
U.S. Govt. 30-year Treasury	(0.4282)	0.01	(30.23)	0.0000	(0.4562)	(0.4003)	(0.4562)	(0.4003)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.79%	5.96%	10.76%
Blue Chip Near-Term Projected Forecast (Q2 2026 - Q2 2027) [5]	4.76%	5.98%	10.74%
Blue Chip Long-Term Projected Forecast (2027-2031) [6]	4.60%	6.05%	10.65%
AVERAGE			10.71%

Notes:
[1] Source: Regulatory Research Associates, rate cases through February 28, 2026
[2] Source: 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] Source: S&P Capital IQ Pro, 30-day average as of February 28, 2026
[5] Source: Blue Chip Financial Forecasts, Vol. 45, No. 3, February 27, 2026, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.080066 + (-0.427148 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] 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%
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%

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	9.54%	1.62%	7.92%
2021.1	9.45%	2.07%	7.38%
2021.2	9.55%	2.26%	7.30%
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	9.88%	3.05%	6.83%
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	10.04%	3.81%	6.23%
2023.3	9.79%	4.23%	5.55%
2023.4	9.82%	4.58%	5.24%
2024.1	9.67%	4.32%	5.35%
2024.2	10.16%	4.58%	5.58%
2024.3	9.86%	4.23%	5.63%
2024.4	9.90%	4.50%	5.40%
2025.1	9.83%	4.72%	5.11%
2025.2	9.95%	4.84%	5.11%
2025.3	9.58%	4.85%	4.73%
2025.4	9.91%	4.71%	5.20%
2026.1	9.78%	4.80%	4.98%
AVERAGE	11.45%	6.01%	5.44%
MEDIAN	10.94%	5.11%	5.55%

Docket No. UE 470
Exhibit PAC/409
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Multi-Stage Discounted Cash Flow Model

May 2026

MULTI-STAGE DCF

AVERAGE FIRST STAGE GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: **30** **DAYS**

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Company		Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Alliant Energy Corporation	LNT	$2.14	$68.21	6.00%	5.95%	5.91%	5.86%	5.81%	5.76%	5.72%	5.67%	5.62%	5.57%	5.53%	5.48%	9.03%
Ameren Corporation	AEE	$2.84	$106.45	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	8.66%
American Electric Power Company, Inc.	AEP	$3.80	$123.02	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	9.17%
Avista Corporation	AVA	$1.97	$40.90	6.01%	5.97%	5.92%	5.87%	5.82%	5.77%	5.72%	5.67%	5.62%	5.58%	5.53%	5.48%	10.96%
CMS Energy Corporation	CMS	$2.28	$73.13	7.30%	7.13%	6.97%	6.80%	6.64%	6.47%	6.31%	6.14%	5.98%	5.81%	5.64%	5.48%	9.53%
Dominion Resources, Inc.	D	$2.67	$61.93	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	10.62%
DTE Energy Company	DTE	$4.66	$139.12	4.50%	4.59%	4.68%	4.77%	4.86%	4.94%	5.03%	5.12%	5.21%	5.30%	5.39%	5.48%	8.68%
Entergy Corporation	ETR	$2.56	$99.07	3.00%	3.23%	3.45%	3.68%	3.90%	4.13%	4.35%	4.58%	4.80%	5.03%	5.25%	5.48%	7.47%
Evergy, Inc.	EVRG	$2.78	$78.68	5.90%	5.86%	5.82%	5.78%	5.75%	5.71%	5.67%	5.63%	5.59%	5.55%	5.52%	5.48%	9.44%
IDACORP, Inc.	IDA	$3.52	$136.59	6.00%	5.95%	5.91%	5.86%	5.81%	5.76%	5.72%	5.67%	5.62%	5.57%	5.53%	5.48%	8.38%
NextEra Energy, Inc.	NEE	$2.49	$88.71	7.06%	6.91%	6.77%	6.63%	6.48%	6.34%	6.20%	6.05%	5.91%	5.76%	5.62%	5.48%	9.05%
OGE Energy Corporation	OGE	$1.70	$45.14	5.80%	5.77%	5.74%	5.71%	5.68%	5.65%	5.62%	5.60%	5.57%	5.54%	5.51%	5.48%	9.66%
Pinnacle West Capital Corporation	PNW	$3.64	$95.21	3.60%	3.77%	3.94%	4.11%	4.28%	4.45%	4.62%	4.80%	4.97%	5.14%	5.31%	5.48%	8.80%
PPL Corporation	PPL	$1.09	$36.74	7.30%	7.13%	6.97%	6.80%	6.64%	6.47%	6.31%	6.14%	5.98%	5.81%	5.64%	5.48%	9.34%
Southern Company	SO	$2.96	$90.70	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	9.38%
Xcel Energy Inc.	XEL	$2.28	$78.21	7.00%	6.86%	6.72%	6.58%	6.45%	6.31%	6.17%	6.03%	5.89%	5.75%	5.62%	5.48%	9.16%
Mean					5.92%	5.88%	5.83%	5.79%	5.74%	5.70%	5.66%	5.61%	5.57%	5.52%	5.48%	9.21%
Median					6.19%	6.12%	6.04%	5.97%	5.90%	5.83%	5.76%	5.69%	5.62%	5.55%	5.48%	9.16%

Notes:
[1] Bloomberg Professional as of February 28, 2026
[2] Bloomberg Professional 30-day average as of February 28, 2026
[3] Attachment PAC/404
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Attachment PAC/410
[15] 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 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Alliant Energy Corporation	LNT	$2.14	$66.75	6.00%	5.95%	5.91%	5.86%	5.81%	5.76%	5.72%	5.67%	5.62%	5.57%	5.53%	5.48%	9.11%
Ameren Corporation	AEE	$2.84	$103.11	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	8.77%
American Electric Power Company, Inc.	AEP	$3.80	$118.97	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	9.29%
Avista Corporation	AVA	$1.97	$39.47	6.01%	5.97%	5.92%	5.87%	5.82%	5.77%	5.72%	5.67%	5.62%	5.58%	5.53%	5.48%	11.16%
CMS Energy Corporation	CMS	$2.28	$72.03	7.30%	7.13%	6.97%	6.80%	6.64%	6.47%	6.31%	6.14%	5.98%	5.81%	5.64%	5.48%	9.59%
Dominion Resources, Inc.	D	$2.67	$59.86	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	10.80%
DTE Energy Company	DTE	$4.66	$135.08	4.50%	4.59%	4.68%	4.77%	4.86%	4.94%	5.03%	5.12%	5.21%	5.30%	5.39%	5.48%	8.79%
Entergy Corporation	ETR	$2.56	$95.42	3.00%	3.23%	3.45%	3.68%	3.90%	4.13%	4.35%	4.58%	4.80%	5.03%	5.25%	5.48%	7.56%
Evergy, Inc.	EVRG	$2.78	$76.13	5.90%	5.86%	5.82%	5.78%	5.75%	5.71%	5.67%	5.63%	5.59%	5.55%	5.52%	5.48%	9.57%
IDACORP, Inc.	IDA	$3.52	$130.81	6.00%	5.95%	5.91%	5.86%	5.81%	5.76%	5.72%	5.67%	5.62%	5.57%	5.53%	5.48%	8.51%
NextEra Energy, Inc.	NEE	$2.49	$84.04	7.06%	6.91%	6.77%	6.63%	6.48%	6.34%	6.20%	6.05%	5.91%	5.76%	5.62%	5.48%	9.24%
OGE Energy Corporation	OGE	$1.70	$44.13	5.80%	5.77%	5.74%	5.71%	5.68%	5.65%	5.62%	5.60%	5.57%	5.54%	5.51%	5.48%	9.76%
Pinnacle West Capital Corporation	PNW	$3.64	$90.46	3.60%	3.77%	3.94%	4.11%	4.28%	4.45%	4.62%	4.80%	4.97%	5.14%	5.31%	5.48%	8.99%
PPL Corporation	PPL	$1.09	$35.88	7.30%	7.13%	6.97%	6.80%	6.64%	6.47%	6.31%	6.14%	5.98%	5.81%	5.64%	5.48%	9.43%
Southern Company	SO	$2.96	$89.25	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	9.44%
Xcel Energy Inc.	XEL	$2.28	$77.58	7.00%	6.86%	6.72%	6.58%	6.45%	6.31%	6.17%	6.03%	5.89%	5.75%	5.62%	5.48%	9.19%
Mean					5.92%	5.88%	5.83%	5.79%	5.74%	5.70%	5.66%	5.61%	5.57%	5.52%	5.48%	9.33%
Median					6.19%	6.12%	6.04%	5.97%	5.90%	5.83%	5.76%	5.69%	5.62%	5.55%	5.48%	9.27%

Notes:
[1] Bloomberg Professional as of February 28, 2026
[2] Bloomberg Professional 90-day average as of February 28, 2026
[3] Attachment PAC/404
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Attachment PAC/410
[15] 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 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Alliant Energy Corporation	LNT	$2.14	$65.00	6.00%	5.95%	5.91%	5.86%	5.81%	5.76%	5.72%	5.67%	5.62%	5.57%	5.53%	5.48%	9.21%
Ameren Corporation	AEE	$2.84	$100.87	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	8.84%
American Electric Power Company, Inc.	AEP	$3.80	$113.15	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	9.49%
Avista Corporation	AVA	$1.97	$37.81	6.01%	5.97%	5.92%	5.87%	5.82%	5.77%	5.72%	5.67%	5.62%	5.58%	5.53%	5.48%	11.41%
CMS Energy Corporation	CMS	$2.28	$71.25	7.30%	7.13%	6.97%	6.80%	6.64%	6.47%	6.31%	6.14%	5.98%	5.81%	5.64%	5.48%	9.64%
Dominion Resources, Inc.	D	$2.67	$58.62	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	10.91%
DTE Energy Company	DTE	$4.66	$135.02	4.50%	4.59%	4.68%	4.77%	4.86%	4.94%	5.03%	5.12%	5.21%	5.30%	5.39%	5.48%	8.79%
Entergy Corporation	ETR	$2.56	$91.12	3.00%	3.23%	3.45%	3.68%	3.90%	4.13%	4.35%	4.58%	4.80%	5.03%	5.25%	5.48%	7.68%
Evergy, Inc.	EVRG	$2.78	$73.39	5.90%	5.86%	5.82%	5.78%	5.75%	5.71%	5.67%	5.63%	5.59%	5.55%	5.52%	5.48%	9.73%
IDACORP, Inc.	IDA	$3.52	$126.39	6.00%	5.95%	5.91%	5.86%	5.81%	5.76%	5.72%	5.67%	5.62%	5.57%	5.53%	5.48%	8.62%
NextEra Energy, Inc.	NEE	$2.49	$78.51	7.06%	6.91%	6.77%	6.63%	6.48%	6.34%	6.20%	6.05%	5.91%	5.76%	5.62%	5.48%	9.50%
OGE Energy Corporation	OGE	$1.70	$44.06	5.80%	5.77%	5.74%	5.71%	5.68%	5.65%	5.62%	5.60%	5.57%	5.54%	5.51%	5.48%	9.76%
Pinnacle West Capital Corporation	PNW	$3.64	$89.23	3.60%	3.77%	3.94%	4.11%	4.28%	4.45%	4.62%	4.80%	4.97%	5.14%	5.31%	5.48%	9.04%
PPL Corporation	PPL	$1.09	$35.61	7.30%	7.13%	6.97%	6.80%	6.64%	6.47%	6.31%	6.14%	5.98%	5.81%	5.64%	5.48%	9.46%
Southern Company	SO	$2.96	$90.39	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	9.39%
Xcel Energy Inc.	XEL	$2.28	$74.75	7.00%	6.86%	6.72%	6.58%	6.45%	6.31%	6.17%	6.03%	5.89%	5.75%	5.62%	5.48%	9.32%
Mean					5.92%	5.88%	5.83%	5.79%	5.74%	5.70%	5.66%	5.61%	5.57%	5.52%	5.48%	9.42%
Median					6.19%	6.12%	6.04%	5.97%	5.90%	5.83%	5.76%	5.69%	5.62%	5.55%	5.48%	9.43%

Notes:
[1] Bloomberg Professional as of February 28, 2026
[2] Bloomberg Professional 180-day average as of February 28, 2026
[3] Attachment PAC/404
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Attachment PAC/410
[15] Equals internal rate of return of cash flows for Year 0 through Year 200

AVERAGE FIRST STAGE GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: **30** **DAYS**

Company		1 Annualized Dividend	2 Stock Price	3 First Stage Gwth Rate	4 Year 11	5 Year 12	6 Year 13	7 Year 14	8 Year 15	9 Year 16	10 Year 17	11 Year 18	12 Year 19	13 Year 20	14 Third Stage Growth Rate	15 ROE
Alliant Energy Corporation	LNT	$2.14	$68.21	6.96%	6.83%	6.69%	6.56%	6.42%	6.29%	6.15%	6.02%	5.88%	5.75%	5.61%	5.48%	9.42%
Ameren Corporation	AEE	$2.84	$106.45	7.96%	7.74%	7.51%	7.29%	7.06%	6.83%	6.61%	6.38%	6.16%	5.93%	5.70%	5.48%	9.22%
American Electric Power Company, Inc.	AEP	$3.80	$123.02	7.17%	7.01%	6.86%	6.71%	6.55%	6.40%	6.25%	6.09%	5.94%	5.79%	5.63%	5.48%	9.44%
Avista Corporation	AVA	$1.97	$40.90	6.54%	6.44%	6.35%	6.25%	6.15%	6.06%	5.96%	5.86%	5.77%	5.67%	5.57%	5.48%	11.24%
CMS Energy Corporation	CMS	$2.28	$73.13	7.78%	7.57%	7.36%	7.15%	6.94%	6.73%	6.52%	6.32%	6.11%	5.90%	5.69%	5.48%	9.74%
Dominion Resources, Inc.	D	$2.67	$61.93	7.90%	7.68%	7.46%	7.24%	7.02%	6.80%	6.58%	6.36%	6.14%	5.92%	5.70%	5.48%	11.36%
DTE Energy Company	DTE	$4.66	$139.12	6.21%	6.14%	6.08%	6.01%	5.94%	5.88%	5.81%	5.74%	5.68%	5.61%	5.54%	5.48%	9.36%
Entergy Corporation	ETR	$2.56	$99.07	8.57%	8.29%	8.01%	7.72%	7.44%	7.16%	6.88%	6.60%	6.32%	6.04%	5.76%	5.48%	9.34%
Evergy, Inc.	EVRG	$2.78	$78.68	6.87%	6.75%	6.62%	6.49%	6.37%	6.24%	6.11%	5.99%	5.86%	5.73%	5.60%	5.48%	9.87%
IDACORP, Inc.	IDA	$3.52	$136.59	7.45%	7.27%	7.09%	6.91%	6.73%	6.55%	6.37%	6.19%	6.01%	5.84%	5.66%	5.48%	8.90%
NextEra Energy, Inc.	NEE	$2.49	$88.71	7.72%	7.51%	7.31%	7.11%	6.90%	6.70%	6.50%	6.29%	6.09%	5.89%	5.68%	5.48%	9.31%
OGE Energy Corporation	OGE	$1.70	$45.14	6.24%	6.17%	6.10%	6.03%	5.97%	5.90%	5.83%	5.76%	5.69%	5.62%	5.55%	5.48%	9.86%
Pinnacle West Capital Corporation	PNW	$3.64	$95.21	5.42%	5.43%	5.43%	5.44%	5.44%	5.45%	5.45%	5.46%	5.46%	5.47%	5.47%	5.48%	9.56%
PPL Corporation	PPL	$1.09	$36.74	7.45%	7.27%	7.09%	6.91%	6.73%	6.56%	6.38%	6.20%	6.02%	5.84%	5.66%	5.48%	9.40%
Southern Company	SO	$2.96	$90.70	7.02%	6.88%	6.74%	6.60%	6.46%	6.32%	6.18%	6.04%	5.90%	5.76%	5.62%	5.48%	9.60%
Xcel Energy Inc.	XEL	$2.28	$78.21	8.20%	7.95%	7.70%	7.46%	7.21%	6.96%	6.71%	6.47%	6.22%	5.97%	5.73%	5.48%	9.65%
Mean					7.06%	6.90%	6.74%	6.58%	6.43%	6.27%	6.11%	5.95%	5.79%	5.64%	5.48%	9.70%
Median					7.14%	6.97%	6.81%	6.64%	6.48%	6.31%	6.14%	5.98%	5.81%	5.64%	5.48%	9.50%

Notes:
[1] Bloomberg Professional as of February 28, 2026
[2] Bloomberg Professional 30-day average as of February 28, 2026
[3] Attachment PAC/404
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Attachment PAC/410
[15] 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	11	12	13	14	15
Company		Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Alliant Energy Corporation	LNT	$2.14	$66.75	6.96%	6.83%	6.69%	6.56%	6.42%	6.29%	6.15%	6.02%	5.88%	5.75%	5.61%	5.48%	9.50%
Ameren Corporation	AEE	$2.84	$103.11	7.96%	7.74%	7.51%	7.29%	7.06%	6.83%	6.61%	6.38%	6.16%	5.93%	5.70%	5.48%	9.33%
American Electric Power Company, Inc.	AEP	$3.80	$118.97	7.17%	7.01%	6.86%	6.71%	6.55%	6.40%	6.25%	6.09%	5.94%	5.79%	5.63%	5.48%	9.57%
Avista Corporation	AVA	$1.97	$39.47	6.54%	6.44%	6.35%	6.25%	6.15%	6.06%	5.96%	5.86%	5.77%	5.67%	5.57%	5.48%	11.45%
CMS Energy Corporation	CMS	$2.28	$72.03	7.78%	7.57%	7.36%	7.15%	6.94%	6.73%	6.52%	6.32%	6.11%	5.90%	5.69%	5.48%	9.80%
Dominion Resources, Inc.	D	$2.67	$59.86	7.90%	7.68%	7.46%	7.24%	7.02%	6.80%	6.58%	6.36%	6.14%	5.92%	5.70%	5.48%	11.56%
DTE Energy Company	DTE	$4.66	$135.08	6.21%	6.14%	6.08%	6.01%	5.94%	5.88%	5.81%	5.74%	5.68%	5.61%	5.54%	5.48%	9.47%
Entergy Corporation	ETR	$2.56	$95.42	8.57%	8.29%	8.01%	7.72%	7.44%	7.16%	6.88%	6.60%	6.32%	6.04%	5.76%	5.48%	9.48%
Evergy, Inc.	EVRG	$2.78	$76.13	6.87%	6.75%	6.62%	6.49%	6.37%	6.24%	6.11%	5.99%	5.86%	5.73%	5.60%	5.48%	10.01%
IDACORP, Inc.	IDA	$3.52	$130.81	7.45%	7.27%	7.09%	6.91%	6.73%	6.55%	6.37%	6.19%	6.01%	5.84%	5.66%	5.48%	9.04%
NextEra Energy, Inc.	NEE	$2.49	$84.04	7.72%	7.51%	7.31%	7.11%	6.90%	6.70%	6.50%	6.29%	6.09%	5.89%	5.68%	5.48%	9.51%
OGE Energy Corporation	OGE	$1.70	$44.13	6.24%	6.17%	6.10%	6.03%	5.97%	5.90%	5.83%	5.76%	5.69%	5.62%	5.55%	5.48%	9.96%
Pinnacle West Capital Corporation	PNW	$3.64	$90.46	5.42%	5.43%	5.43%	5.44%	5.44%	5.45%	5.45%	5.46%	5.46%	5.47%	5.47%	5.48%	9.78%
PPL Corporation	PPL	$1.09	$35.88	7.45%	7.27%	7.09%	6.91%	6.73%	6.56%	6.38%	6.20%	6.02%	5.84%	5.66%	5.48%	9.50%
Southern Company	SO	$2.96	$89.25	7.02%	6.88%	6.74%	6.60%	6.46%	6.32%	6.18%	6.04%	5.90%	5.76%	5.62%	5.48%	9.66%
Xcel Energy Inc.	XEL	$2.28	$77.58	8.20%	7.95%	7.70%	7.46%	7.21%	6.96%	6.71%	6.47%	6.22%	5.97%	5.73%	5.48%	9.68%
Mean					7.06%	6.90%	6.74%	6.58%	6.43%	6.27%	6.11%	5.95%	5.79%	5.64%	5.48%	9.83%
Median					7.14%	6.97%	6.81%	6.64%	6.48%	6.31%	6.14%	5.98%	5.81%	5.64%	5.48%	9.62%

Notes:
[1] Bloomberg Professional as of February 28, 2026
[2] Bloomberg Professional 90-day average as of February 28, 2026
[3] Attachment PAC/404
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Attachment PAC/410
[15] 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	11	12	13	14	15
Company		Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Alliant Energy Corporation	LNT	$2.14	$65.00	6.96%	6.83%	6.69%	6.56%	6.42%	6.29%	6.15%	6.02%	5.88%	5.75%	5.61%	5.48%	9.61%
Ameren Corporation	AEE	$2.84	$100.87	7.96%	7.74%	7.51%	7.29%	7.06%	6.83%	6.61%	6.38%	6.16%	5.93%	5.70%	5.48%	9.41%
American Electric Power Company, Inc.	AEP	$3.80	$113.15	7.17%	7.01%	6.86%	6.71%	6.55%	6.40%	6.25%	6.09%	5.94%	5.79%	5.63%	5.48%	9.78%
Avista Corporation	AVA	$1.97	$37.81	6.54%	6.44%	6.35%	6.25%	6.15%	6.06%	5.96%	5.86%	5.77%	5.67%	5.57%	5.48%	11.71%
CMS Energy Corporation	CMS	$2.28	$71.25	7.78%	7.57%	7.36%	7.15%	6.94%	6.73%	6.52%	6.32%	6.11%	5.90%	5.69%	5.48%	9.85%
Dominion Resources, Inc.	D	$2.67	$58.62	7.90%	7.68%	7.46%	7.24%	7.02%	6.80%	6.58%	6.36%	6.14%	5.92%	5.70%	5.48%	11.68%
DTE Energy Company	DTE	$4.66	$135.02	6.21%	6.14%	6.08%	6.01%	5.94%	5.88%	5.81%	5.74%	5.68%	5.61%	5.54%	5.48%	9.48%
Entergy Corporation	ETR	$2.56	$91.12	8.57%	8.29%	8.01%	7.72%	7.44%	7.16%	6.88%	6.60%	6.32%	6.04%	5.76%	5.48%	9.66%
Evergy, Inc.	EVRG	$2.78	$73.39	6.87%	6.75%	6.62%	6.49%	6.37%	6.24%	6.11%	5.99%	5.86%	5.73%	5.60%	5.48%	10.18%
IDACORP, Inc.	IDA	$3.52	$126.39	7.45%	7.27%	7.09%	6.91%	6.73%	6.55%	6.37%	6.19%	6.01%	5.84%	5.66%	5.48%	9.17%
NextEra Energy, Inc.	NEE	$2.49	$78.51	7.72%	7.51%	7.31%	7.11%	6.90%	6.70%	6.50%	6.29%	6.09%	5.89%	5.68%	5.48%	9.79%
OGE Energy Corporation	OGE	$1.70	$44.06	6.24%	6.17%	6.10%	6.03%	5.97%	5.90%	5.83%	5.76%	5.69%	5.62%	5.55%	5.48%	9.97%
Pinnacle West Capital Corporation	PNW	$3.64	$89.23	5.42%	5.43%	5.43%	5.44%	5.44%	5.45%	5.45%	5.46%	5.46%	5.47%	5.47%	5.48%	9.84%
PPL Corporation	PPL	$1.09	$35.61	7.45%	7.27%	7.09%	6.91%	6.73%	6.56%	6.38%	6.20%	6.02%	5.84%	5.66%	5.48%	9.53%
Southern Company	SO	$2.96	$90.39	7.02%	6.88%	6.74%	6.60%	6.46%	6.32%	6.18%	6.04%	5.90%	5.76%	5.62%	5.48%	9.61%
Xcel Energy Inc.	XEL	$2.28	$74.75	8.20%	7.95%	7.70%	7.46%	7.21%	6.96%	6.71%	6.47%	6.22%	5.97%	5.73%	5.48%	9.83%
Mean					7.06%	6.90%	6.74%	6.58%	6.43%	6.27%	6.11%	5.95%	5.79%	5.64%	5.48%	9.94%
Median					7.14%	6.97%	6.81%	6.64%	6.48%	6.31%	6.14%	5.98%	5.81%	5.64%	5.48%	9.78%

Notes:
[1] Bloomberg Professional as of February 28, 2026
[2] Bloomberg Professional 180-day average as of February 28, 2026
[3] Attachment PAC/404
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Attachment PAC/410
[15] 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: **30** **DAYS**

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Company		Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Alliant Energy Corporation	LNT	$2.14	$68.21	7.69%	7.49%	7.29%	7.09%	6.88%	6.68%	6.48%	6.28%	6.08%	5.88%	5.68%	5.48%	9.73%
Ameren Corporation	AEE	$2.84	$106.45	9.30%	8.95%	8.61%	8.26%	7.91%	7.56%	7.22%	6.87%	6.52%	6.17%	5.83%	5.48%	9.76%
American Electric Power Company, Inc.	AEP	$3.80	$123.02	8.30%	8.05%	7.79%	7.53%	7.28%	7.02%	6.76%	6.51%	6.25%	5.99%	5.73%	5.48%	9.93%
Avista Corporation	AVA	$1.97	$40.90	7.10%	6.95%	6.81%	6.66%	6.51%	6.36%	6.22%	6.07%	5.92%	5.77%	5.63%	5.48%	11.56%
CMS Energy Corporation	CMS	$2.28	$73.13	8.50%	8.23%	7.95%	7.68%	7.40%	7.13%	6.85%	6.58%	6.30%	6.03%	5.75%	5.48%	10.06%
Dominion Resources, Inc.	D	$2.67	$61.93	10.30%	9.86%	9.42%	8.98%	8.55%	8.11%	7.67%	7.23%	6.79%	6.35%	5.92%	5.48%	12.74%
DTE Energy Company	DTE	$4.66	$139.12	7.10%	6.95%	6.81%	6.66%	6.51%	6.36%	6.22%	6.07%	5.92%	5.77%	5.63%	5.48%	9.74%
Entergy Corporation	ETR	$2.56	$99.07	11.50%	10.95%	10.41%	9.86%	9.31%	8.76%	8.22%	7.67%	7.12%	6.57%	6.03%	5.48%	10.62%
Evergy, Inc.	EVRG	$2.78	$78.68	7.50%	7.32%	7.13%	6.95%	6.76%	6.58%	6.40%	6.21%	6.03%	5.85%	5.66%	5.48%	10.15%
IDACORP, Inc.	IDA	$3.52	$136.59	8.34%	8.08%	7.82%	7.56%	7.30%	7.04%	6.78%	6.52%	6.26%	6.00%	5.74%	5.48%	9.24%
NextEra Energy, Inc.	NEE	$2.49	$88.71	8.10%	7.86%	7.62%	7.38%	7.15%	6.91%	6.67%	6.43%	6.19%	5.95%	5.72%	5.48%	9.46%
OGE Energy Corporation	OGE	$1.70	$45.14	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	9.98%
Pinnacle West Capital Corporation	PNW	$3.64	$95.21	7.67%	7.47%	7.27%	7.07%	6.87%	6.67%	6.47%	6.27%	6.08%	5.88%	5.68%	5.48%	10.61%
PPL Corporation	PPL	$1.09	$36.74	7.56%	7.37%	7.18%	6.99%	6.80%	6.61%	6.42%	6.23%	6.05%	5.86%	5.67%	5.48%	9.45%
Southern Company	SO	$2.96	$90.70	7.36%	7.18%	7.01%	6.84%	6.67%	6.50%	6.33%	6.16%	5.99%	5.82%	5.65%	5.48%	9.74%
Xcel Energy Inc.	XEL	$2.28	$78.21	8.90%	8.59%	8.28%	7.97%	7.66%	7.34%	7.03%	6.72%	6.41%	6.10%	5.79%	5.48%	9.95%
Mean					7.98%	7.73%	7.48%	7.23%	6.98%	6.73%	6.48%	6.23%	5.98%	5.73%	5.48%	10.17%
Median					7.67%	7.45%	7.24%	7.02%	6.80%	6.58%	6.36%	6.14%	5.92%	5.70%	5.48%	9.94%

Notes:
[1] Bloomberg Professional as of February 28, 2026
[2] Bloomberg Professional 30-day average as of February 28, 2026
[3] Attachment PAC/404
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Attachment PAC/410
[15] 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	11	12	13	14	15
Company		Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Alliant Energy Corporation	LNT	$2.14	$66.75	7.69%	7.49%	7.29%	7.09%	6.88%	6.68%	6.48%	6.28%	6.08%	5.88%	5.68%	5.48%	9.82%
Ameren Corporation	AEE	$2.84	$103.11	9.30%	8.95%	8.61%	8.26%	7.91%	7.56%	7.22%	6.87%	6.52%	6.17%	5.83%	5.48%	9.89%
American Electric Power Company, Inc.	AEP	$3.80	$118.97	8.30%	8.05%	7.79%	7.53%	7.28%	7.02%	6.76%	6.51%	6.25%	5.99%	5.73%	5.48%	10.08%
Avista Corporation	AVA	$1.97	$39.47	7.10%	6.95%	6.81%	6.66%	6.51%	6.36%	6.22%	6.07%	5.92%	5.77%	5.63%	5.48%	11.77%
CMS Energy Corporation	CMS	$2.28	$72.03	8.50%	8.23%	7.95%	7.68%	7.40%	7.13%	6.85%	6.58%	6.30%	6.03%	5.75%	5.48%	10.13%
Dominion Resources, Inc.	D	$2.67	$59.86	10.30%	9.86%	9.42%	8.98%	8.55%	8.11%	7.67%	7.23%	6.79%	6.35%	5.92%	5.48%	12.97%
DTE Energy Company	DTE	$4.66	$135.08	7.10%	6.95%	6.81%	6.66%	6.51%	6.36%	6.22%	6.07%	5.92%	5.77%	5.63%	5.48%	9.86%
Entergy Corporation	ETR	$2.56	$95.42	11.50%	10.95%	10.41%	9.86%	9.31%	8.76%	8.22%	7.67%	7.12%	6.57%	6.03%	5.48%	10.79%
Evergy, Inc.	EVRG	$2.78	$76.13	7.50%	7.32%	7.13%	6.95%	6.76%	6.58%	6.40%	6.21%	6.03%	5.85%	5.66%	5.48%	10.30%
IDACORP, Inc.	IDA	$3.52	$130.81	8.34%	8.08%	7.82%	7.56%	7.30%	7.04%	6.78%	6.52%	6.26%	6.00%	5.74%	5.48%	9.40%
NextEra Energy, Inc.	NEE	$2.49	$84.04	8.10%	7.86%	7.62%	7.38%	7.15%	6.91%	6.67%	6.43%	6.19%	5.95%	5.72%	5.48%	9.68%
OGE Energy Corporation	OGE	$1.70	$44.13	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	10.08%
Pinnacle West Capital Corporation	PNW	$3.64	$90.46	7.67%	7.47%	7.27%	7.07%	6.87%	6.67%	6.47%	6.27%	6.08%	5.88%	5.68%	5.48%	10.87%
PPL Corporation	PPL	$1.09	$35.88	7.56%	7.37%	7.18%	6.99%	6.80%	6.61%	6.42%	6.23%	6.05%	5.86%	5.67%	5.48%	9.54%
Southern Company	SO	$2.96	$89.25	7.36%	7.18%	7.01%	6.84%	6.67%	6.50%	6.33%	6.16%	5.99%	5.82%	5.65%	5.48%	9.81%
Xcel Energy Inc.	XEL	$2.28	$77.58	8.90%	8.59%	8.28%	7.97%	7.66%	7.34%	7.03%	6.72%	6.41%	6.10%	5.79%	5.48%	9.99%
Mean					7.98%	7.73%	7.48%	7.23%	6.98%	6.73%	6.48%	6.23%	5.98%	5.73%	5.48%	10.31%
Median					7.67%	7.45%	7.24%	7.02%	6.80%	6.58%	6.36%	6.14%	5.92%	5.70%	5.48%	10.03%

Notes:
[1] Bloomberg Professional as of February 28, 2026
[2] Bloomberg Professional 90-day average as of February 28, 2026
[3] Attachment PAC/404
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Attachment PAC/410
[15] 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	11	12	13	14	15
Company		Annualized Dividend	Stock Price	First Stage Gwth Rate	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Third Stage Growth Rate	ROE
Alliant Energy Corporation	LNT	$2.14	$65.00	7.69%	7.49%	7.29%	7.09%	6.88%	6.68%	6.48%	6.28%	6.08%	5.88%	5.68%	5.48%	9.93%
Ameren Corporation	AEE	$2.84	$100.87	9.30%	8.95%	8.61%	8.26%	7.91%	7.56%	7.22%	6.87%	6.52%	6.17%	5.83%	5.48%	9.98%
American Electric Power Company, Inc.	AEP	$3.80	$113.15	8.30%	8.05%	7.79%	7.53%	7.28%	7.02%	6.76%	6.51%	6.25%	5.99%	5.73%	5.48%	10.30%
Avista Corporation	AVA	$1.97	$37.81	7.10%	6.95%	6.81%	6.66%	6.51%	6.36%	6.22%	6.07%	5.92%	5.77%	5.63%	5.48%	12.04%
CMS Energy Corporation	CMS	$2.28	$71.25	8.50%	8.23%	7.95%	7.68%	7.40%	7.13%	6.85%	6.58%	6.30%	6.03%	5.75%	5.48%	10.17%
Dominion Resources, Inc.	D	$2.67	$58.62	10.30%	9.86%	9.42%	8.98%	8.55%	8.11%	7.67%	7.23%	6.79%	6.35%	5.92%	5.48%	13.11%
DTE Energy Company	DTE	$4.66	$135.02	7.10%	6.95%	6.81%	6.66%	6.51%	6.36%	6.22%	6.07%	5.92%	5.77%	5.63%	5.48%	9.87%
Entergy Corporation	ETR	$2.56	$91.12	11.50%	10.95%	10.41%	9.86%	9.31%	8.76%	8.22%	7.67%	7.12%	6.57%	6.03%	5.48%	11.01%
Evergy, Inc.	EVRG	$2.78	$73.39	7.50%	7.32%	7.13%	6.95%	6.76%	6.58%	6.40%	6.21%	6.03%	5.85%	5.66%	5.48%	10.48%
IDACORP, Inc.	IDA	$3.52	$126.39	8.34%	8.08%	7.82%	7.56%	7.30%	7.04%	6.78%	6.52%	6.26%	6.00%	5.74%	5.48%	9.53%
NextEra Energy, Inc.	NEE	$2.49	$78.51	8.10%	7.86%	7.62%	7.38%	7.15%	6.91%	6.67%	6.43%	6.19%	5.95%	5.72%	5.48%	9.96%
OGE Energy Corporation	OGE	$1.70	$44.06	6.50%	6.41%	6.31%	6.22%	6.13%	6.04%	5.94%	5.85%	5.76%	5.66%	5.57%	5.48%	10.09%
Pinnacle West Capital Corporation	PNW	$3.64	$89.23	7.67%	7.47%	7.27%	7.07%	6.87%	6.67%	6.47%	6.27%	6.08%	5.88%	5.68%	5.48%	10.94%
PPL Corporation	PPL	$1.09	$35.61	7.56%	7.37%	7.18%	6.99%	6.80%	6.61%	6.42%	6.23%	6.05%	5.86%	5.67%	5.48%	9.57%
Southern Company	SO	$2.96	$90.39	7.36%	7.18%	7.01%	6.84%	6.67%	6.50%	6.33%	6.16%	5.99%	5.82%	5.65%	5.48%	9.76%
Xcel Energy Inc.	XEL	$2.28	$74.75	8.90%	8.59%	8.28%	7.97%	7.66%	7.34%	7.03%	6.72%	6.41%	6.10%	5.79%	5.48%	10.15%
Mean					7.98%	7.73%	7.48%	7.23%	6.98%	6.73%	6.48%	6.23%	5.98%	5.73%	5.48%	10.43%
Median					7.67%	7.45%	7.24%	7.02%	6.80%	6.58%	6.36%	6.14%	5.92%	5.70%	5.48%	10.12%

Notes:
[1] Bloomberg Professional as of February 28, 2026
[2] Bloomberg Professional 180-day average as of February 28, 2026
[3] Attachment PAC/404
[4] Equals [3] + ([14] − [3]) / 11
[5] Equals [4] + ([14] − [3]) / 11
[6] Equals [5] + ([14] − [3]) / 11
[7] Equals [6] + ([14] − [3]) / 11
[8] Equals [7] + ([14] − [3]) / 11
[9] Equals [8] + ([14] − [3]) / 11
[10] Equals [9] + ([14] − [3]) / 11
[11] Equals [10] + ([14] − [3]) / 11
[12] Equals [11] + ([14] − [3]) / 11
[13] Equals [12] + ([14] − [3]) / 11
[14] Attachment PAC/410
[15] Equals internal rate of return of cash flows for Year 0 through Year 200

Docket No. UE 470
Exhibit PAC/410
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Gross Domestic Product Growth

May 2026

CALCULATION OF LONG-TERM GROWTH RATE FOR MULTI-STAGE DCF

Historical GDP Growth		
Real GDP ($ Billions) [1]	1929	$ 1,191.1
	2025	$ 23,864.5
Compound Annual Growth Rate		**3.17%**
Inflation Forecast		
Consumer Price Index (YoY % Change) [2]	2032-2036	2.30%
Consumer Price Index (All-Urban) [3]	2035	3.86
	2050	5.37
Compound Annual Growth Rate		2.23%
GDP Chain-type Price Index (2012=1.000) [3]	2035	1.66
	2050	2.30
Compound Annual Growth Rate		2.18%
Average Inflation Forecast		**2.24%**
Long-Term GDP Growth Rate		**5.48%**

Notes:

[1] Bureau of Economic Analysis, September 25, 2025

[2] Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 14

[3] Energy Information Administration, Annual Energy Outlook 2025 at Table 20, April 15, 2025

Docket No. UE 470
Exhibit PAC/411
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Capital Expenditures Analysis

May 2026

PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT
($ Millions)

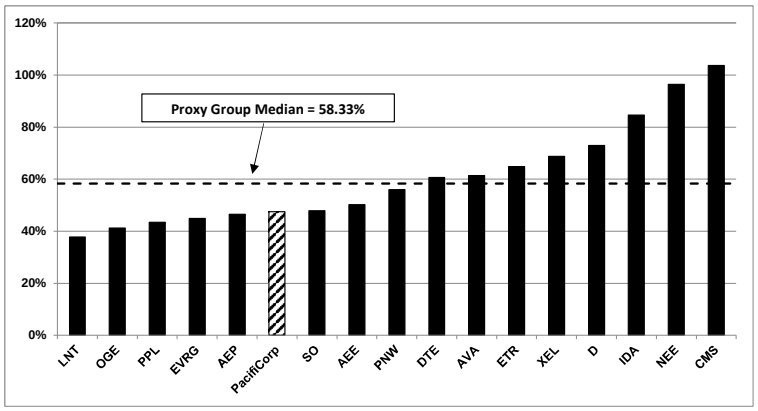
		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2024	2026	2027	2028	2029	2030	2026-2030 Cap. Ex. / 2024 Net Plant
Alliant Energy Corporation	LNT							
Capital Spending per Share			$5.60	5.50	$5.40	$5.40	$5.40	
Common Shares Outstanding			257.50	258.25	259.00	259.00	259.00	
Capital Expenditures			$1,442.0	$1,420.4	$1,398.6	$1,398.6	$1,398.6	37.7%
Net Plant		$18,701.0						
Ameren Corporation	AEE							
Capital Spending per Share			$12.85	$12.93	$13.00	$13.00	$13.00	
Common Shares Outstanding			275.00	280.00	285.00	285.00	285.00	
Capital Expenditures			$3,533.8	$3,619.0	$3,705.0	$3,705.0	$3,705.0	50.2%
Net Plant		$36,376.0						
American Electric Power Company, Inc.	AEP							
Capital Spending per Share			$14.10	$14.05	$14.00	$14.00	$14.00	
Common Shares Outstanding			540.00	545.00	550.00	550.00	550.00	
Capital Expenditures			$7,614.0	$7,657.3	$7,700.0	$7,700.0	$7,700.0	46.6%
Net Plant		$82,416.0						
Avista Corporation	AVA							
Capital Spending per Share			$7.00	$8.25	$9.50	$9.50	$9.50	
Common Shares Outstanding			83.00	84.00	85.00	85.00	85.00	
Capital Expenditures			$581.0	$693.0	$807.5	$807.5	$807.5	61.4%
Net Plant		$6,020.0						
CMS Energy Corporation	CMS							
Capital Spending per Share			$16.40	$18.00	$19.60	$19.60	$19.60	
Common Shares Outstanding			305.00	305.50	306.00	306.00	306.00	
Capital Expenditures			$5,002.0	$5,499.0	$5,997.6	$5,997.6	$5,997.6	103.8%
Net Plant		$27,461.0						
Dominion Resources, Inc.	D							
Capital Spending per Share			$12.75	$10.50	$10.75	$11.00	$11.00	
Common Shares Outstanding			870.00	865.00	897.50	930.00	930.00	
Capital Expenditures			$11,092.5	$9,082.5	$9,648.1	$10,230.0	$10,230.0	73.0%
Net Plant		$68,862.0						
DTE Energy Company	DTE							
Capital Spending per Share			$17.95	$18.23	$18.50	$18.50	$18.50	
Common Shares Outstanding			205.50	205.75	206.00	206.00	206.00	
Capital Expenditures			$3,688.7	$3,749.8	$3,811.0	$3,811.0	$3,811.0	60.7%
Net Plant		$31,081.0						
Entergy Corporation	ETR							
Capital Spending per Share			$12.50	$13.25	$14.00	$14.00	$14.00	
Common Shares Outstanding			440.00	450.00	460.00	460.00	460.00	
Capital Expenditures			$5,500.0	$5,962.5	$6,440.0	$6,440.0	$6,440.0	64.9%
Net Plant		$47,423.0						
Evergy, Inc.	EVRG							
Capital Spending per Share			$9.35	$9.43	$9.50	$9.50	$9.50	
Common Shares Outstanding			230.00	230.00	230.00	230.00	230.00	
Capital Expenditures			$2,150.5	$2,167.8	$2,185.0	$2,185.0	$2,185.0	44.9%
Net Plant		$24,200.0						
IDACORP, Inc.	IDA							
Capital Spending per Share			$19.75	$19.75	$19.75	$19.75	$19.75	
Common Shares Outstanding			55.50	55.75	56.00	56.00	56.00	
Capital Expenditures			$1,096.1	$1,101.1	$1,106.0	$1,106.0	$1,106.0	84.6%
Net Plant		$6,517.3						

PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2024	2026	2027	2028	2029	2030	2026-2030 Cap. Ex. / 2024 Net Plant
NextEra Energy, Inc.	NEE							
Capital Spending per Share			$12.00	$12.25	$12.38	$12.50	$12.50	
Common Shares Outstanding			2110.00	2135.00	2177.50	2220.00	2220.00	
Capital Expenditures			$25,320.0	$26,153.8	$26,946.6	$27,750.0	$27,750.0	96.4%
Net Plant		$138,852.0						
OGE Energy Corporation	OGE							
Capital Spending per Share			$4.75	$4.75	$4.75	$4.75	$4.75	
Common Shares Outstanding			200.20	200.20	200.20	200.20	200.20	
Capital Expenditures			$951.0	$951.0	$951.0	$951.0	$951.0	41.2%
Net Plant		$11,538.0						
Pinnacle West Capital Corporation	PNW							
Capital Spending per Share			$17.00	$17.25	$17.50	$17.50	$17.50	
Common Shares Outstanding			121.00	123.00	125.00	125.00	125.00	
Capital Expenditures			$2,057.0	$2,121.8	$2,187.5	$2,187.5	$2,187.5	55.9%
Net Plant		$19,198.0						
PPL Corporation	PPL							
Capital Spending per Share			$3.75	$3.85	$3.93	$4.00	$4.00	
Common Shares Outstanding			737.50	$737.60	737.80	738.00	738.00	
Capital Expenditures			$2,765.6	$2,839.8	$2,895.9	$2,952.0	$2,952.0	43.5%
Net Plant		$33,149.0						
Southern Company	SO							
Capital Spending per Share			$8.70	$8.65	$8.58	$8.50	$8.50	
Common Shares Outstanding			1110.00	$1,115.00	1117.50	1120.00	1120.00	
Capital Expenditures			$9,657.0	$9,644.8	$9,582.6	$9,520.0	$9,520.0	47.9%
Net Plant		$100,028.0						
Xcel Energy Inc.	XEL							
Capital Spending per Share			$13.50	$13.25	$13.00	$13.00	$13.00	
Common Shares Outstanding			593.50	$596.75	600.00	600.00	600.00	
Capital Expenditures			$8,012.3	$7,906.9	$7,800.0	$7,800.0	$7,800.0	68.7%
Net Plant		$57,198.0						
PacifiCorp	PacifiCorp							
Capital Expenditures [8]			3,003	2,615	2,486	2,479	2,537	47.5%
Net Plant [9]		$27,638						
							Total CapEx	$13,119

Notes:
[1] - [6] Value Line dated November 7, December 5, 2025, January 16, 2026.
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Company Provided Data
[9] PacifiCorp - 2024 FERC Form 1

PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT



Projected CAPEX / 2024 Net Plant

Rank	Company		Percent
1	Alliant Energy Corporation	LNT	37.7%
2	OGE Energy Corporation	OGE	41.2%
3	PPL Corporation	PPL	43.5%
4	Evergy, Inc.	EVRG	44.9%
5	American Electric Power Company, Inc.	AEP	46.6%
6	PacifiCorp	PacifiCorp	47.5%
7	Southern Company	SO	47.9%
8	Ameren Corporation	AEE	50.2%
9	Pinnacle West Capital Corporation	PNW	55.9%
10	DTE Energy Company	DTE	60.7%
11	Avista Corporation	AVA	61.4%
12	Entergy Corporation	ETR	64.9%
13	Xcel Energy Inc.	XEL	68.7%
14	Dominion Resources, Inc.	D	73.0%
15	IDACORP, Inc.	IDA	84.6%
16	NextEra Energy, Inc.	NEE	96.4%
17	CMS Energy Corporation	CMS	103.8%
	Proxy Group Median		58.33%

Notes:
Attachment PAC/411, pp. 1-2 col. [7]

Docket No. UE 470
Exhibit PAC/412
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Regulatory Risk Analysis

May 2026

COMPARISON OF COMPANY AND PROXY GROUP COMPANIES
REGULATORY RISK ASSESSMENT

Company	Operating Subsidiary	State	Utility Type	[1] Test Year Convention	[2] Revenue Stabilization: Revenue Decoupling	[3] Revenue Stabilization: Formula-Based Rates	[4] Revenue Stabilization: Straight Fixed Variable Rate Design	[5] Revenue Stabilization: Overall Revenue Stabilization	[6] Capital Cost Recovery	[7] Fuel/Purchased Power Cost Recovery
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Fully Forecast	No	No	No	No	No	Yes
	Interstate Power & Light Co.	Iowa	Gas	Fully Forecast	No	No	No	No	No	Yes
	Wisconsin Power & Light Co.	Wisconsin	Electric	Fully Forecast	No	No	No	No	No	Yes
	Wisconsin Power & Light Co.	Wisconsin	Gas	Fully Forecast	No	No	No	No	No	Yes
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	Fully Forecast	Yes	No	No	Yes	Yes	N/A
	Ameren Illinois Co.	Illinois	Gas	Fully Forecast	Yes	No	No	Yes	Yes	Yes
	Union Electric Co.	Missouri	Electric	Historical	Yes	No	No	Yes	Yes	Yes w/ Sharing
	Union Electric Co.	Missouri	Gas	Historical	Yes	No	No	Yes	Yes	Yes
American Electric Power Company, Inc.	Southwestern Electric Power Co.	Arkansas	Electric	Historical	No	Yes	No	Yes	Yes	Yes
	Indiana Michigan Power Co.	Indiana	Electric	Fully Forecast	Yes	No	No	Yes	Yes	Yes
	Kentucky Power Co.	Kentucky	Electric	Historical	Yes	No	No	Yes	Yes	Yes
	Southwestern Electric Power Co.	Louisiana	Electric	Historical	No	Yes	No	Yes	No	Yes
	Indiana Michigan Power Co.	Michigan	Electric	Fully Forecast	Yes	No	No	Yes	Yes	Yes
	Ohio Power Co.	Ohio	Electric	Partially Forecast	No	No	No	No	Yes	N/A
	Public Service Co. of Oklahoma	Oklahoma	Electric	Historical	Yes	No	No	Yes	Yes	Yes
	Kingsport Power Co.	Tennessee	Electric	Historical	No	No	No	No	No	Yes
	AEP Texas	Texas	Electric	Historical	No	No	No	No	Yes	N/A
	Southwestern Electric Power Co.	Texas	Electric	Historical	No	No	No	No	No	Yes
	Appalachian Power Co.	Virginia	Electric	Historical	No	No	No	No	No	Yes
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	Historical	No	No	No	No	Yes	Yes
Avista Corporation	Alaska Electric Light and Power Co.	Alaska	Electric	Historical	No	No	No	No	No	Yes
	Avista Corp.	Idaho	Electric	Historical	Yes	No	No	Yes	Yes	Yes w/ Sharing
	Avista Corp.	Idaho	Gas	Historical	Yes	No	No	Yes	Yes	Yes
	Avista Corp.	Oregon	Gas	Fully Forecast	Yes	No	No	Yes	No	Yes
	Avista Corp.	Washington	Electric	Historical	Yes	No	No	Yes	Yes	Yes w/ Sharing
	Avista Corp.	Washington	Gas	Historical	Yes	No	No	Yes	Yes	Yes w/ Sharing
CMS Energy Corporation	Consumers Energy Co.	Michigan	Electric	Fully Forecast	No	No	No	No	Yes	Yes
	Consumers Energy Co.	Michigan	Gas	Fully Forecast	Yes	No	No	Yes	Yes	Yes
Dominion Resources, Inc.	Dominion Energy Virginia	North Carolina	Electric	Historical	Yes	No	No	Yes	Yes	Yes
	Dominion Energy South Carolina	South Carolina	Electric	Historical	No	No	No	No	Yes	Yes
	Dominion Energy South Carolina	South Carolina	Gas	Historical	Yes	No	No	Yes	Yes	Yes
	Dominion Energy Virginia	Virginia	Electric	Partially Forecast	No	No	No	No	Yes	Yes
DTE Energy Company	DTE Electric Co.	Michigan	Electric	Fully Forecast	No	No	No	No	Yes	Yes
	DTE Gas Co.	Michigan	Gas	Fully Forecast	Yes	No	No	Yes	Yes	Yes
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Fully Forecast	No	Yes	No	Yes	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Electric	Partially Forecast	No	Yes	No	Yes	Yes	Yes

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
							Revenue Stabilization			
	Entergy New Orleans LLC	Louisiana-NOCC	Gas	Partially Forecast	No	Yes	No	Yes	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Electric	Historical	No	Yes	No	Yes	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Gas	Historical	No	Yes	No	Yes	Yes	Yes
	Entergy Mississippi LLC	Mississippi	Electric	Fully Forecast	No	Yes	No	Yes	Yes	Yes
	Entergy Texas Inc.	Texas	Electric	Fully Forecast	No	No	No	No	Yes	Yes
Evergy, Inc.	Evergy Kansas Central Inc	Kansas	Electric	Historical	Yes	No	No	Yes	Yes	Yes
	Evergy Metro Inc.	Kansas	Electric	Historical	No	No	No	No	Yes	Yes
	Evergy Metro Inc	Missouri	Electric	Historical	Yes	No	No	Yes	Yes	Yes
	Evergy Missouri West Inc.	Missouri	Electric	Historical	Yes	No	No	Yes	Yes	Yes
IDACORP, Inc.	Idaho Power Co.	Idaho	Electric	Partially Forecast	Yes	No	No	Yes	No	Yes w/ Sharing
	Idaho Power Co.	Oregon	Electric	Partially Forecast	No	No	No	No	No	Yes w/ Sharing
NextEra Energy, Inc.	Florida Power & Light Co.	Florida	Electric	Fully Forecast	No	No	No	No	Yes	Yes
OGE Energy Corporation	Oklahoma Gas and Electric Company	Arkansas	Electric	Historical	No	Yes	No	Yes	Yes	Yes
	Oklahoma Gas and Electric Company	Oklahoma	Electric	Historical	Yes	No	No	Yes	Yes	Yes
Pinnacle West Capital Corporation	Arizona Public Service Co.	Arizona	Electric	Historical	Yes	No	No	Yes	Yes	Yes
PPL Corporation	Kentucky Utilities Co.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes	Yes
	Louisville Gas & Electric Co.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	Yes	Yes
	Louisville Gas & Electric Co.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	Yes	Yes
	PPL Electric Utilities Corp.	Pennsylvania	Electric	Fully Forecast	No	No	No	No	Yes	N/A
	Narragansett Electric Co.	Rhode Island	Electric	Historical	Yes	No	No	Yes	Yes	N/A
	Narragansett Electric Co.	Rhode Island	Gas	Historical	Yes	No	No	Yes	Yes	Yes
	Kentucky Utilities Co.	Virginia	Electric	Historical	No	No	No	No	No	Yes
Southern Company	Alabama Power Co.	Alabama	Electric	Fully Forecast	No	Yes	No	Yes	Yes	Yes
	Georgia Power Co.	Georgia	Electric	Fully Forecast	No	No	No	No	Yes	Yes
	Atlanta Gas & Light Co.	Georgia	Gas	Fully Forecast	Yes	Yes	Yes	Yes	Yes	N/A
	Northern Illinois Gas Co.	Illinois	Gas	Fully Forecast	Yes	No	Yes	Yes	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes	Yes
	Chattanooga Gas Co.	Tennessee	Gas	Historical	Yes	Yes	No	Yes	Yes	Yes
	Virginia Natural Gas Inc.	Virginia	Gas	Partially Forecast	Yes	No	Yes	Yes	Yes	Yes
Xcel Energy	Public Service Co. of Colorado	Colorado	Electric	Historical	Yes	No	No	Yes	Yes	Yes
	Public Service Co. of Colorado	Colorado	Gas	Historical	Yes	No	No	Yes	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Gas	Fully Forecast	Yes	No	No	Yes	Yes	Yes
	Southwestern Public Service Co.	New Mexico	Electric	Fully Forecast	No	No	No	No	Yes	Yes
	Northern States Power Co.-Minnesota	North Dakota	Electric	Fully Forecast	No	No	No	No	Yes	Yes
	Northern States Power Co.-Minnesota	North Dakota	Gas	Fully Forecast	No	No	Yes	Yes	No	Yes
	Northern States Power Co.-Minnesota	South Dakota	Electric	Historical	Yes	No	No	Yes	Yes	Yes
	Southwestern Public Service Co.	Texas	Electric	Historical	No	No	No	No	No	Yes
	Northern States Power Co.-Wisconsin	Wisconsin	Electric	Fully Forecast	No	No	No	No	Yes	Yes
	Northern States Power Co.-Wisconsin	Wisconsin	Gas	Fully Forecast	No	No	No	No	Yes	Yes

Proxy Group Totals										Yes	63
				Fully Forecast	33					No	0
				Partially Forecast	7			Yes	49	61	Yes w/ Sharing	6
				Historical	36			No	27	15	N/A	6
				% Forecast	52.6%			% Yes	64.5%	80.3%	Yes / N/A	92.00%
PacifiCorp (Oregon) [8]		Oregon	Electric	Forecasted	No	No	No		No	Yes		Yes w/ Sharing

Notes:
[1] Regulatory Research Associates, effective as of November 28, 2025.
[2] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September, 2025. Operating subsidiaries not covered in this report were excluded from this exhibit. Designated "Yes" if full or partial decouplin
[3] S&P Capital IQ Pro, Alternative Regulation
[4] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September 2025.
[5] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)
[6] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September 2025. Designated "Yes" if noted by S&P as a having a capital tracker to recover either "Traditional generation", "Renewables/Non-traditional generation", "Delivery infrastructure", or "Environmental compliance".
[7] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September, 2025.
[8] Data provided by the Company.

Docket No. UE 470
Exhibit PAC/413
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Regulatory Research Associates Ranking Analysis

May 2026

COMPARISON OF COMPANY AND PROXY GROUP COMPANIES
RRA JURISDICTIONAL RANKINGS

		[1]	[2]
		RRA	
		Rank	Numeric Rank
Alliant Energy Corporation	Iowa	Above Average/3	3
	Wisconsin	Above Average/3	3
Ameren Corporation	Illinois	Average/3	6
	Missouri	Average/2	5
American Electric Power Company, Inc.	Arkansas	Average/1	4
	Indiana	Average/1	4
	Kentucky	Average/2	5
	Louisiana — PSC	Average/2	5
	Michigan	Average/1	4
	Ohio	Average/1	4
	Oklahoma	Average/3	6
	Tennessee	Above Average/3	3
	Texas — PUC	Below Average/1	7
	Virginia	Average/1	4
	West Virginia	Below Average/1	7
Avista Corporation	Alaska	Below Average/1	7
	Idaho	Average/2	5
	Oregon	Average/3	6
	Washington	Average/3	6
CMS Energy Corporation	Michigan	Average/1	4
Dominion Resources, Inc.	North Carolina	Above Average/3	3
	Ohio	Average/1	4
	South Carolina	Average/2	5
	Utah	Average/2	5
	Virginia	Average/1	4
	West Virginia	Below Average/1	7
	Wyoming	Average/2	5
DTE Energy Company	Michigan	Average/1	4
Entergy	Arkansas	Average/1	4
	Louisiana — NOCC	Average/3	6
	Louisiana — PSC	Average/2	5
	Mississippi	Above Average/3	3
	Texas — PUC	Below Average/1	7
Evergy, Inc.	Kansas	Average/3	6
	Missouri	Average/2	5
IDACORP, Inc.	Idaho	Average/2	5
	Oregon	Average/3	6
NextEra Energy, Inc.	Florida	Above Average/2	2
	Texas — PUC	Below Average/1	7
OGE Energy Corporation	Arkansas	Average/1	4
	Oklahoma	Average/3	6
Pinnacle West Capital Corporation	Arizona	Below Average/2	8
PPL Corporation	Kentucky	Average/2	5
	Pennsylvania	Above Average/2	2
	Rhode Island	Average/2	5
	Virginia	Average/1	4
Southern Company	Alabama	Above Average/1	1
	Georgia	Above Average/2	2
	Illinois	Average/3	6
	Mississippi	Above Average/3	3
	Tennessee	Above Average/3	3
	Virginia	Average/1	4
Xcel Energy Inc.	Colorado	Average/1	4
	Minnesota	Average/2	5
	North Dakota	Average/1	4
	New Mexico	Below Average/1	7
	South Dakota	Average/2	5
	Texas — PUC	Below Average/1	7
	Wisconsin	Above Average/3	3
Proxy Group Average		Average/1 - Average/2	4.73
PacifiCorp	Oregon	Average/3	6

Notes
[1] Source: State Regulatory Evaluations, Regulatory Research Associates, as of August 31, 2025.
[2] AA/1= 1, AA/2= 2, AA/3= 3, A/1= 4, A/2= 5, A/3=6, BA/1= 7, BA/2= 8, BA/3= 9

Docket No. UE 470
Exhibit PAC/414
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

S&P Credit Supportiveness Ranking Analysis

May 2026

COMPARISON OF COMPANY AND PROXY GROUP COMPANIES
S&P JURISDICTIONAL RANKINGS

		[1]	[2]
		S&P	
		Rank	Numeric Rank
Alliant Energy Corporation	Iowa	Most credit supportive	1
	Wisconsin	Most credit supportive	1
Ameren Corporation	Illinois	Very credit supportive	3
	Missouri	Highly credit supportive	2
American Electric Power Company, Inc.	Arkansas	Highly credit supportive	2
	Indiana	Highly credit supportive	2
	Kentucky	Most credit supportive	1
	Louisiana — PSC	Highly credit supportive	2
	Michigan	Most credit supportive	1
	Ohio	Very credit supportive	3
	Oklahoma	Very credit supportive	3
	Tennessee	Highly credit supportive	2
	Texas — PUC	Very credit supportive	3
	Virginia	Highly credit supportive	2
	West Virginia	Very credit supportive	3
Avista Corporation	Alaska	More credit supportive	4
	Idaho	Very credit supportive	3
	Oregon	More credit supportive	4
	Washington	Very credit supportive	3
CMS Energy Corporation	Michigan	Most credit supportive	1
Dominion Resources, Inc.	North Carolina	Highly credit supportive	2
	Ohio	Very credit supportive	3
	South Carolina	More credit supportive	4
	Utah	Highly credit supportive	2
	Virginia	Highly credit supportive	2
	West Virginia	Very credit supportive	3
	Wyoming	Very credit supportive	3
DTE Energy Company	Michigan	Most credit supportive	1
Entergy	Arkansas	Highly credit supportive	2
	Louisiana — NOCC	More credit supportive	4
	Louisiana — PSC	Highly credit supportive	2
	Mississippi	Highly credit supportive	2
	Texas — PUC	Very credit supportive	3
Evergy, Inc.	Kansas	Highly credit supportive	2
	Missouri	Highly credit supportive	2
IDACORP, Inc.	Idaho	Very credit supportive	3
	Oregon	More credit supportive	4
NextEra Energy, Inc.	Florida	Most credit supportive	1
	Texas — PUC	Very credit supportive	3
OGE Energy Corporation	Arkansas	Highly credit supportive	2
	Oklahoma	Very credit supportive	3
Pinnacle West Capital Corporation	Arizona	Very credit supportive	3
PPL Corporation	Kentucky	Most credit supportive	1
	Pennsylvania	Highly credit supportive	2
	Rhode Island	Very credit supportive	3
	Virginia	Highly credit supportive	2
Southern Company	Alabama	Most credit supportive	1
	Georgia	Highly credit supportive	2
	Illinois	Very credit supportive	3
	Mississippi	Highly credit supportive	2
	Tennessee	Highly credit supportive	2
	Virginia	Highly credit supportive	2
Xcel Energy Inc.	Colorado	Very credit supportive	3
	Minnesota	Highly credit supportive	2
	North Dakota	Highly credit supportive	2
	New Mexico	Credit Supportive	5
	South Dakota	Very credit supportive	3
	Texas — PUC	Very credit supportive	3
	Wisconsin	Most credit supportive	1
Proxy Group Average		Very Credit Supportive / Highly Credit Supportive	2.39
PacifiCorp	Oregon	More credit supportive	4

Notes
[1] Source: North American Utilities Regulatory Jurisdictions Update: Missouri and Arizona Assessments Revised; Other Notable Developments, Standard and Poor's Ratings Services, May 16, 2025.

[2] Most= 1, Highly= 2, Very= 3, More= 4, Credit Supportive= 5

Docket No. UE 470
Exhibit PAC/415
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Capital Structure Analysis

May 2026

CAPITAL STRUCTURE ANALYSIS - PacifiCorp

Proxy Group Company	Ticker	Most Recent 8 Quarters (2023Q4 - 2025Q3) Common Equity Ratio	Long-Term Debt Ratio	Preferred Equity Ratio	Total Capitalization
Alliant Energy Corporation	LNT	51.99%	48.01%	0.00%	100.00%
Ameren Corporation	AEE	53.29%	46.25%	0.46%	100.00%
American Electric Power Company, Inc.	AEP	48.95%	51.05%	0.00%	100.00%
Avista Corporation	AVA	50.11%	49.89%	0.00%	100.00%
CMS Energy Corporation	CMS	48.24%	51.60%	0.16%	100.00%
Dominion Resources, Inc.	D	54.29%	45.71%	0.00%	100.00%
DTE Energy Company	DTE	49.49%	50.51%	0.00%	100.00%
Entergy Corporation	ETR	50.84%	49.07%	0.09%	100.00%
Evergy, Inc.	EVRG	60.01%	39.99%	0.00%	100.00%
IDACORP, Inc.	IDA	49.11%	50.89%	0.00%	100.00%
NextEra Energy, Inc.	NEE	60.14%	39.86%	0.00%	100.00%
OGE Energy Corporation	OGE	53.29%	46.71%	0.00%	100.00%
Pinnacle West Capital Corporation	PNW	51.52%	48.48%	0.00%	100.00%
PPL Corporation	PPL	56.19%	43.81%	0.00%	100.00%
Southern Company	SO	55.52%	44.48%	0.00%	100.00%
Xcel Energy Inc.	XEL	53.87%	46.13%	0.00%	100.00%
Average		52.93%	47.03%	0.04%	
Median		52.64%	47.36%	0.00%	
Maximum		60.14%	51.60%	0.46%	
Minimum		48.24%	39.86%	0.00%	

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, and long-term debt of the operating subsidiaries.
[2] Operating subsidiaries with data listed as N/A from S&P Capital IQ have been excluded from the analysis.

Docket No. UE 470
Exhibit PAC/500
Witness: Bryce K. Foster
Witness: Jacqueline T. Wetzsteon

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Bryce K. Foster and Jacqueline T. Wetzsteon

May 2026

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ATTACHED EXHIBITS

Confidential Exhibit PAC/501—B&V Route Study Executive Summary
Confidential Exhibit PAC/502—B&V Route Study Detail
Confidential Exhibit PAC/503—Michels Procurement and Construction Services Contract
Confidential Exhibit PAC/504—Michels Design Submittal

I. INTRODUCTION AND QUALIFICATIONS

A. Bryce Foster

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power.

A. My name is Bryce K. Foster. My business address is 825 NE Multnomah St, Suite 1600, Portland, Oregon 97232. I am the Director of Project Delivery, managing the company's Pacific Power Project Management Office and PacifiCorp Communications and Supervisory Control and Data Acquisition Project Management Office.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science in Mechanical Engineering from Oregon Institute of Technology, and a Master of Science in Engineering with an Electrical focus, from University of Portland. I started my career in product testing and failure analysis and transitioned to project management. I have managed projects in engineering, construction, aerospace, wireless communications, public safety communications, and utility projects for over 20 years. Since 2008 I have focused on public necessity projects and have managed power utility projects since 2016. My team consists of 28 project managers, project controllers, and field quality personnel delivering over 300 active projects. I also directly manage several large complex projects, including a project replace and upgrade distribution lines that crossed beneath the Willamette River, and related infrastructure, located between PacifiCorp's Albina Substation and the Albina secondary network in Northwest Portland (Willamette River Crossing Project, or the Project).

B. Jacqueline Wetzsteon

Q. Please state your name, business address, and present position with PacifiCorp.

A. My name is Jacqueline T. Wetzsteon. My business address is 825 NE Multnomah St, Suite 2000, Portland, Oregon 97232. I am a Program Manager for environmental assessment and remediation in PacifiCorp's Environmental Services Department, and manage Pacific Power's portfolio of contingent environmental liabilities.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science in Environmental Science from the Florida Institute of Technology and a Master of Science in Environmental Science and a Master of Public Affairs from Indiana University. I have over 40 years of experience in the areas of environmental investigation and remediation, the divestiture of environmentally challenged properties, the estimation of contingent environmental liabilities, and environmental compliance. As a former employee of the U.S. Environmental Protection Agency, I have a regulatory foundation in both the Federal Resource Conservation and Recovery Act, and the Comprehensive Environmental Response Compensation and Liability Act (CERCLA). With a technical, regulatory and public affairs background, my primary focus is developing and implementing site-specific strategies to achieve project goals under extensive regulatory scrutiny, and with the participation of numerous parties. I oversee industrial projects from their initial environmental investigation through final disposition.

II. SUMMARY AND PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. Our testimony supports PacifiCorp's $194.1 million capital investment for the

Willamette River Crossing Project.

Q. Please summarize your direct testimony.

A. For almost two decades, local, state, and federal agencies and potentially responsible parties have engaged in material and complex efforts to address remediation of the Portland Harbor Superfund Site (PHSS or Site). As a necessary precursor to those remediation efforts, PacifiCorp has successfully completed the replacement and upgrade of distribution infrastructure that crosses the Willamette River within the PHSS.

Our testimony demonstrates that PacifiCorp's investments in the Willamette River Crossing Project were prudent, meet a substantial Oregon need, will facilitate subsequent remediation and revitalization of the Willamette River as part of the PHSS cleanup activities, and provide an immediate benefit to PacifiCorp's Oregon customers. We recommend that the Public Utility Commission of Oregon (Commission) allow PacifiCorp to recover its distribution investments in this project from Oregon customers.

III. PORTLAND HARBOR SUPERFUND SITE

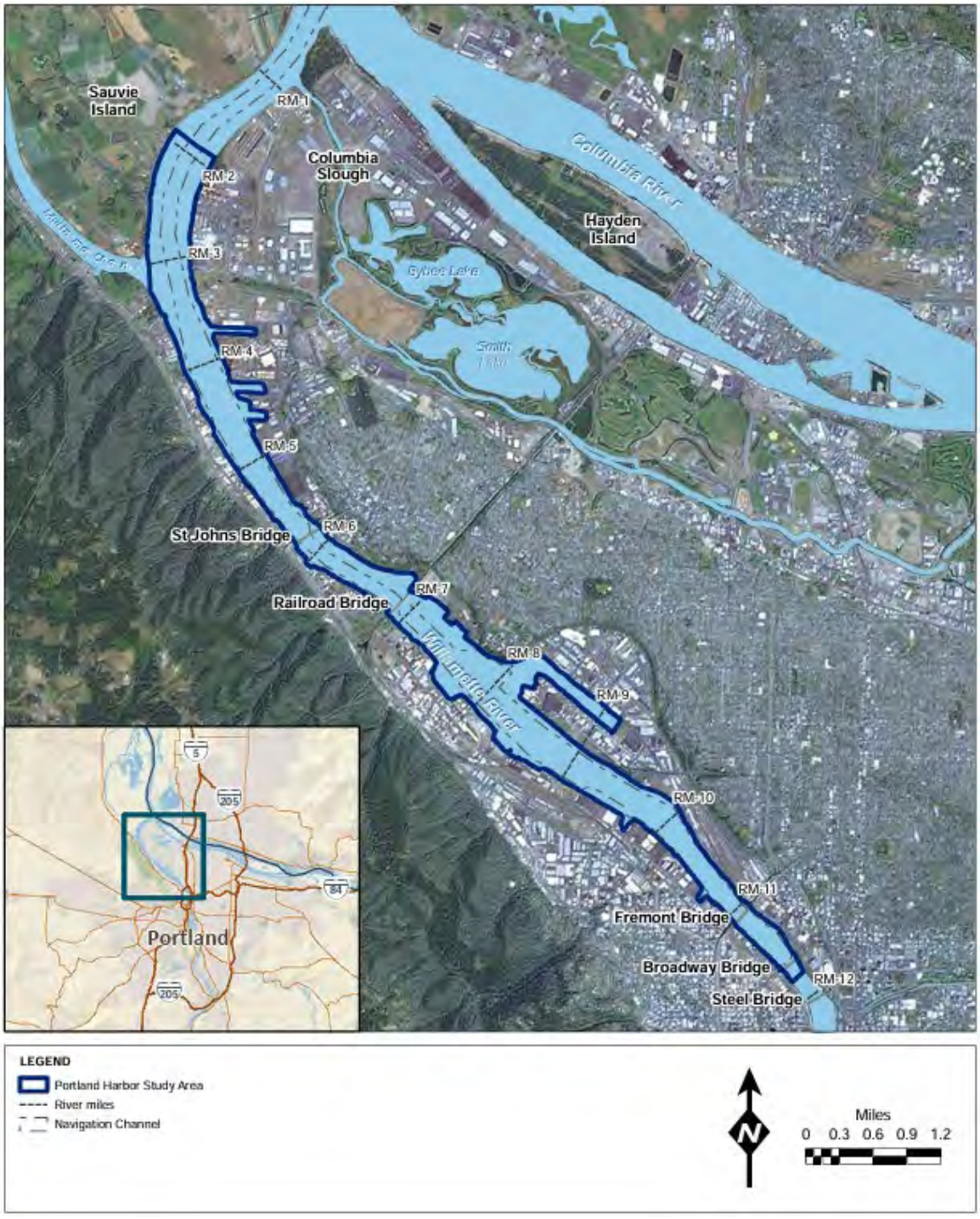
Q. What is the PHSS?

A. The PHSS is an approximate 10-mile section of the Willamette River that, prior to comprehensive federal and state environmental regulations, was the site of significant shipping, industrial, manufacturing, and commercial activity that resulted in the deposition of chemical contaminants in the area. The Site was listed to the federal Superfund National Priorities list (National Priorities List or NPL) in 2000.

As shown in the Figure below, the PHSS is a sediment and riverbank cleanup

site that includes the industrial waterfront and federal navigation channel between downtown Portland at River Mile (RM) 11.8, to almost the confluence of the Willamette and Columbia Rivers at RM 1.9.

Figure 1. Portland Harbor Superfund Site



Q. Why was the Site added to the NPL?

A. The Site was included in the NPL to address "unacceptable human health risks associated with consumption of resident fish and shellfish and exposure to in-river sediments, surface water, and groundwater," as well as "ecological risks to wildlife that consume fish, shellfish, and other biota, as well as bottom-dwelling organisms (benthic invertebrates), fish, and wildlife from exposure to sediment, surface water, and groundwater."[1]

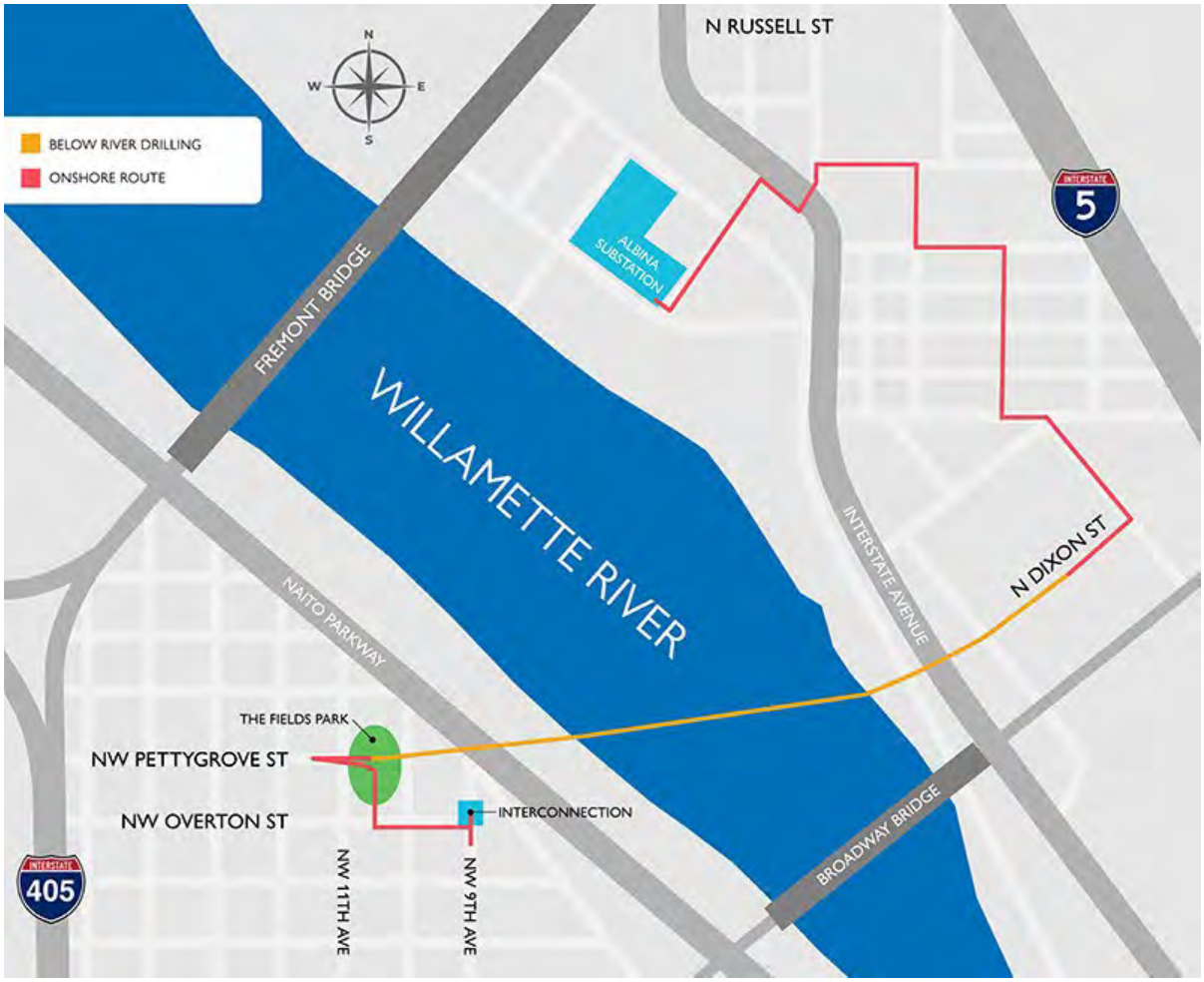
The U.S. Environmental Protection Agency (EPA) is the lead regulatory agency for in-river sediment and most riverbank cleanup, while the Oregon Department of Environmental Quality is the lead regulatory agency for upland source control, including some riverbank cleanup.

Q. What is PacifiCorp's role at the Site?

A. For well over a century, PacifiCorp has provided regulated electrical utility services to Portland customers, including generation, transmission, and distribution services, as well as federally regulated transmission services across the greater Portland area. PacifiCorp's main interest in the PHSS is near River Mile 11E, which is located near facilities currently or formerly owned or operated by PacifiCorp. Figure 2 below shows the PacifiCorp facilities related to River Mile 11E and the Willamette River Crossing Project.

[1] EPA PHSS Record of Decision (ROD) (Jan. 2017) (available here: 100036257.pdf).

Figure 2. Willamette River Crossing Route



Q. Can you provide additional detail on PacifiCorp's infrastructure along River Mile 11E?

A. PacifiCorp currently owns and operates the Albina substation, which is a distribution substation located at River Mile 11, on the east side of the Willamette River between the Fremont and Broadway Bridges. The substation is approximately three acres in size and has been in operation since the 1950s. An earlier substation on adjacent property was in operation from approximately 1913 to 1950.

The distribution system associated with the Albina substation includes two submarine, medium-voltage cable crossings in the Willamette River, which are

referred to as the Centennial Mills cable crossing and the Broadway Bridge cable crossing. The Centennial Mills cable crossing consists of seven distribution cables that are buried under sediment in the Willamette River at a depth of several inches to approximately six feet. The Centennial Mills cable crossing was installed in 1968 and provides electric service to portions of downtown Portland and is a critical part of PacifiCorp's electrical infrastructure. The Centennial Mills cable crossing passes through the River Mile 11E project area.

Q. How are these facilities related to the PHSS?

A. These facilities are located at upland properties in the proximity of the PHSS, and as noted above for the Centennial Mills cable crossing, within the PHSS. Due to the potential release of chemicals of concern from these operations, PacifiCorp received a CERCLA general notice letter in 2011 indicating PacifiCorp had been named a potentially responsible party (PRP) by the EPA for contamination at the PHSS.

Q. What is a PRP?

A. Under CERCLA, a PRP for a federally designated Superfund site may be required to perform response actions deemed necessary by the EPA to protect the public health, welfare, or the environment, and may be responsible for the costs incurred by the government or other parties in responding to any release or threatened release of a hazardous substance.[2]

In EPA's notice to PacifiCorp, EPA identified properties presently and formerly owned or operated by PacifiCorp which may have contributed to contamination at the PHSS. EPA notified PacifiCorp that it could be subject to

[2] *E.g.*, 42 U.S.C. §§ 9606-9607.

liability for a portion of the remediation costs at the PHSS.

Q. Has the EPA designated other potentially responsible parties for the PHSS?

A. Yes. EPA has designated more than 150 potentially responsible parties at the PHSS. A description of how EPA conducts its search for identifying liable parties (e.g., people, businesses, government entities, etc.) that are responsible for contamination at a site can be found on EPA's enforcement website.[3]

Q. What is the EPA's plan for remediating the Site?

A. Detailed information on the history and status of the PHSS can be found on EPA's project website.[4] After many years engaging in the development of a Remedial Investigation, Feasibility Study, and a Proposed Plan, EPA issued its Record of Decision (ROD) for the PHSS in January 2017, which details the EPA's formal remediation plan for the Site.[5] A ROD is a legally binding document, and forms the basis for all remediation or cleanup actions of the PHSS.

EPA's identified remedial strategies are meant to address "all contaminated media and complete exposure pathways that pose unacceptable risk to human health or the environment . . . including sediment, biota, surface water, groundwater, and river banks" at the Site.[6] Depending on location, these remedies include a combination of technologies, including capping, dredging and excavation, in-situ and ex-situ treatment, enhanced natural recovery, monitored natural attenuation, and institutional controls.[7]

[3] Available here: https://www.epa.gov/enforcement/finding-potentially-responsible-parties-prp.
[4] Available here: PORTLAND HARBOR | Superfund Site Profile | Superfund Site Information | US EPA.
[5] Available here: 100036257.pdf.
[6] *Id.* EPA PHSS ROD, § 5, page 9.
[7] *Id.*

Q. Relevant to this proceeding, what remedies did the EPA assign for areas surrounding River Mile 11E?

A. The EPA determined that dredging and excavation were the most appropriate remedies for River Mile 11E.[8]

Q. Why did the EPA determine that dredging and excavation were appropriate?

A. EPA determined that dredging or capping is necessary in areas where sediment contains levels of contamination that exceed the remedial action levels established for the PHSS. In these areas, monitored natural attenuation would not be effective in reducing contaminant levels and ultimately risks.[9]

Q. What steps occur after the EPA issues a ROD?

A. After a ROD is issued, parties engage in remedial design to investigate strategies to implement the EPA's chosen remedies for the site. After the design phase, the EPA moves to remedial actions to implement specific strategies to remediate and cleanup the PHSS as required by the ROD.

Q. Has the EPA directed PRPs to engage in remedial design?

A. Yes. The PHSS has been divided into 17 PRP-led project areas. Each of the 17 project areas are governed by specific EPA agreements and orders for preparing remedial designs for those sites. The EPA is also performing remedial designs at several unassigned areas of the PHSS. PacifiCorp is participating in remedial design at the River Mile 11 East project area (RM11E), which is the furthest upstream area of the Site.

[8] *Id.* § 14.1 and Fig. 31e.
[9] *Id.* § 10.1.2.

Q. Is River Mile 11E a priority area for remediation?

A. While all areas in the PHSS are priority areas for remediation and rehabilitation, the EPA has determined that River Mile 11E should be one of the first areas to be addressed at the PHSS.

To that end, the EPA requested PacifiCorp and other PRPs for River Mile 11E to participate in early action at River Mile 11E. PacifiCorp and five other parties (the River Mile 11E Parties) subsequently entered into an Administrative Settlement Agreement and Order on Consent (Agreed Order) in 2013 to perform early data collection and other pre-remedial studies for River Mile 11E.[10]

PacifiCorp's Centennial Mills cable crossing traverses sediment in the RM11E project area that contains polychlorinated biphenyls (PCBs) at concentrations above the remedial action levels for the PHSS; these sediments are subject to remediation in accordance with the EPA's ROD.

Q. Can you generally describe the results of the environmental investigations performed at the River Mile 11E Project Area?

A. Yes. The RM11E Group initiated sediment investigations at the project area in 2013, and retained Dalton, Olmsted & Fuglevand, an environmental engineering and consulting firm, to evaluate the site and perform remedial design.

This initial work resulted in a 2015 Draft Implementability Study (2015 Study), which ranked the potential impact of the Centennial Mills cable crossing on remedial alternatives in the vicinity of the cable crossing as high, due to issues from

[10] *Id.* § 2.3, at 5 (the parties signed an amended Agreed Order in 2018 to conduct full remedial design for the RM11E project area). PRPs include PacifiCorp, CalPortland (Glacier NW), Cargill, the City of Portland, DIL Trust, and Paramount Global (formerly Westinghouse), referred to collectively as the River Mile 11E Group.

capping and dredging in the area.[11] The 2015 Study concluded that a large no-dig zone, as well as the use of other non-removal measures such as capping or other passive technologies, would be necessary within the caution zone of the submarine crossing.[12] They also noted that conventional capping in navigation areas may not comply with standard navigation clearance requirements in the vicinity of cable crossing.

Q. How did this 2015 Study inform the EPA's evaluation of the site?

A. In the ROD, EPA stated that it is necessary to prevent damage, destabilization, and other adverse impacts to utilities, such as cable crossings, during remedial construction, which may include "working around [public utilities and infrastructure] or in some cases relocating such features."[13]

Consistent with this position, EPA directed the RM11E Group to determine the feasibility of relocating the cable crossing in their comments on the 2015 Study.[14] This was due to the EPA's concerns about the recommendation for a "no dig zone" in the area of the cable crossing, and the possibility of capping extending into the navigation channel where a remedial capping strategy was not preferred. EPA also stated that alternative remedial treatments near the cables should be evaluated due to the potential for recontamination associated with any material left in place adjacent to

[11] RM11E Draft Implementability Study Report, July 31, 2015, page 3-28 (available here: https://semspub.epa.gov/src/document/10/500013838).
[12] *Id.* at 9-5.
[13] EPA PHSS ROD, § 2.21.2 ("During remedial design, site-specific surveys will be conducted to identify public utilities and infrastructure in order to account for these features in the remedial design, which may mean working around them or in some cases relocating such features. Parties planning and/or performing the cleanup will need to coordinate with landowners on details of infrastructure protection, or alternately, details of infrastructure relocation where necessary. Any proposed changes or disturbance to utilities or access of utilities will be coordinated with the City of Portland and others.").
[14] EPA Letter to Jackie Wetzsteon on behalf of the RM11E Group, at 6 (May 14, 2017).

the cables.

Q. After receiving the EPA's feedback, what did the RM11E Group's further study of the area conclude?

A. The RM11E Group moved forward with a subsequent Basis of Design report in 2019 (2019 Design Report), which evaluated feasible remedial technologies at RM11E in conformance with the PHSS ROD, and identified site-specific remedial approaches.[15] This report concluded that dredging in the vicinity of the electrical cable crossing was not possible because of safety restrictions and cable integrity concerns,[16] and similarly, that capping over the cables was not possible because of impacts to cable integrity from increased load and stress potentially leading to failure of the cables.[17] The 2019 Design Report concluded that "active remediation at and near the submarine electrical cable crossing would be possible only if the cable crossing were first removed from service."[18]

Q. How did this 2019 Design Report inform the EPA's evaluation of the site?

A. On December 3, 2019, EPA approved the 2019 Design Report and requested the submittal of a remedial design work plan within 120 days from the date of the approval letter.[19]

Q. Has the RM11E Group engaged in further remedial investigations?

A. Yes. In its June 2023 Preferred Alternatives Report, the RM11E Group concluded that sediment dredging was the single preferred remedial alternative to address

[15] Available here: https://semspub.epa.gov/src/document/10/100191451.
[16] *Id.* § 5.2.3.
[17] *Id.* § 5.2.3.
[18] *Id.* § 6.1.7.
[19] EPA Letter to Jackie Wetzsteon on behalf of the RM11E Group (Dec. 3, 2019).

concentrations of PCBs in sediment at concentrations exceeding remedial action levels while also minimizing the potential for recontamination. The RM11E Group is currently in the process of preparing the 60 percent design report for submittal to EPA in the spring and fall of 2026. After receiving comments from EPA, the RM11E Group will proceed with producing a 95 percent design and 100 percent design.

Q. What steps does PacifiCorp anticipate after submitting this design report to the EPA?

A. In addition to participating in the preparation of the remedial design for the RM11E project area, PacifiCorp is concurrently participating in a voluntary allocation of liability for the PHSS. PacifiCorp is also participating in Consent Decree negotiations with EPA and other PRPs. Upon completion of the mediated allocation of liability and the finalization of a Consent Decree with EPA, PacifiCorp will determine its role in the performance of remedial action at RM11E.

Q. Are parties currently obligated by EPA to engage in remedial action?

A. No. As outlined above, prior to initiating remediation at the PHSS, complex issues of party liability and cost responsibility must be resolved. EPA has initiated formal negotiations with PRPs, including PacifiCorp, to implement remedial actions at PHSS.

Q. Are the PHSS PRPs proactively addressing these issues?

A. Yes. PacifiCorp, along with approximately 100 of the more than 150 PRPs and with the encouragement of EPA, is engaged in a voluntary effort to allocate liability and costs associated with the entire PHSS, including the River Mile 11E area.

The objective of the allocation process is to develop, without resorting to

litigation, a full and fair allocation among PRPs that can form the basis of a good faith offer to EPA to conduct cleanup of the PHSS, as well as provide the basis for settlements of related liabilities. In conjunction with the remedial design work currently ongoing at River Mile 11E, this voluntary allocation and mediation process will enable PacifiCorp to minimize its allocated share of liability through engagement with EPA to effectuate a reasonable cleanup plan and provide a venue for meaningful input on the allocation and settlement of liability among PRPs.

Q. What is the current status of these discussions?

A. The group has engaged third-party experts, or allocators, to assist in the allocation process. PacifiCorp expects these allocators will issue a confidential allocation report in 2026 that will outline percentages of liability by project area. PacifiCorp will then have the opportunity to comment on the report. After review of party comments, the allocators are expected to issue a revised confidential allocation report. In parallel with review and comment on the allocation report, the allocation parties will begin a mediation process with the objective of identifying terms under which they would be able to settle claims amongst themselves, and settle cleanup liabilities with EPA.

Q. Do you have any current estimate of PacifiCorp's expected costs or liability associated with the PHSS?

A. We have no estimate or opinion on PacifiCorp's expected costs or liability associated with the PHSS at this time.

Q. Given this allocation process, do you have any estimates for when remedial actions may begin?

A. Remediation can only begin after complex liability and cost issues for the PHSS are

resolved between the PRPs, and after completing negotiations with EPA for a Consent Decree for the entire site.

IV. PROJECT OVERVIEW

Q. Can you provide a general overview of the project?

A. In recognition of EPA's 2017 ROD, and after evaluating numerous studies, remedial alternatives, and electrical distribution system strategies, PacifiCorp determined in 2018 that it was necessary to remove, replace, and upgrade the Centennial Mills cable crossing. The following sections discuss the Project, construction, and customer benefits that are expected to result from the project.

A. Pre-Construction Activities

Q. What pre-construction activities needed to occur for the Project?

A. Given the EPA's decision that dredging and excavation of River Mile 11E were the most appropriate remedies for the area, and the design engineers' determination that the existing Centennial Mills cable crossing would impede remediation efforts, PacifiCorp needed to determine whether, and when, to remove, replace, and upgrade the distribution infrastructure along River Mile 11E. This involved the investigation of several distribution system strategies.

Q. What distribution strategies did PacifiCorp investigate?

A. PacifiCorp studied several dozen underground, overhead, and bridge-mounted solutions to replace the submarine conductors in the river, and establish a new connection between the company's Albina Substation and the duct bank located under NW 9th Street. The route study process attempted to identify the most direct route that could be constructed, while also avoiding condemnation proceedings.

Q. Were overhead strategies permitted or feasible?

A. No. After several discussions with the City of Portland, the City notified PacifiCorp that overhead routes were not permitted across the Willamette River. This was due to city ordinances that generally prohibit overhead river distribution line crossings in open space greenway corridors, especially along the city's multi-decadal efforts to revitalize and establish a greenway corridor along the Willamette River.[20]

Q. Were bridge-mounted solutions permitted or feasible?

A. No. Most of the bridges in the Portland area are drawbridges, which preclude the mounting of distribution cables when the bridge is raised to allow for water traffic to pass below. As a result, only the Freemont Bridge (Interstate 405), a steel tied-arch bridge located North and West of the Willamette River Crossing, provided a potential bridge-mounted option for the cable crossing.

After review with the Oregon Department of Transportation, the Department notified PacifiCorp that the Freemont Bridge was not a viable option, given the need to install numerous conductors on or in the bridge, outage constraints for maintenance, and engineering concerns from the additional weight that would need to be added to the bridge.

As a result, the only viable path to replace and upgrade the Willamette River Crossing Project infrastructure was to use horizontal directional drilling (HDD) to

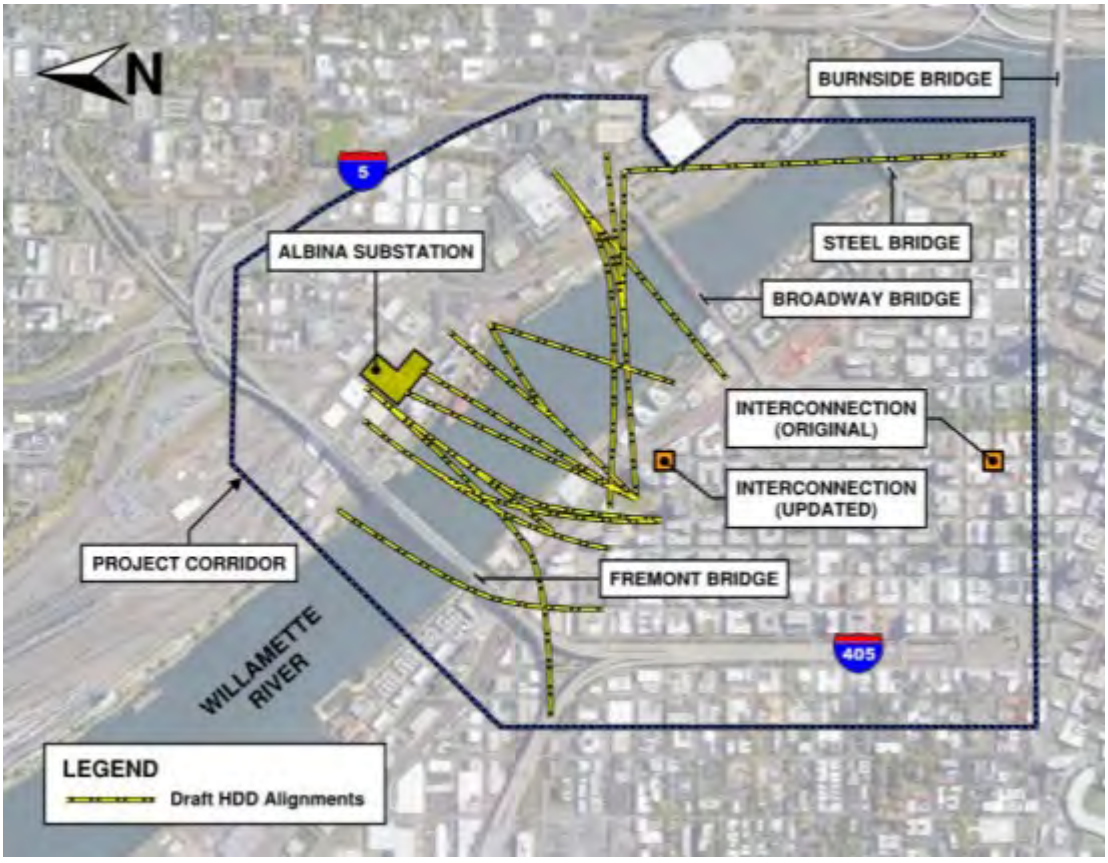
[20] *E.g.*, Willamette Greenway Plan, as Amended by Ordinance No. 190241, at 4-5; *Id.* at Maps 2 and 3 (available here: RIV_WRGI_Recommended_as-ammended_1220_lr.PDF) (indicating that the Willamette River crossing project would have resulted in overhead lines in the City's open space zoning designations, and in the River General Greenway/River Overlay Zone, areas where the City attempts to allow only "uses and development that are consistent with the base zoning that allow for public use and enjoyment of the waterfront, and enhance the river's natural and scenic qualities").

install a new cable crossing deep beneath the contaminated bed of the Willamette River.

Q. What undergrounding strategies did PacifiCorp investigate?

A. PacifiCorp relied on in-house and third-party experts to investigate potential routes to determine what route could be the most feasible. The results of these studies focused on a project corridor generally spanning from the Fremont to Burnside Bridges, and as noted in Figure 3, PacifiCorp initially investigated 18 different routes and related onshore interconnections.[21]

Figure 3. Initial Willamette River Crossing Route Alternatives



After initial review, 13 alternatives were removed from further consideration.

[21] Confidential Exhibit PAC/501—B&V Route Study Executive Summary, at 4, Figure 1-2 (Nov. 9, 2020).

This is because installing a new duct bank under the river required a location where the line could arrive onshore without unduly interfering with sea walls, piles, or surface obstructions. To construct a 3,300-foot HDD duct and conductor, several clear blocks need to line up with the installation path. These constraints restricted the project to only 6 possible routes, largely due to the surface restriction of clear blocks. For example, the 13 eliminated alternatives each presented significant construction or operational conflicts. Some would have required routing beneath significant structures or buildings that would increase complexity and costs, others would conflict with existing footing structures or railyard infrastructure, while others conflicted with Portland sewer infrastructure.[22]

The six remaining potential underground routes for the Willamette River Crossing Project are detailed in Figure 4 below.[23]

[22] *E.g.*, Confidential Exhibit PAC/502—B&V Route Study Detail, § 1.1.2 (Nov. 9, 2020).
[23] *Id.* § 3.0, Figure 3-1.

Figure 4. Shortlisted Willamette River Crossing Route Alternatives

Q. How did PacifiCorp investigate the remaining six alternative routes?

A. PacifiCorp engaged in further feasibility studies to determine which of the remaining six alternative routes presented the lowest risks and highest ability to construct the project for the company. This involved analyzing both underground and aboveground criteria.

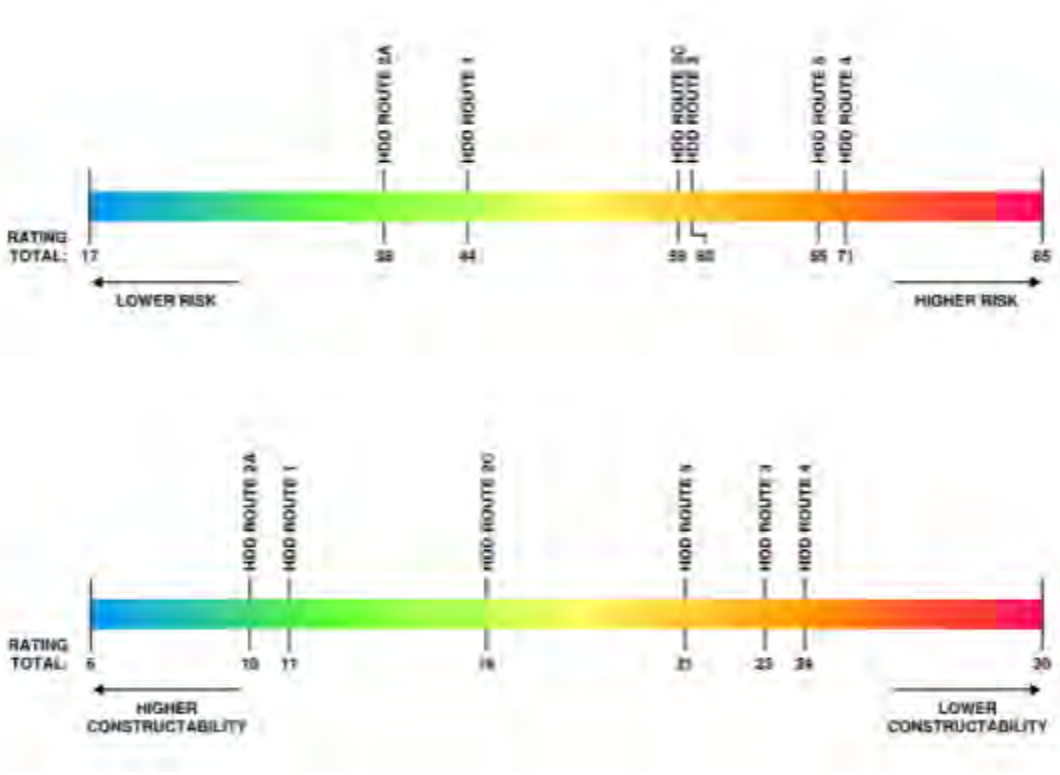
Q. What underground criteria did PacifiCorp analyze?

A. PacifiCorp analyzed both risk and constructability criteria for the underground portion of the Project. Risk criteria included: drill path length, horizontal drill path geometry, vertical geometry, curve radii, compound curvature, drill intersect compatibility, drill rig sites, casing staging, casing pullback, bore hole diameters, conductor casing compatibility, geology, hydrofracture, structure and underground

utility conflicts, rail conflicts, environmental impacts, and real estate.[24] Construction factors that were analyzed included: rig side, pipe side (casing side), conductor casings, drill intersects, bore holes, and drill path geometries.[25]

Each factor was included in a feasibility matrix, to determine the relevant route risks and constructability of alternative routes.[26] As indicated in Figure 5, this analysis indicated that, at least for underground issues, Route 2A presented the optimum balance between risk and constructability issues.[27]

Figure 5. Willamette River Crossing Alternative Underground Route Risk and Constructability Results



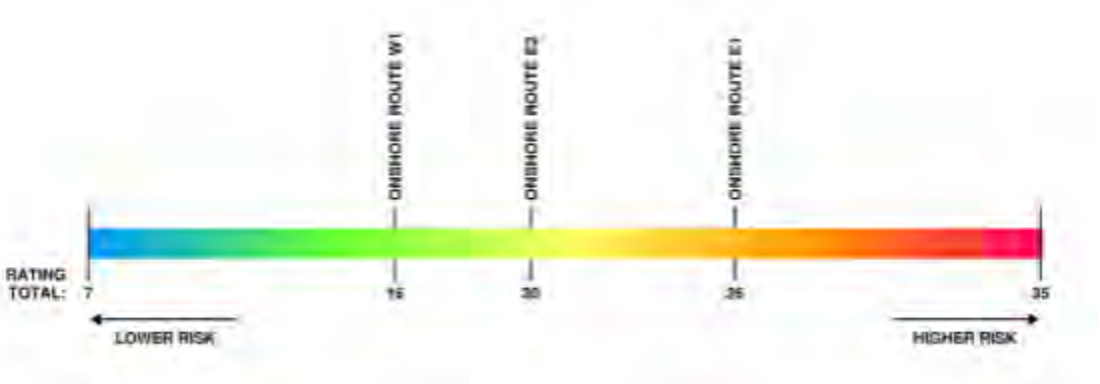
[24] *Id.* §§ 2.1.1-2.1.17 (Nov. 9, 2020).
[25] *Id.* §§ 2.2.1-2.2.6.
[26] *Id.* §§ 3.1-3.8.
[27] *Id.* § 3.7, at Figures 3-12 and 3-13.

Q. What above-ground criteria were analyzed?

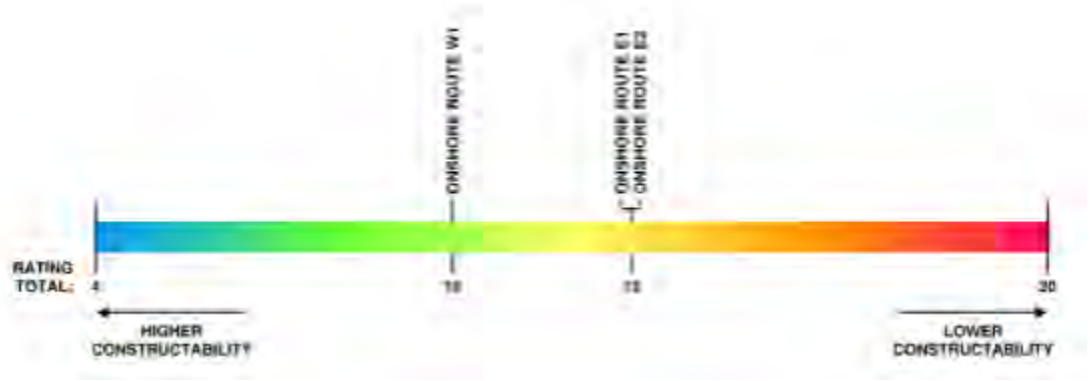
A. PacifiCorp analyzed both route risk and constructability criteria. Route risk criteria included: route length; structure, underground utilities, and urban feature conflicts; rail conflicts; construction conflicts; environmental impacts; real estate; serviceability.[28] Constructability criteria included: natural and manmade surficial obstacles; structure and underground utility conflicts; subsurface conditions; and real estate.[29]

Each factor was included in a feasibility matrix, to determine the relevant route risks and constructability of alternative routes.[30] As indicated in Figure 6, this analysis indicated that for above ground issues, Onshore Route W1 presented the optimum balance between risk and constructability issues.[31]

Figure 6. Willamette River Crossing Alternative Onshore Route Risk and Constructability Results



[28] *Id.* §§ 4.1.1-4.1.7.
[29] *Id.* §§ 4.2.1-4.2.4.
[30] *Id.* §§ 5.1-5.5.
[31] *Id.* § 5.4, Figures 5-5 and 5-6.

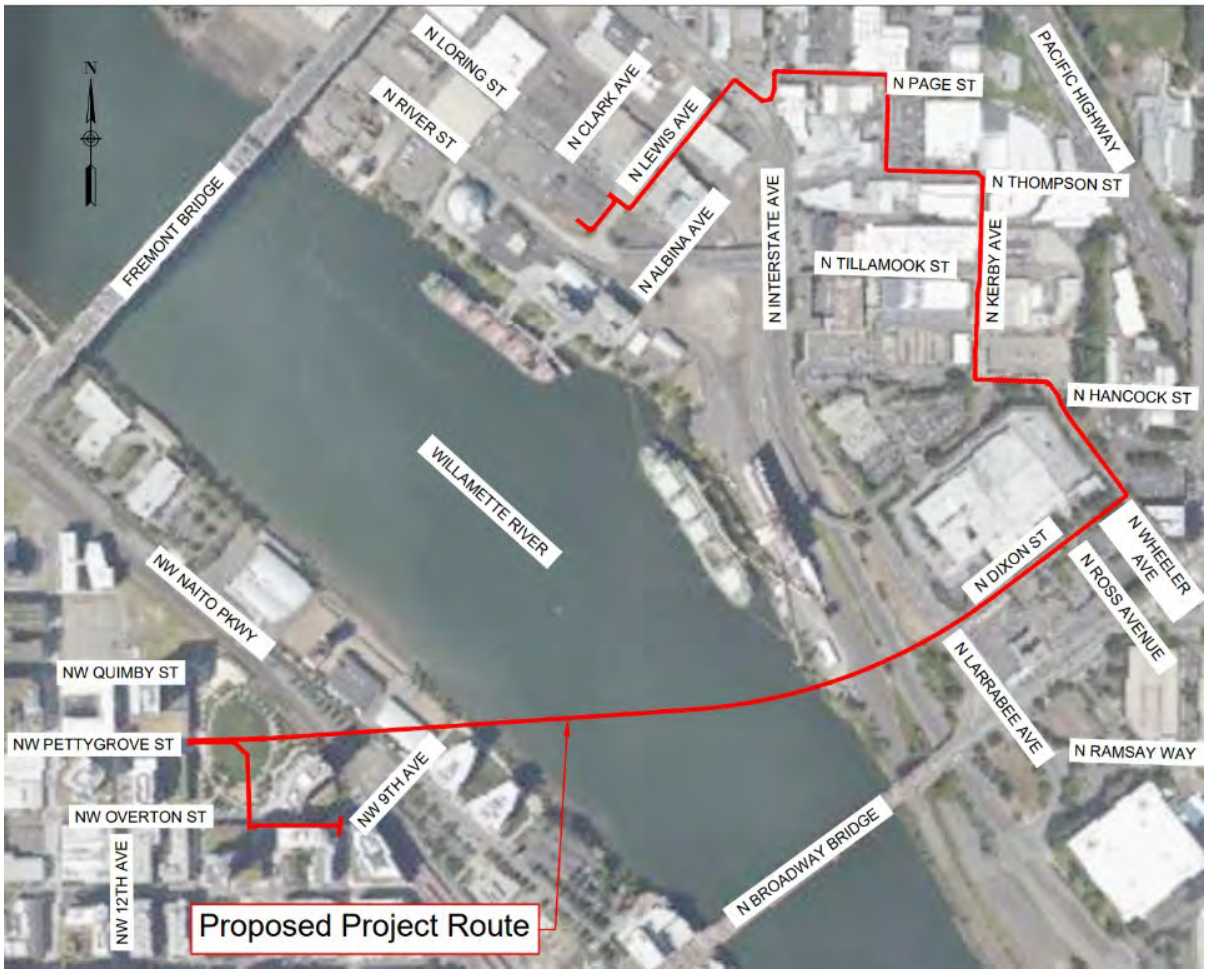


Q. Given these underground and onshore feasibility studies, what route did PacifiCorp ultimately determine was the most appropriate solution for customers?

A. For underground routing, PacifiCorp concluded that Underground Route 2A was the most appropriate solution for customers. However after further investigation of Onshore Route W1, PacifiCorp determined that the route was not preferred, because it would have required PacifiCorp to secure several rights of ways from private and public entities, and the costs to procure these easements or ROWs, as well as the time to do so, exceeded the benefits that Route W1 would otherwise provide.

As a result, PacifiCorp concluded that Underground Route 2A, and Onshore Route 2C that stretched from Fields Park on the west side of the river and to N Dixon Street on the east side of the river, were the optimal routes for the Project. While the selected onshore route did not present the overall lowest risk or highest constructability scores, after discussions with the City of Portland's route permitting and planning department, this route was the most feasible.

Figure 7: Final Route approved by City of Portland



Q. What activities remained after PacifiCorp finalized the route for the line?

A. Given the large HDD installation and complexities of constructing duct banks under the city streets and Willamette River, PacifiCorp determined that it would be prudent to subcontract various aspects of the projects to third-party engineering, design, and construction companies. PacifiCorp issued a request for proposals for the project, seeking qualified engineering, procurement, and construct bids.

As a result of the request for proposals process, the project was awarded to the lowest competitive bidder, Michels Pacific Energy. Michels Pacific Energy partnered with AECOM for engineering and Michels Trenchless for the HDD installation.

Q. Did PacifiCorp's contract with Michels Pacific Energy involve any conditions to minimize risk for Oregon customers, ensure timely construction, and contain costs?

A. Yes. PacifiCorp's contract with Michels involved significant terms and conditions to minimize risk for Oregon customers, ensure timely construction, and contain costs.

For example, the contract included over 39 contractor responsibilities;[32] retained PacifiCorp's right to reject any and all work performed by Michels Pacific Energy if it did not adequately perform any of these obligations;[33] provided for delay damages in the event construction timelines were to be reasonably achieved;[34] as well as required Michels Pacific Energy to agree to material assumption of risk, loss, or damage provisions,[35] and indemnification requirements.[36]

Q. Did PacifiCorp exercise any of these remedies due to Michels Pacific Energy lack of performance?

A. No. Putting aside reasonable adjustments to the scope of the project, timeline, and costs, PacifiCorp has not had to exercise any remedies regarding Michels Pacific Energy's performance under the contract. Despite the complexity of the Project, it was completed within budget, and on time.

Q. Why did PacifiCorp determine to move forward with the Project in 2018?

A. At the time the company made the decision to move forward with the project, it was anticipated to take 3-7 years to complete. If PacifiCorp delayed the project beyond

[32] Confidential Exhibit PAC/503—Michels Procurement and Construction Services Contract, §§ 4.1-4.39 (Mar. 22, 2022).
[33] *Id.* §§ 12.1-12.7.
[34] *Id.* §§ 16.1-16.4
[35] *Id.* §§ 24.1-24.2.
[36] *Id.* §§ 25.1-25.8.

2020, these efforts would impede the remediation of a federal superfund site—again, the EPA's determined remediation strategies for the area involved dredging and excavation of contaminants at River Mile 11E, and these strategies could not occur until the Centennial Mills crossing was removed, which in turn could not occur until the Willamette River Crossing was constructed at lower depths to avoid dredging and excavation activities.

Q. Absent any potential federal superfund obligations, would PacifiCorp have replaced the Willamette River Crossing beginning around 2018?

A. No. PacifiCorp would not otherwise have decided to upgrade and replace the Willamette River crossing infrastructure at that time. The original design of the crossings included 10 cables in total, 6 for everyday use, and 4 reserved for necessary redundancy in case of failure. As of 2020, 6 cables remained operational, with 2 spare feeders. These cables were split into two crossings, with six conductors at the Centennial Mills crossing, and four conductors at the Broadway Bridge.

Given the surplus feeders, durability of the existing infrastructure, routine maintenance, and expected remaining operational lifespan, PacifiCorp's distribution investment plans did not support the removal and replacement of the Centennial Mills crossing infrastructure.

B. <u>Construction Activities</u>

Q. Can you provide an overview of the Project and related construction activities?

A. The Project required the replacement of PacifiCorp's existing submarine, multi-cable crossing, with two separate 3,000-foot-long encasements buried beneath the Willamette River. Once completed, the HDD installations allow for a new 11.7

kilovolt, 12-circuit, three-phase power connection between PacifiCorp's Albina Substation and Albina secondary network.

The project required four general construction activities: installing and upgrading new underground infrastructure, construction of the western and eastern onshore routes, and removal of the existing underground infrastructure.

Q. What actions were required for the eastern and western onshore routes?

A. The eastern onshore route required the installation of approximately 4,100 feet of new distribution cables and supporting infrastructure (over 3,550 feet of open-trench methods, and 400 feet of trenchless methods). The western onshore route required the installation of approximately 1,100 feet of new distribution cables and supporting infrastructure (over 900 feet of open-trench methods, and 225 of trenchless methods). Given the heavy traffic and population densities in the area, PacifiCorp and Michels Pacific Energy coordinated extensively with the City of Portland to limit unnecessary impacts from construction activities. For example, the majority of construction materials were stored approximately 30 minutes off-site, to reduce overall impacts, and PacifiCorp collaborated materially with private landowners on the west side of the river to limit unnecessary construction impacts.[37]

Q. What actions were required to install the underwater infrastructure?

A Due to the challenging geology of the Willamette River in the Portland area, involving multiple layers of alluvial overburden soils (including sands, gravels, and cobbles) that are particularly challenging for trenchless powerline construction, three steps were necessary to install the two HDD installations.

[37] *E.g.*, Confidential Exhibit PAC/504—Michels Design Submittal, §§ 2.1-2.3, §§ 4.1-4.3.

Q. What was the first step in this process?

A. The first step required installing casings, or the entry and exit locations of the underground installation, on either side of the Willamette River.

The Fields Park casing required hammering a 5-foot diameter steel casing, using the largest pneumatic hammer available on the market, through over 60 feet of human-placed material. After the casing was installed, soil and other material remaining inside the casing was removed.

Michels Pacific Energy then proceeded to install a 4-foot diameter pipe within this 5-foot casing. This was accomplished with a mining machine made specifically for this project, a microtunnel boring machine combine with a pipe thruster, which allowed for the pipe to be installed with greater accuracy, and at greater distances, than angled pile driving. This machine lined the previously mined shaft with a steel casing to provide greater structural integrity as it progressed downward, and eventually reached subsurface bedrock approximately 100 feet below the river bottom, and 200 feet from the entry pit. Once this depth was reached, the mining machine was removed, leaving a 4-foot hollowed out casing.

A similar casing was required for the east side of the river. Though given the more favorable geology, the Dixon casing was a less complex endeavor, and involved only the initial hammering of a 200-foot casing, 42-inch in diameter, to reach an adequate depth for HDD installations to proceed.

Q. What was the second step in the process?

A. Michels Pacific Energy next needed to tunnel beneath the Willamette River to connect the Fields Park and Dixon casings.

To accomplish this endeavor, two ten-inch pilot tunnels were bored from either side of the river. Given the length (over 3,000 feet) and depth (approximately 200 feet below the Willamette River bottom) of the underground tunneling, two of only a handful of HDD machines in North America were capable of performing the work. Once the pilot bores were properly installed and met in the middle, the tunnel was increased to 3 feet in diameter with HDD reamers to allow adequate space for PacifiCorp's distribution infrastructure.

Q. What was the third step?

A. The last step required Michels Pacific Energy to install a duct bank liner within the underground tunnel to prevent damages to PacifiCorp's distribution infrastructure from tunnel collapse. This involved welding 24-inch steel casings, stretched out over 10 city blocks, to be pulled into the tunnel from Fields Park to Dixon Street to create the duct bank liner. These processes were then repeated to create the second crossing under the river.

Q. After both tunnels were finished, what construction activities remained?

A. Once both tunnels were installed, all that remained was to pull the six power and two communications conduits through each of the two casings, for a total of 12 power runs and four communications conduits.

Q. Has PacifiCorp removed the prior Willamette River Crossing infrastructure?

A. No. Given the contaminated sediments and soils that were located above and adjacent to the prior Willamette River Crossing, additional investigation, permitting, and feasibility studies were required to ensure proper removal. PacifiCorp is currently proceeding through permitting processes, and removal is scheduled to begin in 2027,

and conclude likely in 2028.

Q. Did PacifiCorp's actions to implement the Project impact Portland public access?

A. Yes. To construct the river crossing, the project needed to close approximately a third of Fields Park for approximately two years, and close several city blocks and access streets for weeks at a time.

Q. How did PacifiCorp mitigate these impacts?

A. The company developed an initial outreach team who attended frequent community meetings, provided learning sessions, and established several information channels to receive and respond to individual questions (*e.g.*, dedicated telephone messaging, email, and Project website). Once Michels Pacific Energy was contracted for construction of the project, they also participated in community outreach, and ensured that each job site was staffed with a representative who was knowledgeable about the project, and was able to answer questions from the community.

This outreach was praised by the community organizations who thanked PacifiCorp for "doing the right thing" throughout the project even when it was disruptive and impactful to their day-to-day lives.

Q. When does PacifiCorp anticipate concluding construction of the Project?

A. Construction activities were predominantly completed in February 2026, with energization and in-service beginning in May 2026 and continuing through July 2026.

C. Customer Benefits

Q. When the line is in-service, what benefits will Oregon customers receive from the Willamette River Crossing Project?

A. PacifiCorp's Oregon customers will receive several benefits from the project, including completing necessary actions prior to cleanup activities around the PHSS; increased system reinforcement and reliability benefits; and increased interconnection and distribution capacity.

Q. Can you describe how the Project benefits cleanup activities around the PHSS?

A. This Project is a necessary precursor to allow cleanup activities for the Superfund cleanup in the Willamette River to begin. Specifically, the existing submarine cables that connect the east and west side of the river at the Centennial Mills crossing pass through contaminated sediments in the PHSS RM11E project area,and need to be removed to allow sediment cleanup to occur. By removing the Pacific Power conductors located in the contaminated river sediment, the company has created a path forward for initiating the remediation of contaminants in the river.

Q. When do you anticipate remediation activities to begin?

A As noted above, remediation can only begin after complex liability and cost issues for the PHSS are resolved between the PRPs, and after completing negotiations with EPA for a Consent Decree for the entire site.

Q. Can you describe how the Project reinforces PacifiCorp's distribution system?

A. Given the location of the Project, the cables are in continuous operation, and if service was interrupted, power delivery to over 2,000 customers across dozens of blocks of downtown Portland would be interrupted. To provide reliable service to the

Downtown Portland service area, two service paths are required: one from Lincoln Substation to the south of the service area, and one from across the Willamette River at Albina Substation. To satisfy the removal requirements of the submarine cables in the river, a new underground crossing was needed to maintain system compliance.

To maintain reliable service, new infrastructure needs to be installed and placed into service ahead of removal of the existing conductors. The new infrastructure completely replaces the existing conductor, and adds additional conductors and communications based on the anticipated future growth of 30 percent over the next 50 years to this service area in Portland. A total of 12 new distribution lines are being installed and one new fiber connection, replacing the existing 10 (six in service) lines and no communications lines. The Project also required construction of a new duct bank between the existing Albina Substation, the new river crossing installation, and the existing duct bank under NW 9th Avenue.

Q. As a result, does the project increase interconnection or distribution capacity?

A. Yes. The two new distribution lines and additional communication line increases interconnection and distribution capacity across the Willamette River. This increased capacity will benefit Oregon customers and address the anticipated 30 percent growth expected over the next 50 years in downtown Portland.

V. THIRD-PARTY FUNDS

Q. Has PacifiCorp received any local, state, or federal funds to offset its costs in the Project or its share of remediation efforts?

A. No. PacifiCorp has not received any government funds to offset its costs in the Project.

Q. Does PacifiCorp anticipate receiving any third-party proceeds to offset its costs in the Project or its share of remediation efforts?

A. PacifiCorp is actively seeking partial recovery of its costs in the Project or remediation from two third-party sources.

First, as noted above, PRPs are currently engaged in a voluntary allocation of costs and liabilities associated with clean-up of the PHSS. As the River Mile 11E design engineers have concluded, the removal of the Willamette River Crossing Project was a necessary precursor to allow for parties to engage in the EPA's determined remediation strategy for River Mile 11E (dredging and excavation). Depending on the results of the allocation and mediation process, PacifiCorp could receive a partial credit for PacifiCorp's costs in the Project, to offset PacifiCorp's contribution to eventual remediation efforts for River Mile 11E and PHSS generally. It needs to be stressed, however, that this allocation process would only reduce PacifiCorp's potential Superfund liabilities and related costs.

Second, from at least the 1960s through 1986, PacifiCorp purchased primary and excess layer comprehensive general liability (CGL) policies that potentially provided insurance coverage for liability arising out of third-party property damage due to the release, discharge, or dispersal of contaminants. PacifiCorp has settled with most of its pre-1986 primary insurers, and many excess insurers, releasing those insurers from claims related to environmental damages. Many insurers that issued CGL policies to PacifiCorp during this timeframe are also now insolvent. Due to significant liability at the PHSS, PacifiCorp initiated an insurance cost recovery claim in October 2012 against insurance companies with remaining CGL insurance

coverage and has been working to negotiate settlements with them ever since. Whatever money is collected from these settlements has been and will continue to be used to offset costs incurred by PacifiCorp at PHSS.

Q. Do you have any estimates of the expected proceeds PacifiCorp will receive from these third parties?

A. PacifiCorp does not have an estimate of expected proceeds from the Superfund proceedings. Given the uncertainty around these proceeds, no estimated reductions have been recorded to the Project costs. Should funds be received in the future, an assessment will be made as to whether they relate to the Project or remediation efforts and apply them accordingly.

Regarding insurance claims, to date, PacifiCorp has recovered $1.8 million in insurance proceeds for costs associated with the investigation of contaminated sediment at River Mile 11E. Any additional recovery will depend on the outcome of ongoing and future coverage litigation and/or arbitration. The amount ultimately recoverable will turn on the resolution of multiple disputed coverage issues, and there is no guarantee that PacifiCorp will recover from any of the remaining CGL insurers.

VI. CONCLUSION

Q. What is your joint recommendation?

A. We recommend that the Commission conclude that PacifiCorp's investment in the Willamette River Crossing Project is prudent and in the public interest.

Q. Does this conclude your joint direct testimony?

A. Yes.

REDACTED
Docket No. UE 470
Exhibit PAC/501
Witness: Bryce K. Foster
Witness: Jacqueline T. Wetzsteon

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of
Bryce K. Foster and Jacqueline T. Wetzsteon

B&V Route Study Executive Summary

May 2026

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

REDACTED
Docket No. UE 470
Exhibit PAC/502
Witness: Bryce K. Foster
Witness: Jacqueline T. Wetzsteon

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of
Bryce K. Foster and Jacqueline T. Wetzsteon

B&V Route Study Detail

May 2026

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REDACTED
Docket No. UE 470
Exhibit PAC/503
Witness: Bryce K. Foster
Witness: Jacqueline T. Wetzsteon

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of
Bryce K. Foster and Jacqueline T. Wetzsteon

Michels Procurement and Construction Services Contract

May 2026

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REDACTED
Docket No. UE 470
Exhibit PAC/504
Witness: Bryce K. Foster
Witness: Jacqueline T. Wetzsteon

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

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Exhibit Accompanying Direct Testimony of
Bryce K. Foster and Jacqueline T. Wetzsteon

Michels Design Submittal

May 2026

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REDACTED
Docket No. UE 470
Exhibit PAC/600
Witness: Jayson D. Branch

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Jayson D. Branch

May 2026

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ATTACHED EXHIBITS

Confidential Exhibit PAC/601—PacifiCorp Coal Inventory Policies and Procedures (February 2026)

Confidential Exhibit PAC/602—Coal Inventory Study for PacifiCorp Coal-Fired Power Plants in Wyoming and Utah (December 2025)

Confidential Exhibit PAC/603—Coal Inventory Study for PacifiCorp Coal-Fired Power Plants in Wyoming and Utah (March 2021)

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power.

A. My name is Jayson D. Branch. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Senior Vice President of Power Supply.

Q. Briefly describe your education and professional experience.

A. I graduated from the University of Utah with a Bachelor of Science in Accounting and a Master's Degree in Professional Accounting. I became a Certified Public Accountant in the State of Utah in 2001. From 2005 to 2015, I held a series of finance and accounting related positions of increasing responsibility within PacifiCorp's Thermal and Renewable Energy Generation departments with a focus on capital expenditures, operations and maintenance expenditures, financial planning and analysis, economic analysis, and technical accounting. Between 2015 and 2025, I served as Vice President of Business Optimization and Innovation for PacifiCorp and as the Rocky Mountain Power Division Controller, where I directed business optimization for PacifiCorp and provided oversight of Rocky Mountain Power's financial operations. I currently serve as the Senior Vice President of Power Supply. My present responsibilities encompass oversight of PacifiCorp's thermal and renewable generation, energy supply management, management of mining and coal fuel operations, and environmental policy and compliance.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony on behalf of PacifiCorp before the Public Utility

Commission of Oregon (Commission). I have also provided testimony before the California Public Utilities Commission and the Washington Utilities and Transportation Commission.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I provide an overview of the company's coal fuel stock balance and forecast for the January 2027 to December 2027 period (Test Year), and I support the reasonableness of the coal fuel inventory levels and associated costs in comparison to the 2025 rate case (Base Year).

Q. Please summarize your testimony.

A. In my testimony, I provide an update on recent changes in the coal market and describe how those changes impact the company's coal fuel inventory for the Test Year. I also outline the forecast coal fuel stock levels at the Hunter and Huntington plants (Utah Plants), and the Jim Bridger plant and explain why these coal fuel inventory levels are necessary, reasonable, and prudent.

III. OVERVIEW OF PACIFICORP'S COAL FUEL STOCK INVENTORY

Q. Please explain how PacifiCorp defines and applies the following terms in regulatory filings, such as this rate case.

A. The company provides definitions for the following industry terms:

- **Fuel stock:** All fuel (coal, natural gas, and oil) held in storage for future consumption. The terms "fuel stock" and "coal stock" are often used interchangeably to refer specifically to coal, as coal typically represents over 90 percent of PacifiCorp's fuel stock.

- **Fuel stock balance:** The dollar value of all fuel stock (coal, natural gas, and oil) at generating plants on which a return is calculated.

- **Coal fuel stock:** Coal stored in stockpiles at coal-fired power plants and available for use in power generation. The term "coal fuel stock" may be used interchangeably with "coal fuel inventory," "fuel stock inventory," "coal stockpile," "coal inventory," and "fuel stock."

- **Coal fuel stock balance:** The dollar value of the coal fuel inventory that is included in rate base.

- **Coal fuel inventory forecast:** The projected quantity of coal required to meet the generating needs of a coal-fired power plant.

Q. Please explain how the company calculated the coal fuel stock balance for each plant for the Test Year and whether the company included a coal fuel inventory forecast for calendar year 2027.

A. The company calculates the Test Year fuel stock balance for its coal-fired power plants using a 13-month average from December 2026 to December 2027. This average is based on the terms of existing coal supply agreements (CSAs), unless a plant has an open or uncontracted position. The company included a coal fuel inventory forecast for calendar year 2027 as part of this proceeding.

For uncontracted positions, published forward coal market prices and company forecasts are used to project Test Year amounts in this proceeding. When the forecasted test year for a filing falls after the termination of a CSA, forecast assumptions are based on historical pricing, resource availability, market pricing, inflation, and generation needs.

Forecasted coal fuel stock balances are computed monthly and include calculations for anticipated received coal quantities and forecasted coal consumption based on forecasted coal generation availability and load requirements. The forecasted test period used in ratemaking filings is established under a normalized forecast and in perfect foresight modeled operating conditions. A normalized

forecast refers to an estimate based on average or typical conditions, while perfect foresight modeled operating conditions assume that all future events are known in advance for modeling purposes.

Q. Please provide an overview of major events that have impacted the national coal market since 2022 and how those events continue to impact PacifiCorp.

A. Since 2022, the national coal market has faced a series of changes and disruptions that have had significant and ongoing impacts on coal supply, resulting in sharp price increases and significant volatility. The market price increases were driven by rising coal demand—partly due to high domestic natural gas prices—alongside low inventory levels at both coal mines and coal-fired power plants. Additional pressures included increased international demand for coal exports, supply chain constraints, labor and material shortages, and broader inflation across the economy.

In the western United States, and Utah in particular, the coal market faced additional challenges. A significant event that occurred in September 2022 was the fire at the Lila Canyon mine in Utah. This incident led to the permanent closure of the coal mine, which had supplied approximately 25 percent of Utah's coal production. As a result, PacifiCorp lost access to a significant portion of its coal supply beginning in late 2022 and continuing into early 2024. This sudden reduction in available coal directly contributed to lower coal deliveries to PacifiCorp's Utah coal-fired power plants, specifically the Utah Plants.

Alongside the Lila Canyon mine closure, other operational hurdles persisted in 2022 and 2023. Coal suppliers faced difficult geological and mining conditions, delays in securing federal mining leases, limited availability of trucking and railway

transportation for coal, extended lead times for new mining equipment, and restricted access to financing. Collectively, these factors made it significantly more difficult for coal suppliers to maintain consistent deliveries to PacifiCorp's coal-fired power plants.

As a direct consequence of these coal supply constraints, several suppliers invoked multiple force majeure claims. Between 2022 and 2023, [redacted] These claims reflected extreme stress on suppliers' ability to deliver contracted coal volumes.

Consequently, PacifiCorp was forced to use existing coal stockpiles at its Utah Plants to mitigate supply shortfalls and meet generation requirements. To conserve the limited fuel, the Utah Plants' coal dispatch was reduced from late 2022 through mid-2024. This reduced generation at the Utah Plants meant that the company had to redispatch its other system resources and purchase more electricity from the market, which increased power costs. Additionally, the coal inventory levels at the Utah Plants dropped well below the recommended ranges outlined in PacifiCorp's coal inventory policies and third-party study, in effect at the time, provided as Confidential Exhibit PAC/603.

The Hunter plant coal stockpile, for example, fell to just [redacted] of its storage capacity in 2023—a critically low level. At the Huntington plant, coal deliveries in 2023 and 2024 fell short of the [redacted]-ton contract minimum due to

coal supply issues, and the Rock Garden coal reserve stockpile adjacent to the Huntington plant was reduced to zero in 2023.

Due to Utah's illiquid coal market and insufficient infrastructure for out-of-state rail deliveries to the Utah Plants, PacifiCorp had limited options for alternative coal supply to the Utah Plants. To mitigate future coal supply risks, and after evaluating several alternatives, the company amended its CSAs with Wolverine in February 2024 for both the Hunter plant (Hunter/Wolverine CSA) and the Huntington plant (Huntington/Wolverine CSA), selecting the least-cost, least-risk solution. These CSA amendments secured a long-term coal supply through renewed operations at the Fossil Rock mine, which allowed PacifiCorp to restore coal inventories at the Utah Plants in 2024 and 2025 to levels recommended by company policy and supported by independent studies.[1]

Despite these improvements, PacifiCorp continues to face coal supply challenges in the Utah coal market, including coal market consolidation, lack of sufficient coal transportation (i.e., truck drivers), and reductions in regional coal demand. Following the expiration of the CSAs with Gentry and Bronco in 2025, PacifiCorp currently depends solely on Wolverine for the Utah Plants' coal supply. In addition, the recent closure of regional coal power plants—the North Valmy Generating Station in Nevada and the Intermountain Power Plant in Utah—has changed the coal market dynamics, making the Utah coal market less liquid due to fewer buyers and sellers.

[1] Confidential Exhibit PAC/601—PacifiCorp Coal Inventory Policies and Procedures (Feb. 2026); and Confidential Exhibit PAC/602—Coal Inventory Study for PacifiCorp Coal-Fired Power Plants in Wyoming and Utah (Dec. 2025).

Q. Please provide background on how the company manages its coal stockpiles.

A. PacifiCorp manages coal stockpiles in accordance with its Coal Inventory Policies and Procedures, with the most recent version provided as Confidential Exhibit PAC/601. These guidelines require each coal-fired plant to maintain adequate coal inventory to support both short-term and long-term system generation requirements, considering plant-specific requirements and regional coal supply conditions. Consistent with these policies, PacifiCorp establishes system-level and plant-level inventory target ranges and routinely reviews those targets through internal analyses to ensure compliance with regulatory and generation requirements.

In addition, PacifiCorp has periodically retained independent consulting firms to conduct financial analyses and studies using advanced modeling techniques to assess its current Coal Inventory Policies and Procedures and recommend strategies for achieving prudent coal inventory target levels at coal-fired power plants, including the Jim Bridger plant and Utah Plants. The most recent third-party study completed in December 2025 (the 2025 Coal Inventory Study) is provided as Confidential Exhibit PAC/602. The study recommends maintaining or increasing coal inventory levels beginning in 2025 to address prevailing coal supply conditions and supply risks.

Q. Please provide a summary of the coal fuel stock balances for the company's coal-fired plants discussed in your testimony.

A. My testimony addresses the coal fuel stock balances for all coal-fired plants and focuses primarily on the Utah Plants and the Jim Bridger plant for the Test Year because these sites were most affected by recent coal supply changes and disruptions. Confidential Table 1 shows each plant's coal fuel stock balance in tons and dollars.

Calculations use 13-month average forecasts from December 2026 to December 2027 for the Test Year, and from December 2024 to December 2025 for the Base Year.

Confidential Table 1

*The coal fuel stock balances shown for Colstrip, Craig, Hayden, and Jim Bridger are PacifiCorp's share.
*The 2025 rate case figures for Jim Bridger plant are consistent with the requirements in Order No. 24-447.

A. Utah Plants

Q. Why has the coal fuel stock balance at the Utah Plants increased for the Test Year?

A. As indicated, PacifiCorp experienced significant coal supply disruptions at the Utah Plants resulting in decreased coal production and coal inventories from 2022 to 2024. Due to these disruptions, inventories dropped below target levels. As a result of adhering to prudent coal procurement and inventory practices, the company was able to rely on coal inventories to benefit customers. Inventory levels during that period fell well below the targets established by PacifiCorp's Coal Inventory Policies and Procedures and independent third-party studies. Maintaining inventories at those lower levels would have continued to expose customers to higher costs from increased power market purchases. Therefore, PacifiCorp took steps to restore coal

inventories to recommended levels by working with suppliers to improve long-term coal supply reliability.

As discussed above, during 2022–2023, the Utah Plants received less coal than contracted under existing CSAs due to coal market disruptions. Over that period, Utah coal production declined by [redacted], from [redacted] tons in 2021 to [redacted] tons in 2023, as two coal mines closed or were idled, reducing the number of operating mines from six to four, including only two high-production longwall mines.

During this time, coal inventories at the Utah Plants declined precipitously from approximately [redacted] tons at the start of 2021 to approximately [redacted] tons by the end of 2023. In 2023, the Hunter stockpile reached an all-time low, with PacifiCorp's share falling to only [redacted] tons relative to a capacity of [redacted] tons. At that time, the Utah Plants made up approximately [redacted] of PacifiCorp's owned generation capacity.

To address these supply conditions and reduce future disruption risk, PacifiCorp amended the Hunter/Wolverine CSA and Huntington/Wolverine CSA in February 2024 after evaluating several alternatives and choosing the least-cost, least-risk solution. The CSA amendments provided for a third longwall operation through renewed operations at the Fossil Rock mine. As a result, coal inventories improved and returned to target ranges consistent with recommendations in PacifiCorp's 2025 Coal Inventory Study.

Q. What does the 2025 Coal Inventory Study recommend regarding coal inventory levels for the Utah Plants for the Test Year?

A. The 2025 Coal Inventory Study recommends higher coal inventory target levels for the Utah Plants going forward. These recommendations reflect current market conditions, including increased coal supply concentration and limited alternative coal delivery options for the Utah Plants. Confidential Table 2 below compares these new target levels with those from the prior third-party study conducted in 2021 (2021 Coal Inventory Study),[2] provided as Confidential Exhibit PAC/603, and earlier studies.

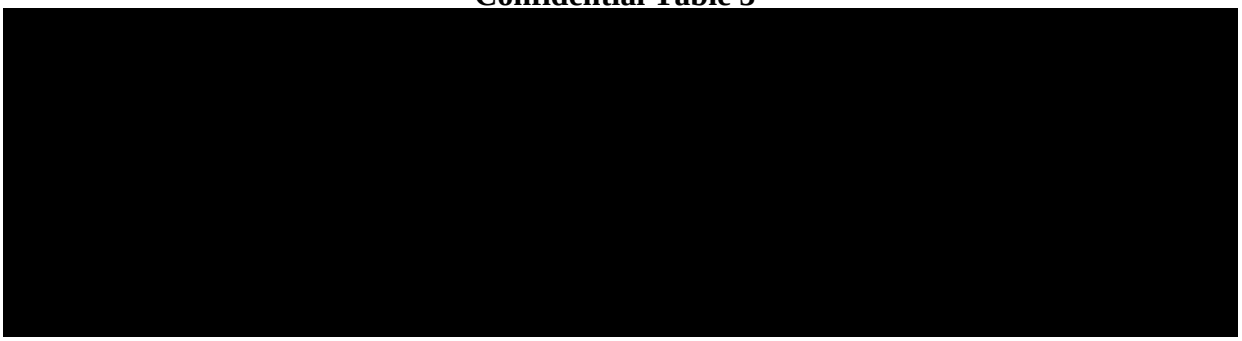
Confidential Table 2

[redacted]

The 2025 Coal Inventory Study sets coal inventory target ranges for the Utah Plants between [redacted] tons and [redacted] tons. The total Utah Plants' capacity of [redacted] tons is indicated in PacifiCorp's Coal Inventory Policies and Procedures.[3] These targets reflect projected coal consumption and updated assessments of supply risk. The Utah Plants' inventory target ranges and plant capacity are shown in Confidential Table 3.

[2] *In the Matter of PacifiCorp, d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 433, Exhibit PAC/3002.
[3] PAC/601, p.10.

Confidential Table 3



Q. According to the 2025 Coal Inventory Study, what are the recommended coal inventory target ranges for the Utah Plants?

A. The 2025 Coal Inventory Study recommends that the Utah Plants should maintain coal inventories between [redacted] days at full plant generating capacity. This is a [redacted] day increase from the [redacted] days recommended in the 2021 Coal Inventory Study, reflecting elevated supply risks and higher potential costs associated with generation shortfalls. The recommendation is based on an in-depth cost curve analysis, as shown in Confidential Table 4 below. The analysis reveals that when inventories fall below [redacted] days of burn, annual coal inventory costs rise sharply due to what the study calls increased foregone generation costs, also referred to as replacement power costs, highlighting the financial risks of supply disruptions.

Confidential Table 4 – Utah Plants Inventory Cost Curve [4]

According to Confidential Table 5, annual costs are $ at days of inventory, $ at days, and reach a low of $ at days. When inventory levels exceed days, increases in working capital costs are mostly offset by lower foregone generation costs. At days, the risk of foregone generation drops to , and total inventory costs remain steady between days. Within this range, the likelihood of foregone generation is at days and at days.

At days (near maximum capacity), total inventory costs are $, lower than at days and similar to the cost at days.[5] Higher inventory levels above minimum requirements contribute to lower inventory costs and a reduced risk of foregone generation.

[4] PAC/602, p. 3.
[5] PAC/602, p. 2.

Confidential Table 5 – Utah Plants:
Inventory Cost and Foregone Generation Risk at Selected Days of Burn[6]

[redacted]

Confidential Table 5 shows once coal inventories exceed [redacted] days of burn, rising working capital costs are offset by falling foregone generation risk. Ultimately, maintaining more than [redacted] days of inventory minimizes costs and reduces the risk of supply-related disruptions.

Q. Why have PacifiCorp's Coal Inventory Policies and Procedures and the 2025 Coal Inventory Study recommended revised coal inventory balances for the Utah Plants?

A. PacifiCorp's Coal Inventory Policies and Procedures together with, the 2025 Coal Inventory Study, recommend increasing coal inventory levels for the Utah Plants beyond the targets established in the 2021 Coal Inventory Study. This recommendation is based on several factors, including [redacted].[7]

The 2025 Coal Inventory Study notes,

[redacted]

[6] PAC/602, p. 3 and Appendix A-1.
[7] PAC/602, p. 1.

[redacted]

- [redacted]
- [redacted]
- [redacted]

Additionally, the 2025 Coal Inventory Study determines that the [redacted]

[redacted]

[8] PAC/602, p. 7.
[9] PAC/602, p. 29.

Q. Please provide some historical context for coal deliveries and inventory levels for the Utah Plants, including actual inventory in prior years and the coal inventory forecast for the Test Year.

A. Confidential Table 6 below presents annual coal deliveries, consumption, and inventory levels for the Hunter plant, alongside the 2027 forecast. The Hunter/Wolverine CSA obligates deliveries of [redacted] tons in 2027, inclusive of PacifiCorp's ownership share and the shares of the other joint owners. PacifiCorp has an 84.968 percent ownership interest in Hunter's three coal-fired units. Typically, the Hunter plant consumes more than [redacted] tons annually, except in 2023 and 2024, due to constrained coal deliveries. On-site inventory capacity is approximately [redacted] tons. The projected 13-month average coal fuel stock balance for 2027 is $[redacted] from [redacted] tons, as previously shown in Confidential Table 1 above.

Confidential Table 6

Confidential Table 7 addresses the Huntington plant, which has a 2027 contractual coal volume of [redacted] tons and a combined on-site capacity of approximately [redacted] tons, including the Rock Garden coal reserve stockpile. Excess deliveries are directed toward building inventory, including the Rock Garden, which was depleted in 2023 but was largely replenished by 2025. Historically, the Rock Garden stockpile has fluctuated and currently contains about [redacted] tons, with a capacity of approximately [redacted] tons.

Huntington has historically met or exceeded the [redacted]-ton contractual minimum except in supply-constrained years (2022–2023). The projected 13-month average coal fuel stock balance for Huntington and Rock Garden combined in 2027 is $[redacted] from [redacted] tons.

Confidential Table 7

[redacted]

B. Jim Bridger Plant

Q. What is the 2027 coal fuel inventory forecast for the Jim Bridger plant?

A. The forecasted 13-month average coal fuel inventory balance for the Jim Bridger plant for the Test Year is $[redacted] from [redacted] tons, as outlined in Confidential Table 1 above. Recently, the plant has received coal from two sources: (1) the Bridger Coal Company surface mine adjacent to the plant, and (2) Powder River Basin coal, delivered by rail in limited volumes from approximately 550 miles away. Following the closure of the Bridger Coal Company underground mine in 2021, the Jim Bridger plant has moved from four reliable coal supply sources to two—the Bridger Coal Company surface mine and the Powder River Basin mines.

Q. How did the Commission address Jim Bridger coal fuel stock in the 2025 rate case?

A. In Docket UE 433, Order No. 24–447, the Commission adopted an adjustment to PacifiCorp's Jim Bridger coal fuel inventory target, limiting the target level to [redacted] days of burn, reasoning that since Units 1 and 2 were converted to natural gas and only Units 3 and 4 continue to operate as coal-fired units, the target should be effectively reduced by half.[10] The Order determined that the coal inventory should be [redacted] tons, with an associated dollar amount of $[redacted].

Q. What does the 2025 Coal Inventory Study recommend for Jim Bridger coal inventory targets compared to prior studies?

A. The 2025 Coal Inventory Study recommends increasing the coal inventory target from [redacted] days of burn (when all four units operated on coal) to [redacted] days of burn

[10] *Public Utility Commission of Oregon, Order No. 24-447, Docket UE 433 (Dec. 19, 2024), at pp. 51-52.*

for the remaining two coal-fired units (Units 3 and 4), thereby maintaining stockpiles at full capacity. This study's recommendation is supported by updated cost analyses and current coal supply conditions, which indicate that higher inventory levels are appropriate to mitigate foregone generation risk and constrained coal supply options.

The 2025 Coal Inventory Study builds upon the recommendations in the 2021 Coal Inventory Study, which targeted [redacted] days of burn for all coal-fired units and aimed to retain inventories near full capacity to minimize foregone generation risk. Following the conversion of Units 1 and 2 to natural gas in 2024, the Jim Bridger plant's coal supply risk profile has shifted, prompting the need for higher inventory reserves. The analysis indicates that inventory costs decrease up to [redacted] days of burn, which is just short of full capacity, supporting the updated target.

As stated in the 2025 Coal Inventory Study;

[redacted][11]

Consistent with the 2025 Coal Inventory Study's recommendations, PacifiCorp revised its Coal Inventory Policies and Procedures, setting new targets for the Jim Bridger plant. Confidential Table 8 below provides an itemization of the plant's coal inventory targets established in the PacifiCorp Coal Inventory Policies and Procedures, provided as Confidential Exhibit PAC/601.[12]

[11] PAC/602, p. 4-5.
[12] PAC/601, p. 12.

Confidential Table 8 – Jim Bridger Plant Inventory Targets

Confidential Table 9 presents the annual inventory cost across inventory levels up to the plant's [redacted] days of burn capacity, as modeled in the 2025 Coal Inventory Study.

Confidential Table 9 – Jim Bridger Plant Inventory Cost Curve[13]

[13] PAC/602, p. 4.

Q. How does the recommended [redacted] days of burn inventory target for Jim Bridger affect expected inventory costs and foregone generation risk?

A. The 2025 Coal Inventory Study demonstrates that maintaining inventory at [redacted] days of burn for Units 3 and 4 results in lower total annual inventory costs and reduced foregone generation risk. Confidential Table 10 illustrates that at [redacted] days, the annual inventory cost is $[redacted] with a [redacted] risk of foregone generation; at [redacted] days, the annual inventory cost decreases to [redacted] and the risk of foregone generation declines to [redacted]; and at [redacted] days—the full plant inventory capacity for Units 3 and 4 combined—the cost is $[redacted] with a [redacted] risk. Within the recommended range of [redacted] days of burn, inventory costs remain stable, while foregone generation risk is significantly reduced. Accordingly, a reserve of [redacted] days of burn represents the optimal balance of cost efficiency and operational reliability.

Confidential Table 10 – Jim Bridger Plant:
Inventory Cost and Foregone Generation Risk[14]

[redacted]

[14] PAC/602, p. 5, and Appendix A-2.

Q. What factors determine the company's recommended days of burn target for the Jim Bridger plant in Test Year 2027?

A. The principal determinant for the [redacted] days inventory target, as indicated in the 2025 Coal Inventory Study, is the difference between expected coal consumption and forecasted coal deliveries under high-impact, low-probability events, including unspecified disruptions. Additional factors include:

- [redacted][15]
- [redacted][16]
- [redacted][17]
- [redacted][18]
- [redacted][19]
- [redacted][20]
- [redacted][21]
- [redacted][22]

The 2025 Coal Inventory Study recommends keeping Jim Bridger inventories at full capacity, targeting [redacted] days of burn to minimize costs and ensure reliable service to meet generation requirements.

[15] PAC/602, p. 5, Figure 1-4.
[16] PAC/602, p. 31.
[17] PAC/602, p. 12, 33.
[18] PAC/602, p. 1, 29.
[19] PAC/602, p. 16, 33.
[20] PAC/602, p. 13.
[21] PAC/602, p. 55.
[22] *Id.*

Q. What coal inventory levels does PacifiCorp propose the Commission approve in this proceeding?

A. I recommend that the Commission approve PacifiCorp's forecast coal inventory balances for the Test Year as proposed in this filing. These inventory levels are consistent with PacifiCorp's Coal Inventory Policies and Procedures and are well supported by the analyses presented in the independent 2025 Coal Inventory Study. The forecast coal inventory levels are reasonable and prudent and represent a least-cost, least-risk solution under current coal supply conditions.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 470
Exhibit PAC/601
Witness: Jayson D. Branch

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Jayson D. Branch

PacifiCorp Coal Inventory Policies and Procedures (February 2026)

May 2026

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

REDACTED
Docket No. UE 470
Exhibit PAC/602
Witness: Jayson D. Branch

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Jayson D. Branch

Coal Inventory Study for PacifiCorp Coal-Fired Power Plants in Wyoming and Utah
(December 2025)

May 2026

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REDACTED
Docket No. UE 470
Exhibit PAC/603
Witness: Jayson D. Branch

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Jayson D. Branch

Coal Inventory Study for PacifiCorp Coal-Fired Power Plants in Wyoming and Utah
(March 2021)

May 2026

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

Docket No. UE 470
Exhibit PAC/700
Witness: Travis R. Walker

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Travis R. Walker

May 2026

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ATTACHED EXHIBIT

Exhibit PAC/701—Oregon Load Forecast Model Specifications Presentation

I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power.

A. My name is Travis R. Walker. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Senior Business Specialist.

Q. Please describe your education and professional experience.

A. I have a Bachelor's Degree in Economics and Political Science from University of Oregon. I have been employed by PacifiCorp since September 2019, where I have designed and implemented load research studies. Before I joined PacifiCorp, I was a senior consultant with The Cadmus Group where I managed energy efficiency planning and evaluation studies.

II. SUMMARIZATION OF LOAD FORECAST

Q. Please summarize your testimony on PacifiCorp's sales and load forecast.

A. I provide PacifiCorp's forecasts of the number of customers, kilowatt-hour (kWh) sales at the meter (sales), system loads and system peak loads at the system input level (loads), and number of bills by rate schedule for the 12-month period ending December 31, 2027. PacifiCorp's load forecast has been updated with the most recent information available and includes a change in methodology to more accurately forecast load.

Q. When did PacifiCorp prepare the sales and load forecast used in this filing?

A. The sales and load forecast used in this filing was completed in January 2026. The January 2026 sales and load forecast is the most recent forecast of sales and loads prepared by the company.

Q. What is the difference between sales and load?

A. Sales are measured at the customer meter, while load is measured at the generator or system input level.

Q. How did the company use the sales and load forecast in its preparation of this rate case?

A. The load forecast was used by company witness Shelley E. McCoy to calculate the inter-jurisdictional allocation factors. The sales forecast by rate schedule was used by company witness Kenneth L. Elder, Jr. to allocate costs between customer classes and by company witness Judith M. Ridenour to design rates that correctly reflect the cost of service.

Q. Please provide a general overview of PacifiCorp's sales and load forecast methodology.

A. PacifiCorp first develops a forecast of monthly sales by customer class and monthly peak load by state. This sales forecast becomes the basis of the load forecast by adding line losses, meaning kWh sales levels are grossed up to a generation or "input" level. The monthly loads are then spread to each hour based on the peak load forecast and typical hourly load patterns to produce the hourly load forecast.

Q. Please provide a summary of the forecast energy sales for 2027.

A. Table 1 provides the forecasted energy sales for the 12-month period ending December 31, 2027 (Test Period).

Table 1. Test Period Sales Forecast (MWh)

	2027 Rate Case	
	Total Company	**Oregon**
Residential	**18,628,903**	**5,718,475**
Commercial	**25,588,036**	**8,715,838**
Industrial	**17,226,273**	**1,363,188**
Irrigation	**1,437,453**	**245,887**
Lighting	**100,554**	**28,888**
Total	**62,981,219**	**16,072,275**

Q. How does the total-company sales forecast for 2027 compare to the sales forecast used in the 2025 rate case?

A. As shown in Table 2, total-company 2027 forecast sales are 1.5 percent higher than 2025 forecast sales used in the 2025 rate case. The difference in the forecasts is attributable to increases in residential and commercial sales offset by decreases in industrial and irrigation sales. The residential forecast increase is attributable to continued customer growth in all states except Wyoming. The commercial class increase in the forecast is attributable to higher large customer projections in Oregon and Utah. The industrial class decrease is due to reduced forecasts for large customers and reduced expectations for customers in lumber products and chemical manufacturing sectors.

Table 2. Total-Company Sales Comparison (MWh)

	2025 Rate Case CY 2025	2027 Rate Case CY 2027	Percentage Change
Residential	**18,229,909**	**18,628,903**	**2.2%**
Commercial	**23,791,222**	**25,588,036**	**7.6%**
Industrial	**18,467,000**	**17,226,273**	**-6.7%**
Irrigation	**1,464,877**	**1,437,453**	**-1.9%**
Lighting	**98,916**	**100,554**	**1.7%**
Total	**62,051,923**	**62,981,219**	**1.5%**

Q. How does the Oregon sales forecast for 2027 compare to the sales forecast for the 2025 rate case?

A. As shown in Table 3, the 2027 Oregon sales forecast has increased by 2.5 percent from the 2025 sales forecast used in the 2025 rate case. In Oregon, the residential class forecast is lower due to lower use per customer from existing roof top solar penetration. The commercial class increase in the forecast is attributable to data center growth expectations. The Industrial forecast is lower due to declines in several industries, including wood products, food products and machinery. The irrigation class forecast is lower due to decreasing acreage in production, while the lighting class is lower due to light-emitting diode (LED) adoption.

Table 3. Oregon Sales Comparison (MWh)

	2025 Rate Case CY 2025	2027 Rate Case CY 2027	Percentage Change
Residential	**5,936,359**	**5,718,475**	**-3.7%**
Commercial	**7,986,695**	**8,715,838**	**9.1%**
Industrial	**1,467,541**	**1,363,188**	**-7.1%**
Irrigation	**254,046**	**245,887**	**-3.2%**
Lighting	**30,286**	**28,888**	**-4.6%**
Total	**15,674,929**	**16,072,275**	**2.5%**

III. LOAD FORECAST METHODOLOGY

Q. Please summarize the major updates used to produce this forecast as compared to the forecast used in the 2025 rate case.

A. PacifiCorp updated many of its data inputs when compared to the forecast prepared for the 2025 rate case. For each of these updates, the company used the most recent information available.

1. For Oregon, the residential and commercial classes use a historical data period of January 2006 through February 2025. The historical data period used to develop the industrial monthly sales is from January 2008 through February 2025. The irrigation class uses the historical data period of January 2006 through February 2025, while the lighting class uses the historical data period of April 2006 through February 2025.
2. The company updated the historical data period used to develop the monthly peak forecasts to include March 2008 through December 2024.
3. The company updated the economic drivers for each of the company's jurisdictions using S&P Global data released in March 2025.

4. The company updated the forecast for individual industrial and commercial customer usage based on the best information available as of January 2026.
5. The time period used to calculate normal weather was defined as the 20-year time period of 2005 through 2024.
6. The company used the climate change impact estimate from the March 2021 United States Bureau of Reclamation to adjust the normal weather for expected climate change impacts.[1]
7. The company rolled forward the line loss calculation to the five-year period ending December 2024.
8. The data used to develop temperature splines was rolled forward based on available customer class hourly data (October 2019 through September 2024).
9. The company used the residential use-per-customer model with appliance saturation and efficiency results released in October 2023.

Q. Are there any changes in the load forecast methodology since the 2025 rate case?

A. Yes. PacifiCorp has updated its electric vehicle adoption forecast methodology to use hourly electrical vehicle (EV) load shapes to calculate the EV load instead of adding the EV load to jurisdictional loads and shaping it based on the jurisdictional load shape.

Historically, EV loads were added to jurisdictional loads and shaped based on jurisdictional load shape. While electric vehicle loads were small, this approach generated satisfactory results, but with growing EV adoption, EV loads have an

[1] United States Bureau of Reclamation, March 2021, Managing Water in the West, Technical Memorandum No. ENV-2021-001, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2021secure/westwidesecurereport1-2.pdf.

increasing potential impact on loads and peaks. It is important that this growing impact on loads be modeled accurately so that PacifiCorp can plan for the load effectively and so that programs to mitigate for this growth can be explored. PacifiCorp also updated the Oregon residential use per customer model to incorporate the impacts of existing solar customers systems impact on use per customer within the other use variable.

Monthly Sales Forecast Methodology

Q. How are the forecasts for number of customers developed?

A. For the residential class, PacifiCorp forecasts the number of customers using S&P Global's forecast of number of households or population as the major driver. For the commercial, industrial, irrigation and street lighting classes, the customer forecasts are fairly static and developed using time series or regression models without any economic drivers.

Q. What methodology does PacifiCorp use to forecast the residential class sales?

A. PacifiCorp develops the residential sales forecasts as a product of two separate forecasts: (1) the number of customers, as described above, and (2) sales per customer. PacifiCorp models sales per customer for the residential class through a statistically adjusted end-use model, which combines the end-use modeling concepts with traditional regression analysis techniques.

Q. What methodology does the company use to forecast the commercial class sales?

A. For the commercial class, PacifiCorp forecasts sales using regression analysis techniques with non-manufacturing employment or non-farm employment, as the economic drivers, in addition to weather-related variables. Also, similar to how

PacifiCorp forecasts its largest industrial customers, large commercial customers such as data centers are based on input from the company's regional business managers.

Q. How does PacifiCorp forecast sales for the industrial customer class?

A. Most industrial customers are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver. For a small number of industrial customers (the largest on the system), PacifiCorp individually prepares forecasts based on input from the customer and the company's regional business managers.

Q. What methodology does PacifiCorp use for the irrigation and lighting sales forecasts?

A. For the irrigation class, PacifiCorp forecasts sales using regression analysis techniques based on historical sales volumes and weather-related variables. Monthly sales for lighting are forecast using regression analysis techniques based on historical sales volumes and an LED lighting adoption curve.

Hourly Load Forecast

Q. Please outline how the hourly load forecast is developed.

A. After PacifiCorp develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps. First, monthly peak forecasts are developed for each state. The monthly peak model uses historical peak-producing weather for each state and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. This forecast is based on average monthly historical peak-producing weather for January 2004 through December 2023.

Second, hourly load forecasts are developed for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures identified above, a typical annual weather pattern, and day-type variables such as weekends and holidays as inputs to the model. The hourly loads are adjusted to match the monthly peaks from the first step above. Also, the hourly loads are adjusted so the monthly sum of hourly loads equals monthly sales plus line losses.

Q. How are monthly system coincident peaks derived?

A. After the hourly load forecasts are developed for each state, hourly loads are aggregated to the total system level. The system coincident peaks can then be identified, as well as the contribution of each jurisdiction to those monthly peaks.

Forecasts by Rate Schedule

Q. Were any additional forecasts created for these proceedings?

A. Yes. As mentioned earlier, witness Ridenour required two additional forecasts that are based on the kWh sales forecast and the number of customers forecast. Once the kWh sales forecast is complete, it must be applied to individual rate schedules to forecast kWh sales by rate schedule. In addition, the forecast of number of customers by rate schedule must be expressed in number of bills.

Q. How are rate schedule level forecasts produced?

A. PacifiCorp develops this forecast in two steps: (1) it forecasts test year sales by rate schedule; and (2) it proportionally adjusts the rate schedule sales forecasts so that the total matches the customer class forecast.

Q. Finally, how does PacifiCorp forecast the number of bills for each rate schedule?

A. The forecast of the number of bills for each rate schedule follows the same process as the sales forecast for each rate schedule. First, PacifiCorp forecasts the number of bills by class and by rate schedule. Then, PacifiCorp proportionally adjusts the forecasted number of bills by rate schedule so that the total number of bills matches the customer class forecasted number of bills.

IV. DISCUSSION OF OUTCOMES FROM 2025 RATE CASE

Q. Are there any outstanding issues from the company's 2025 rate case that were required to be addressed for this rate case?

A. Yes. As part of the 2025 rate case, the company committed to hosting a workshop to address Public Utility Commission of Oregon (Commission) Staff (Staff)'s load forecast recommendations which are as follows:

Staff Recommendations

1. Use algorithmically parameterized autoregressive integrated moving average models as the baseline forecast model and document and explain any deviations from these prescribed models.

2. Present evidence showing that the use of PacifiCorp's 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 software which allows for differencing of models or present evidence for each of the models justifying the differencing, or lack thereof, for each model.

4. Host load forecasting workshop between now and their next general rate case to facilitate staff and intervenor input into these analyses.

Q. Did PacifiCorp hold a workshop to address Staff's recommendations?

A. Yes, on November 19, 2025, the company hosted a workshop to address staff's recommendations.

Q. Did the company test Staff's recommendation to use algorithmically parameterized models?

A. Yes, the company tested developing models using the Hyndman-Khandakar algorithm recommended in Staff's 2025 rate case testimony. The company found that 75 percent of the models suggested by the algorithm had one or more issues that would preclude their use in rate cases and recommended the procedure not be used.

Q. Was there a resolution to this issue?

A. Yes, in further discussion in the workshop with Staff it became clear that Staff's goal was for the company to provide greater transparency in the modeling process and reduce Staff's workload by providing improved insight into how the modeling changes are determined. The company agreed to enhance its load forecast documentation to include discussion of modeling decisions and the reasoning for each decision.

Q. Did PacifiCorp address Staff's recommendation to justify the use of SAE variables?

A. Yes, the company conducted an analysis that compared the forecast performance of models using the company's SAE variables to models using more transparent heating degree day and cooling degree day (simplified) variables. The company compared the performance of models using SAE variables and models using simplified variables to weather normalized actuals for the forecasts used in the 2020 to 2024 Transition

Adjustment Mechanisms. PacifiCorp calculated the monthly mean absolute percentage error (MAPE) of each forecast (SAE and Simplified) and compared the MAPEs for each forecast method.

Q. What were the results of the company testing?

A. PacifiCorp found that the SAE models produced an average MAPE of 4.75 percent as compared to the MAPE of 5.27 percent produced by the simplified models. On average the error percentage was reduced by 0.51 percent, a 10 percent improvement, using the SAE variables compared to the simplified variables, justifying the inclusion of SAE variables.

Q. How did PacifiCorp respond to Staffs request that the company use software which allows for differencing of models or present evidence for each of the models justifying the differencing, or lack thereof, for each model?

A. PacifiCorp discussed with Staff how it has in place a process that allows the company to difference the residential customer models. The company reviewed the remainder of the sales models for stationarity using the Augmented Dickey Fuller test to demonstrate the stationarity of the residuals in these models. The company agreed to enhance the model outputs provided in future data responses to include the Augmented Dickey Fuller test to demonstrate that no further differencing is necessary.

V. CONCLUSION

Q. What is your recommendation for the Commission?

A. I recommend that the Commission approve the company's load forecast for use in its 2027 rate case.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 470
Exhibit PAC/701
Witness: Travis R. Walker

BEFORE THE PUBLIC UTILITY COMMISSION

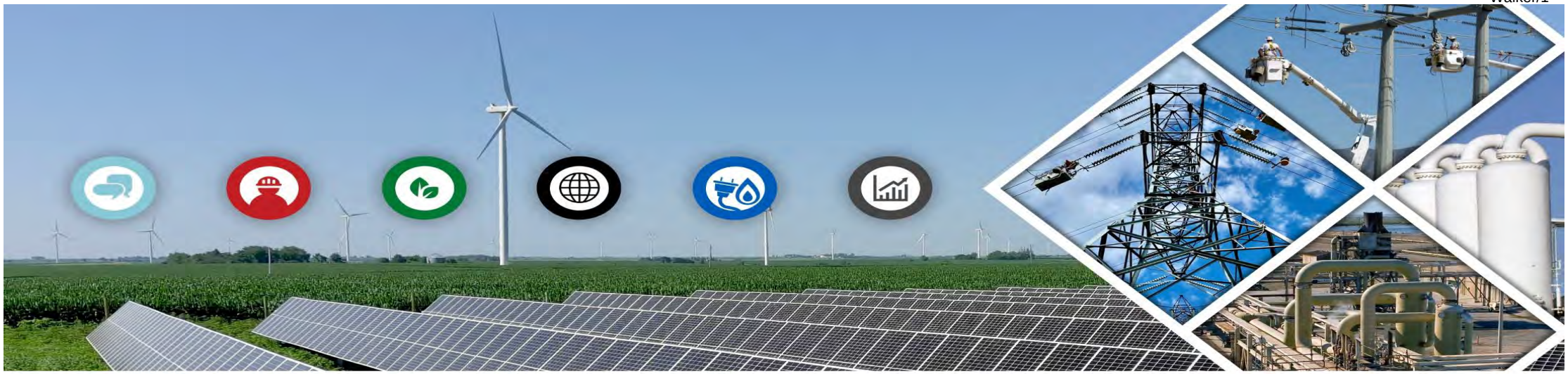
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Travis R. Walker

Oregon Load Forecast Model Specifications Presentation

May 2026



Oregon Load Forecast Model Specifications

November 19, 2025

Agenda

- Overview of forecast methodology
- Staff recommendations
  - Automatic ARIMA selection
  - XHeat/XCool vs CDD/HDD in Residential Models
  - Software that allows for differencing
  - Conduct load forecast workshop

Oregon Modeling Overview

Sales Forecast

- PacifiCorp forecast sales using linear regression modeling, which include economic drivers and weather-related variables. The Commercial model uses non-manufacturing employment, while the Industrial model uses manufacturing employment

- For the residential class, PacifiCorp models sales-per-customer through a Statistically Adjusted End-Use model, which combines the end-use modeling concepts with traditional regression analysis techniques

Customer Forecast

- The Residential customer model uses households as the economic driver. For the commercial, industrial, irrigation and street lighting classes, the customer forecasts are relatively static and developed using exponential smoothing models without any economic drivers.

- The Residential class level sales forecast is the customer forecast multiplied by the sales-per-customer forecast

Model Development Process

- Evaluate the accuracy of prior year's models and take note of any changes in economic conditions
- Update actuals and vintage of economic drivers
- Check significance of predictors
- Plots of residuals. Check if any outliers can be explained by known events or trends
- Choose ARMA terms by evaluating ACF/PACF (auto-correlation function and partial auto-correlation function)
- Assess elasticities of variables
- Evaluate measures of fit, including AIC/BIC (Akaike Information Criterion / Bayesian Information Criterion)
- Measures of autocorrelation (Durbin-Watson Statistic and Ljung-Box)
- Check the reasonableness of the long-term trend

Background

As part of the 2024 General Rate Case, PacifiCorp committed to hosting a workshop to address staff's load forecast recommendations

Staff Recommendations

1. Use algorithmically parameterized autoregressive integrated moving average (ARIMA) models as the baseline forecast model and document and explain any deviations from these prescribed models

2. Present evidence showing that the use of PacifiCorp's 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 the models justifying the differencing, or lack thereof, for each model

4. Host load forecasting workshop between now and their next general rate case to facilitate staff and intervenor input into these analyses

Automatic ARIMA Discussion

Staff Recommendation

1. Use algorithmically parameterized autoregressive integrated moving average (ARIMA) models as the baseline forecast model and document and explain any deviations from these prescribed models

Automatic ARIMA Overview

- The Automatic ARIMA selection process is based on Hyndman-Khandakar (HK) algorithm recommended by OPUC Staff
- The HK algorithm is a method designed to automate the process of fitting ARIMA models, it is useful when dealing with a large number of univariate time series
- The algorithm starts by evaluating the need for differencing data. If needed, the algorithm differences the data
- Next, different ARMA parameter combinations are tested by comparing the Akaike Information Criterion (AIC) of the resulting models. The model with the lowest AIC is chosen as the best model

Automatic ARIMA Results

Testing procedure

1) Tested all Oregon models for 2020 to 2027 TAM forecasts using the HK algorithm

Issues Found

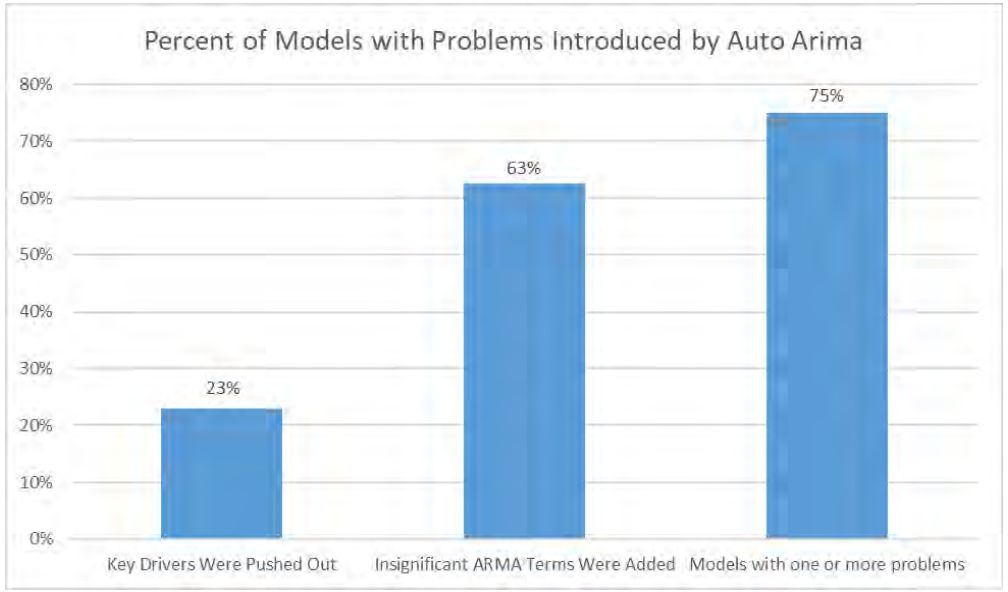
1) Key drivers (economic and SAE) were made insignificant in 23 percent of models

2) Recommended insignificant ARMA terms in 63 percent of models

3) 75 percent of the suggested models had 1 or more issues

Other Issues

1) HK algorithm is known for over-specifying models including two seasonal ARMA variables
2) HK algorithm recommended differencing in cases where no unit root existed



PacifiCorp Recommendation

1) Given that 75 percent of models produced by the HK Algorithm are not usable, PacifiCorp feels that reviewing lists of these models is not a good use of Company and stakeholder time
2) Recommend using existing linear regression with ARMA methodology

XHeat and XCool Discussion

Staff Recommendation

1. Present evidence showing that the use of PacifiCorp's 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

XHeat and XCool Overview

- The Company uses Itron SAE framework, which combines appliance end-use intensities based on Energy Information Administration (EIA) data, appliance saturation data from the Company's residential survey and weather data (Residential Heating Degree Days and Cooling Degree Days)

- XHeat and XCool are variables that are constructed from weather variables and information about the use of weather sensitive appliances

  - $\text{XHeat} = \text{Heat end use intensity} * \text{Heat end use saturation} * \text{Res_HDD}$
  - $\text{XCool} = \text{Cool end use intensity} * \text{Cool end use saturation} * \text{Res_CDD}$

XHeat and XCool Testing

Testing procedure

1) Replaced XHeat and XCool with Res_HDD and Res_CDD respectively then compared monthly Forecast to Weather Normalized (WN) Actuals for each forecast.

2) The Company tested the forecasts used for the 2020 to 2024 TAM forecasts to test year actuals

3) The Company calculated the monthly Mean Average Percentage Error (MAPE) of each forecast then averaged across the 5 forecasts

XHeat and XCool Results

Results

1) The average MAPE for the XHeat and XCool models was 0.51% lower than the Res_HDD and Res_CDD method, a 9.77% improvement

Other Considerations

1) The SAE Model incorporates changing appliance intensities and saturations over time and is necessary for longer term forecasting

2) Using the same forecast for Integrated Resource Planning, Business Planning and rate making simplifies forecasting for both the Company and other parties

5 Year Average MAPE

XHeat_XCool	4.75%
HDD_CDD	5.27%
Change	0.51%
Improvement	9.77%

PacifiCorp Recommendation

1) A 10% MAPE improvement supports using the SAE model
2) Recommend using existing XHeat and XCool variables in the Company's residential use per customer model

Differencing Discussion

Staff Recommendation

1. Use a software which allows for differencing of models or present evidence for each of the models justifying the differencing, or lack thereof, for each model

Differencing Overview

- While the Company's software Itron's Metrix ND does not have native support for differencing, the Company has successfully incorporated differencing into the residential customer model

Results

- The Company has reviewed the remainder of the sales models for stationarity. Using Augmented Dickey Fuller (ADF) tests demonstrates stationarity of the residuals in these models

Recommendation

- The Company will incorporate the results of these ADF tests in its model outputs provided in data responses in future proceedings

Docket No. UE 470
Exhibit PAC/800
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Shelley E. McCoy

May 2026

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ATTACHED EXHIBITS

Exhibit PAC/801—Revenue Requirement Summary

Exhibit PAC/802—Oregon Results of Operations – December 2027

Exhibit PAC/803—Washington Service Area Transfer Impact – December 2027

Confidential Exhibit PAC/804—PacifiCorp's Property Tax Estimation Procedure

Confidential Exhibit PAC/805—S&P Market Intelligence Power Planner Data

Confidential Exhibit PAC/806—REC Revenues Adjustment Support

Confidential Exhibit PAC/807—Bridger Mine Reclamation and Decommissioning Costs Support

Confidential Exhibit PAC/808—New Wind Generation Capital Additions Support

Exhibit PAC/809—Proposed Amortization of Deferral Balances and Goodwill Value of Washington Service Area Transfer

Exhibit PAC/810—Wildfire Mitigation Plan Automatic Adjustment Clause True-Up Illustration

Exhibit PAC/811—Interim Rates Revenue Requirement Calculation

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address and present position with PacifiCorp d/b/a Pacific Power.

A. My name is Shelley E. McCoy, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as the Director of Revenue Requirement at PacifiCorp.

Q. Briefly describe your education and professional background.

A. I earned a Bachelor of Science degree in Accounting from Portland State University in 1990. In addition to my formal education, I have attended several utility accounting, ratemaking, and leadership seminars and courses. I have been employed by PacifiCorp since November 1996. My past responsibilities have included general and regulatory accounting, budgeting, forecasting, and reporting. I assumed my current position in November 2022.

Q. What are your responsibilities as Director of Revenue Requirement?

A. My primary responsibilities include overseeing the calculation and reporting of the company's regulated earnings or revenue requirement, ensuring that the inter-jurisdictional cost-allocation methodology is correctly applied, and explaining those calculations to regulators in the jurisdictions in which the company operates.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony in multiple dockets before the Oregon, California, Idaho, Utah, Washington, and Wyoming public utility commissions.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony in this case?

A. My direct testimony addresses the calculation of the company's Oregon-allocated revenue requirement, excluding net power costs (NPC), and the revenue increase requested in the company's filing. Specifically, I provide testimony on the following:

- The calculation of the $161.7 million revenue increase requested in this general rate case (GRC) representing the increase over current rates required for the company to recover its Oregon non-NPC revenue requirement of $1,393.6 million under current operating conditions. The company currently recovers its NPC through the Transition Adjustment Mechanism (TAM).
- The selection of the historical period of the 12 months ended June 2025 (Base Period) as the basis for the test period in this proceeding.
- The development of the forecast test year in this case, which is the 12-month period ending December 31, 2027 (Test Period).
- The treatment of forecasted capital additions included in the revenue requirement calculations, which have been limited to projects placed in service by March 31, 2027, and the rate base methodology proposed in this case.
- The presentation of the normalized results of operations for the Test Period demonstrating that under current rates and current operating conditions the company will earn an overall return on equity (ROE) in Oregon of 7.2 percent, which is less than the company's currently authorized ROE of 9.5 percent and the 9.7 percent requested by the company and supported by company witness Ann E. Bulkley in this proceeding.

- Projected non-net power costs (non-NPC) revenue requirement impact of the proposed sale of PacifiCorp's Washington service area and certain Washington-based assets (Service Area Transfer), prior to the sharing of the associated goodwill value of the business.
- The company's proposal of a two-step price change to first implement a rate change for revenue requirement increases calculated under current operating conditions (i.e. prior to the approval of the Service Area Transfer), and then upon approval and closing of the Service Area Transfer, a second price change to reflect in rates the non-NPC revenue requirement impact of the transaction.
- The company's proposal for passing back to Oregon customers any rate credits for the sharing of the associated goodwill value of the business from the Service Area Transfer through Oregon's Property Sales Balancing Account.
- An overview of deferral balances the company is seeking to begin amortization of starting on the rate effective date of this case. These deferrals include costs associated with the Rock Creek I Wind Project, the Rock Creek II Wind Project, the Renewable Adjustment Clause (RAC) residential rate change delay resulting from statutory requirements, and incremental liability insurance premiums. My testimony also addresses the necessary true-up to the WMP AAC schedule, consistent with the 2023 AAC[1] settlement and the approach approved in docket UE 433, to reflect indirect loadings and updated return assumptions.

[1] *Advice No. 23-015 Update to Schedule 190, Wildfire Mitigation Plan Cost Recovery Adjustment*, Docket No. ADV 1529, Compliance Letter (Jan. 9, 2024).

- Calculations supporting the price change request under the company's interim rates proposal described in the direct testimony of company witnesses Ryan L. Flynn and Rick T. Link.

Q. How have you organized your testimony?

A. I have divided my testimony into six sections. I discuss the development of the company's revenue requirement, including the base and test periods, in Section III, Revenue Requirement. In Section IV, Inter-jurisdictional Allocations, I address the allocation methodology used in this filing. In Section V, Oregon Results of Operations, I provide a description of the Oregon Results of Operations, including a review of the information contained in Exhibit PAC/802. In Section VI, I explain the process by which rate impacts associated with the proposed Service Area Transfer are calculated and discuss the mechanism by which rate credits will be passed back to Oregon customers upon closing of the Serve Area Transfer. In Section VII, I discuss the calculation of the interim rate change that the company is seeking as part of this general rate case application. Finally, in Section VIII, I provide a description of requested changes to rate schedules that the company is seeking beyond its base rate price change in this case, including those proposed for deferral amortizations outlined above.

III. REVENUE REQUIREMENT

Q. Please summarize the price change request in this GRC filing.

A. The company's requested non-NPC price change in this GRC, assuming the requested interim rate change, is summarized in Table 1 below:

Table 1 – Summary of GRC Price Change

	$ million
Interim Price Change – Effective 6/4/2026	$55.1
Remaining Price Change – Effective 7/15/2026	$106.6
Total Non-NPC Price Change Before Service Area Transfer	**$161.7**
Incremental Price Change (Service Area Transfer)	$17.3
Non-NPC Base Rate Price Change	**$179.0**
Annual Deferral Amortizations - All Customers	$5.8
Annual Deferral Amortization[2] - Residential Only	$1.8
WMP AAC Update (Illustrative)	$1.4
Property Sales – Service Area Transfer Credit	($14.3)
Net Requested Non-NPC Price Change	**$173.7**

Q. What is the revenue requirement[3] to achieve the requested ROE in this case?

A. Before consideration of impacts from the Service Area Transfer, at current rate levels, the company will earn an overall ROE in Oregon of 7.2 percent during the Test Period. This return is less than the 9.5 percent ROE authorized in the company's 2025 general rate case, docket UE 433 (2025 Rate Case).[4] The company is proposing to change the authorized ROE in this case to 9.7 percent. A 9.7 percent ROE produces a non-NPC revenue requirement of $1,393.6 million based on the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol). Exhibit PAC/801 provides a summary of the company's Oregon-allocated results of operations for the Test Period. Exhibit PAC/802 provides the supporting details and calculations and is discussed in greater detail later in my testimony.

[2] Proposed amortization of Docket No. UM 2426 Costs Relating to the Renewable Adjustment Clause associated with the delayed rate change due to House Bill 3179, the Fairness & Affordability in Residential (FAIR) Energy Act, which will be collected from residential customers only.
[3] In Sections III through V, discussion of revenue requirement development is specific to calculations assuming current operating conditions before any consideration of the Washington Service Area Transfer. Impacts on revenue requirement resulting from the Service Area Transfer will be specifically discussed in Section VII.
[4] *In the matter of PacifiCorp dba Pacific Power Request for a General Rate Revision,* Docket No. UE 433, Order No. 24-447 at 12 (Dec. 19, 2024). The Commission set an overall rate of return at 7.4 percent and an authorized return on equity of 9.5 percent.

Q. Please explain how NPC is treated in this filing.

A. As noted above, the company recovers its NPC through the TAM, which was filed in advance of this GRC on April 1, 2026, for calendar year 2027 NPC, in docket UE 469 (2027 TAM). To model the non-NPC revenue requirement for this case, PacifiCorp first computed an overall Test Period revenue requirement including the NPC as filed in the TAM and then removed the NPC components from the overall price change. This approach is required to compute certain non-NPC components of the Test Period revenue requirement that are impacted by NPC-related items, such as the embedded cost differential (ECD), and various revenue-sensitive items. Details supporting the overall revenue requirement and the breakout between the TAM and GRC are provided in Exhibit PAC/801. Page 1 of Exhibit PAC/801 also shows the division of revenue requirement between the TAM and GRC components, and the resulting GRC-related price change requested in this case.

Q. What Test Period did the company use to determine revenue requirement in this case?

A. The forecast Test Period used by the company in this proceeding starts with the 12-month historical period ending June 30, 2025, forecasted to the 12 months ending December 31, 2027.

Q. Why did the company choose the year ending December 31, 2027, as the Test Period?

A. The Test Period in this case was selected to best reflect the conditions during the time the new rates will become effective—July 15, 2027, assuming that the company's interim rate request is granted, or April 5, 2027, if the interim rate request is denied.

The Test Period in this GRC also matches the test period used in the development of the NPC filed in the 2027 TAM.

Q. Please explain how the company developed the revenue requirement for the Test Period.

A. Revenue requirement preparation began with historical accounting information; in this case, the company used the 12 months ended June 30, 2025 (Base Period). Each of the revenue requirement components in the Base Period was analyzed to determine if a normalizing ratemaking adjustment was warranted to reflect normal operating conditions. The historical information was then adjusted to recognize known, measurable, and anticipated events. Previous Public Utility Commission of Oregon (Commission)-ordered adjustments are also included as part of the company's revenue requirement calculation for the Test Period.

Q. What is the significance of beginning with historical information?

A. The company begins with historical accounting information and makes discrete adjustments to arrive at the Test Period revenue requirement. Beginning with historical information provides a solid foundation that is readily available for audit. Individual adjustments are also available for review, such that regulators and intervenors may determine each adjustment's relevance and accuracy.

Q. Please summarize the process used to adjust the historical accounting information to reflect Test Period revenues and costs.

A. Revenues are adjusted by applying the current Commission-approved tariff rates to the Test Period load projection. NPC are developed using the Aurora model from Energy Exemplar. The results of the Aurora run for the Test Period are embedded in

the results for calculation purposes only; as previously mentioned, recovery of these costs is sought through the 2027 TAM filing. Historical operations and maintenance (O&M) expenses, excluding NPC, are split into labor and non-labor components. Non-labor costs are adjusted for inflation using inflation indices developed specifically for electric utilities provided by S&P Market Intelligence (previously IHS Markit) and for other distinct changes required to reflect conditions expected during the Test Period. Historical labor costs are also adjusted for contractual and anticipated increases through the end of the Test Period.

Q. Does the company rely solely on its own projections of future cost increases?

A. No. For example, the adjustment made to account for inflation between the historical period and the Test Period relies on inflation indices published by S&P Market Intelligence. Updates to pension and benefits expenses are made in accordance with forecasts from actuarial reports, while labor expenses governed by union contracts are walked forward to Test Period levels using contractual labor increase percentages.

Q. How has the company addressed areas where cost variances are expected to be different than inflation?

A. The company's business units were asked to identify areas where budgets were significantly different than historical amounts, adjusted for wage increases and inflation. When differences were identified, the business units were asked to provide support for changes in the number, or frequency, of activities. An example of this type of adjustment is the Wildfire Mitigation and Vegetation Management Expenses adjustment (adjustment page 4.11). Adjustments of this nature are necessary because

inflation indices account for cost increases on existing units of production, not changes in volume or processes.

Q. Has the calculation of federal income tax expense been changed since the last GRC?

A. No. Federal income tax expense for ratemaking is calculated using the same methodology that the company uses in preparing its filed income tax returns. As with the previous GRC, for the calculation of revenue requirement the federal income tax rate is reflected at 21 percent, which represents the current enacted federal income tax rate.

Q. Are changes being proposed to depreciable lives in this case?

A. No. This filing reflects Test Period depreciation expense in the company's revenue requirement that is calculated generally based on depreciation rates approved in the 2018 Depreciation Study.[5] The company has also incorporated approved incremental depreciation changes in accordance with revisions to the end of depreciation lives for several thermal generation units as approved in the final orders of the company's 2023 GRC, docket UE 399[6], and the company's 2025 GRC, docket UE 433, respectively.

Q. How has the company treated forecast capital additions to electric plant in-service (EPIS) in this filing?

A. The company is proposing interim rates 30 days from filing with a final rate effective date for this GRC of July 15, 2027. However, if interim rates are not authorized, the

[5] *In the Matter of PacifiCorp dba Pacific Power Application for Authority to Implement Revised Depreciation Rates*, Docket No. UM 1968, Application (Sept. 13, 2018).
[6] *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).

company proposes that the rate effective date of this GRC be April 5, 2027. Accordingly, the company has only included capital additions to plant in-service through March 31, 2027, for the purpose of calculating the Test Period EPIS balance in this case. This treatment of including capital additions up through the rate effective date is consistent with the company's 2011,[7] 2013,[8] 2014,[9] 2021,[10] 2023[11] and 2025[12] GRCs. Additionally, as in docket UE 433, the company has excluded all forecast capital projects eligible for recovery under the WMPA AAC from the forecasted list of capital in the Test Period results of this filing.

Q. Has the company proposed an EPIS rate base methodology that is different than the one used in the last GRC in response to the Commission's order from docket UE 433?[13]

A. Yes. In this GRC, for test period calendar year 2027, the company is proposing to include in its EPIS rate base capital additions anticipated to be placed in-service through March 31, 2027, and gross plant balances will be reflected on a simple thirteen-month average (13 MA) basis through the end of the Test Period. Depreciation and amortization expenses are walked forward through the end of the Test Period, and accumulated reserves are also correspondingly reflected on a simple

[7] *See In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 217, Order No. 10-473 (Dec. 14, 2010).
[8] *See In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 (Dec. 20, 2012).
[9] *See In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 263, Order No. 13-474 (Dec. 18, 2013).
[10] *See In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 (Dec. 18, 2020).
[11] *See 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).
[12] *See In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 433, Order No. 24-447.
[13] See Order No. 24-447 at 77, "…we expect PacifiCorp to propose a different methodology for calculating its [electric plant in-service] rate base that better balances regulatory lag in its next general rate case."

13 MA basis through the Test Period. All rate base balances (i.e. plant and non-plant) are consistently established on a simple 13 MA basis through the end of the Test Period, although the plant balance does not include new capital placed in-service after March 31, 2027.

Q. Can you briefly summarize the EPIS rate base methodology issues in docket UE 433?

A. Yes. In the company's 2025 GRC, docket UE 433, PacifiCorp calculated EPIS rate base using the same methodology that had been approved for ratemaking since docket UE 217, which used a calendar year 2011 test period. Under this longstanding approach, test period EPIS and accumulated reserve balances were established on an end-of-period basis immediately before the requested rate effective date, with an annualized depreciation and amortization expense adjustment and a corresponding adjustment to accumulated reserves to match that annualized expense. Although PacifiCorp had relied upon this EPIS rate base methodology for almost fifteen years, during which multiple GRCs had been decided including a fully litigated GRC in docket UE 374, Commission Staff opposed this methodology in docket UE 433 and instead recommended walking accumulated reserves through the end of the test period, without adding matching incremental capital additions after the rate effective date, and then applying an average-of-monthly-averages approach.

In Order No. 24-447, the Commission declined to adopt Staff's average-of-monthly-averages proposal. The Commission explained that "there remain too many questions about the impact of such a large change," but also directed that, going

forward, PacifiCorp should propose a rate base methodology that "better balances regulatory lag in its next general rate case."[14]

Q. In what ways does the proposed rate base methodology differ from the methodology used in docket UE 433 and prior?

A. Table 2 below provides a comparative view between the EPIS rate base methodology used in the company's prior GRC, and the methodology used in the current GRC.

Table 2 – Comparison of EPIS Rate Base Methodologies

	2025 GRC (UE 433)	2027 GRC
Test Period	Calendar Year 2025	Calendar Year 2027
Capital Additions Cut-off	December 31, 2024	March 31, 2027
EPIS Balance	End-of-period December 31, 2024	13 MA December 2027
Depreciation Expense	Annualized based on capital additions through 2024	Forecasted for January - December 31, 2027
Accumulated Reserves	End-of-period December 31, 2024, with annualization adjustment	13 MA December 2027

Q. How is the proposed EPIS rate base methodology in this GRC an improvement to the methodology previously used?

A. In docket UE 433, Commission Staff raised two primary concerns with the company's EPIS rate base methodology. First, Staff characterized the docket UE 433 approach as a "Pre-Test Period Snapshot" methodology, which they argued created a mismatch between costs and benefits—specifically, accumulated reserves were valued at the mid-point of the test period while EPIS balances remained at beginning-of-period levels. Second, Staff asserted that this Pre-Test Period Snapshot

[14] *Id.*

approach departed from longstanding Oregon precedent favoring an averaging methodology for calculating EPIS rate base.

The methodology proposed in this GRC addresses both concerns. Under this new approach, EPIS rate base and accumulated reserves are each calculated using a 13 MA through the Test Period, ensuring that depreciation-related costs and benefits are aligned. Customer rates therefore no longer rely on a single "snapshot" in time. This 13 MA methodology also aligns with Oregon's historical preference for averaging EPIS rate base, while avoiding the complexity of the average-of-monthly-averages methodology proposed by Staff in docket UE 433. Additionally, because capital additions are included through three months into the Test Period—rather than cutting off before the Test Period begins—this method better balances regulatory lag while remaining consistent with ORS 757.355, and continuing to reflect the decline in net plant from Test Period depreciation.

A further improvement is that all rate base components—plant and non-plant—are now consistently calculated using the same simple 13 MA methodology. Previously, EPIS balances were determined using an end-of-period approach with annualization, while non-EPIS components used a 13 MA. The proposed methodology in this GRC provides a synchronized, more transparent, and more consistent rate base calculation.

Q. What components related to wildfire mitigation and vegetation management are included in the revenue requirement in this case?

A. Oregon wildfire mitigation capital and wildfire mitigation O&M expenses that are eligible for recovery through the WMP AAC are not included in calculation of base

rates in this filing. However, system wildfire mitigation investments that are located outside of Oregon, for which costs are allocated into Oregon's rates, are included in this case.

Vegetation management O&M is reflected in the Test Period at $61 million, which is a reduction from the current level of $67 million approved in rates through Order No. 24-447, in docket UE 433.

IV. INTER-JURISDICTIONAL ALLOCATIONS

Q. What methodology is the company using to calculate the Oregon-allocated revenue requirement in this case?

A. As discussed in the testimony of witness Link, the company's Oregon-allocated revenue requirement continues to be calculated using the 2020 Inter-Jurisdictional Allocation Protocol (2020 Protocol), which was initially approved by the Commission in docket UM 1050 on January 23, 2020, and further approved for use to jurisdictionally allocate revenue requirement in Oregon rates through the end of 2025 on June 27, 2023.[15] While the 2020 Protocol expired at the end of 2025, it is the most recent allocation methodology approved by the Commission, and was used to set current rates. The company proposes the continued use of the 2020 Protocol for ratemaking purposes until a new allocation methodology is approved.

V. OREGON RESULTS OF OPERATIONS

Q. Please describe Exhibit PAC/802.

A. Exhibit PAC/802, which was prepared under my direction, is the company's Oregon

[15] *See In the Matter of PacifiCorp dba Pacific Power, Petition for Approval of the 2020 Inter-Jurisdictional Allocation Protocol, Docket No. UM 1050*, Order No. 20-024 (Jan. 23, 2020); *See In the Matter of PacifiCorp dba Pacific Power, Petition for Approval of the 2020 Inter-Jurisdictional Allocation Protocol, Docket No. UM 1050*, Order No. 23-229 (Jun. 30, 2023).

results of operations report (Report). As previously explained, the Base Period for the Report is the 12 months ended June 30, 2025, which has been normalized and used to calculate the revenue requirement for the Test Period, the 12 months ending December 31, 2027. The Report provides totals for revenue, expenses, depreciation, NPC, taxes, rate base, and loads in the Test Period. The Report presents operating results for the Test Period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit PAC/802 is organized.

A. The Report is organized into sections marked with tabs as follows:

- Tab 1 Summary contains a summary of Oregon-allocated results according to the 2020 Protocol. Page 1.1 breaks out the non-NPC results and calculates the revenue increase the company is requesting as part of this GRC (column 5). Page 1.2 contains a summary of the GRC request.
- Tab 2 Results of Operations details the company's overall revenue requirement, showing unadjusted costs for the Base Period and fully normalized results of operations for the Test Period by FERC account and 2020 Protocol allocation factor.
- Tabs 3 through 8 provide supporting documentation for the normalizing adjustments required to reflect on-going costs of the company.
- Tab 9 provides the derivation of the ECD included in this case.
- Tab 10 contains the calculation of the 2020 Protocol allocation factors. Factors in this case are based on the load forecast through December 2027 and pro forma account balances.

- Tabs B1 through B20 contain the historical data for the Base Period and are organized by major FERC function.

A. <u>Tab 3 – Revenue Adjustments</u>

Q. Please describe the information contained within Tab 3 Revenue Adjustments.

A. Tab 3 begins with the Revenue Adjustment Index which contains a brief overview of the assumptions used to project Test Period revenues and a list of each normalization adjustment included in this section of the exhibit. The numerical summary (page 3.0.2) identifies each adjustment made to actual revenues and each adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a description of the adjustment.

Q. Please describe each adjustment made to revenue in Tab 3.

A. **Pro Forma Revenues (page 3.1) –** This adjustment normalizes general business revenues by adjusting to the pro forma revenue level for the Test Period based on forecasted loads. Page 3.1.4 shows a breakout of the TAM and general rate case revenues.

Confidential Renewable Energy Certificate (REC) Revenues (page 3.2) – This adjustment removes all REC revenue and REC deferrals booked during the 12 months ended June 2025. Most of Oregon's share of RECs is banked for compliance; however, not all RECs meet the Oregon Renewable Portfolio Standard (RPS) qualifications. Oregon's revenue from RPS ineligible RECs that are sold is passed back to customers through the Oregon property sales balancing account per

Commission Order No. 10-210 in docket UP 260.[16] REC revenues received through Schedule 272 are also added back into Test Year results on a forecast basis.

Wheeling Revenue (page 3.3) – This adjustment reflects the level of wheeling revenue for the Test Period by adjusting the actual revenue for normalizing, annualizing, and pro forma changes.

B. <u>Tab 4 – O&M Adjustments</u>

Q. Please describe the information contained behind Tab 4 O&M Adjustments.

A. Tab 4 includes an O&M Expense Adjustment Index followed by a numerical summary and the specific adjustments. The O&M Expense Adjustment Index begins on page 4.0.1 with a brief overview of assumptions used to adjust operations, maintenance, administrative, and general expenses. The numerical summary (pages 4.0.2 to 4.0.3) identifies each adjustment made to actual expenses and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments made to O&M expense in Tab 4.

A. **Miscellaneous General Expense and Revenue (page 4.1)** – This adjustment removes certain miscellaneous expenses that should have been charged below the line to non-regulated expenses and recognizes revenues from the Oregon Direct Access

[16] *In the matter of PacifiCorp, dba Pacific Power Application Approval of Sale of Renewable Energy Credits*, Docket No. UP 260, Order No. 10-210 (Jun. 9, 2010).

Opt Out amortization.[17] It also reallocates certain gains and losses on property sales and regulatory expenses to reflect the appropriate allocation.

Wage and Employee Benefits (page 4.2) – Labor-related costs for the Test Period are computed by adjusting salaries, incentives, health benefits, and costs associated with pension, post-retirement benefits, and post-employment benefits for changes expected beyond the actual costs experienced in the period ended June 2025.

Collective bargaining agreements are used to escalate union wages where increases are specified,[18] while increases for non-union and exempt employees were based on actual or anticipated increases. Increases are applied to the wages for each employee group according to specified or anticipated timelines to arrive at the test year wages and salaries. The specificity of the company's wage escalation is important as PacifiCorp has nine collective bargaining agreements across six unions of various sizes. Incentive compensation for non-union employees is included based on the company's forecast of test year expense, adjusted to remove 100 percent of Named Executive Officers' (NEO) share, and 50 percent of non-NEO incentives. Pension-related service expense and other employee benefit costs are adjusted to the planned expense levels for the Test Period, based on actuarial reports, where available, or by escalating actual costs. Pension-related non-service expenses are reflected in adjustment 4.3, described in the following subsection.

[17] *In the matter of PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 at 6 (Feb. 24, 2015).

[18] Where union contracts have not yet been finalized for increases that would become effective within the Test Period, an estimated escalation percentage is applied. Actual increases for these unions will be updated as more information becomes available during the pendency of this case.

Page 4.2.5 of the Report provides further description of the procedures used to compute Test Period labor costs. Page 4.2.6 contains a numerical summary of actual labor costs in the year ended June 2025 and summarizes the adjustments made to project costs through the Test Period. This summary is followed by detailed worksheets on pages 4.2.7 through 4.2.14.

Pension-Related Non-Service Expense (page 4.3) – This adjustment reflects in the Test Period non-service pension and post-retirement expense at anticipated 2027 levels. These expenses were historically included in the company's results of operations reports in the Wage and Employee Benefits adjustments. However, because these expenses are no longer eligible for capitalization under generally accepted accounting principles and are therefore not included in the company's capitalization calculations, they have been accounted for in a separate adjustment since the 2023 GRC. All other pension-related service expenses continue to be included in the Wage and Employee Benefits adjustment. Also consistent with the approved outcome in the company's most recently approved GRCs since docket UE 399, pension settlement losses in this case are being amortized over the approximately 20-year average remaining life expectancy of plan participants.

Remove Non-Recurring Entries (page 4.4) – This adjustment removes an accounting entry made to an expense account during the Base Period that is non-recurring in nature. Accordingly, the transaction amount is removed to normalize Test Period results. Details on the specific item in the adjustment can be found on Page 4.4.1.

Insurance Expense (page 4.5) – In the 2010 GRC, the Commission authorized the company to establish monthly accruals and associated reserve balances for self-insurance for transmission and distribution property losses, non-transmission and distribution (Non-T&D) property losses, and third-party liability losses.[19] The Commission ordered the accrual to begin on April 1, 2011, as a replacement for the expiration of the company's captive insurance coverage with Berkshire Hathaway Energy Company (BHE), formerly known as MidAmerican Energy Holdings Company. The Oregon-allocated monthly accrual for property related losses was based on a 10-year average of actual property losses, with each year escalated by the Consumer Price Index to the Test Period. The Oregon-allocated monthly accrual for third-party liability losses was established based on an annual average of historical insurance claims payments from April 2005 to December 2009.

In this GRC, the company is proposing to use a three-year average of property damage expense to establish its self-insurance reserve accrual, calculated using the most recent three-year time period. Actual property damage expenses have outpaced the annual accrual amounts in recent years. This has been a persistent situation causing the self-insurance reserve account to revert from a credit balance (reduction) in rate base as intended, into a debit balance (addition) in rate base. This balance represents costs that Oregon customers have been underpaying in property damage expenses, relative to actual property damages expenses the company has incurred. To address this under recovery of property damage expenses in the Oregon property insurance reserve balance, the company was authorized to include in rates the 10-year

[19] Order No. 10-473 at 5.

amortization of the unrecovered balance in its 2023 GRC. At that time, the balance of unrecovered property damages expenses was just over $20.9 million. Despite this amortization of the unrecovered Oregon property insurance reserves balance, as of June 2025, the company is faced with a debit balance of $48.7 million accumulated in this account, due to increased restoration expenses as a result of the frequency and severity of storms experienced in PacifiCorp's service territory. The annual expenses for property-related losses have been trending up, and a 10-year historical average, as initially adopted in 2011, is not sufficient to keep pace with actual expense levels in more recent years. To address the shortfall in the reserve account, PacifiCorp is proposing to shorten the time-frame over which the historical average is calculated in order to establish an on-going annual property loss reserve accrual amount using more recent levels of actual expenses, such that the annual accruals be established at a level that more sufficiently covers actual property loss expenses.

For the self-insured retention third-party liability accrual, the company continues to calculate accruals in rates based on a three-year average of historical gross expense, net of insurance proceeds, using the cash method, for the most recent three-year time period, as approved in docket UE 433. As with the approved outcome in docket UE 433, the company has calculated a three-year average accrual level that excludes payments for significant wildfire events.

In addition to the self-insured amounts described above, PacifiCorp maintains multiple lines of insurance coverage, including, but not limited to the following:

<u>Excess Liability</u>

Claims-made excess liability policies provide coverage for third-party legal liability arising from bodily injury and property damage claims in excess of the company's self-insured retention of $10 million per occurrence. The total limit for non-wildfire

liability coverage is $552.5 million. Coverage for wildfire-related liability arising from the company's operations in Oregon and Washington with a limit up to $130 million and California with a limit up to $75 million, as well as coverage for third-party legal liability arising from property damage-only claims in excess of $250 million per occurrence with a limit up to $100 million. The total available wildfire insurance limits are up to $230m in Oregon and Washington and up to $175m in California.

Punitive Damages
Provides indemnity-only excess liability coverage for punitive damages imposed or award against the insured under certain circumstances specified in the policy.

Onshore Property
Provides all-risk coverage for physical loss or damage to operating locations, including terrorism, fire, earthquake, flood, theft, boiler and machinery breakdown, and turbine generator breakdown. The coverage also includes certain ancillary protections, such as increased cost of construction, incidental transit, service interruption, debris removal, accounts receivable, and firefighting equipment. Coverage applies to losses in excess of the company's $10 million self-insured retention, subject to a $400 million per-occurrence limit.

Inland Transit and Storage
Coverage is included for BHE transits of turbine rotors, generators, combustion components, exciters, and similar machinery and equipment. Allocation is based on the values of the property shipped.

Wind and Solar Equipment Storage
Provides property coverage for wind and solar equipment in storage. Allocation is based on the values of the property in storage.

Large-Deductible Worker's Compensation
Provides statutory coverage once the deductible is met for employees injured directly as a result of their employment with the company.

Excess Workers Compensation
Provides statutory coverage in excess of self-insured retention for employees injured directly as a result of their employment with the company.

Automobile Liability
Coverage for third-party bodily injury and property damage liability arising out of automobile accidents that are BHE's fault. This covers liability arising out of the use of owned, non-owned, and hired automobiles. Coverage does not include physical damage.

Aviation and Unmanned Aircraft Systems
Provides liability for bodily injury and property damage to third parties arising out

of the use of owned and non-owned aircraft. The policy also includes physical damage loss to aircraft as well as war and terrorism and sabotage buyback purchases for both liability and physical damage. Each aircraft is individually rated, and charges are sent to the business which owns the aircraft.

Executive Protection Liability
Provides risk management and crisis-response services to protect individuals and organizations from kidnapping, extortion, and wrongful detention, including risk assessment, negotiation support, evacuation, and insurance coordination.

Fiduciary Liability
Provides coverage for loss caused by claims related to their responsibilities and obligations as defined by the Employee Retirement Income Security Act of 1974 and in the administration of any plan.

Crime
Provides coverage for loss due to dishonest acts of employees, burglary, robbery, funds transfer fraud, and computer crimes. Losses may also arise from embezzlement, theft of inventory, false invoices, and kickbacks.

Surety Bonds
Used to evidence the company's ability to pay its contractual or compliance-related financial obligations. Surety companies issue bonds to obligees in the amount of the obligation, thereby guaranteeing that the company will perform its duties.

Total-company non-T&D property insurance premiums were $6.7 million for the 12 months ended June 2025, and have reduced slightly to $6.0 million for the Test Period. This reflects the renewal amounts effective February 2026, which is the best-known information at this time.

Total-company liability insurance premiums were approximately $177.8 million for the 12 months ended June 2025. Net expense of $127.2 million was recorded on PacifiCorp's books reflecting state specific deferrals recorded during this same timeframe, which would typically be removed for purposes of setting rates in a GRC. However, the company is completely removing the expenses recorded in the Base Period and replacing them with premiums for new liability policies effective in February and March 2026. These policy renewals resulted in a combination of

policies that provide coverage for PacifiCorp as a system, and wildfire insurance policies that cover PacifiCorp's three western jurisdictions (California, Oregon and Washington). Wildfire liability premiums for policies that only cover Oregon, Washington and California have been allocated proportionately using each state's System Overhead allocation factor. The total excess liability insurance premiums allocated to Oregon for these policies are approximately $49.1 million and reflect the best available information for the Test Period.

Generation Overhaul Expense (page 4.6) – This adjustment normalizes generation overhaul expenses in the Base Period using a four-year average methodology. In this adjustment, overhaul expenses for the years ending June 2022 to June 2025 are restated to constant dollars to make them comparable prior to averaging.

Revenue-Sensitive Items & Uncollectible Accounts (page 4.7) – 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. This adjustment also reflects pro forma changes to Franchise Tax, Resource Supplier Tax, and Public Utility Commission Fees based on the normalized level of general business revenue for the Test Period. Franchise Tax and Resource Supplier Tax is calculated based on three-year historical average tax factors as approved in docket UE 374 GRC, and subsequently also adopted in customer rates approved in dockets UE 399 and UE 433. The Public Utility Commission Fee is calculated using the most recently approved rate of 0.36 percent,

as established by Order No. 26-043 in docket UM 1012.[20] Should further updated inputs become available for the calculation of revenue sensitive items in this GRC, the company will update its calculation as part of the compliance filing made to implement approved rate changes in this case to reflect the most recently approved inputs once it becomes available.

Memberships and Subscriptions (page 4.8) – This adjustment removes expenses in excess of Commission policy as outlined by the Commission order in docket UE 94.[21] National and regional trade organizations are recognized at 75 percent. This adjustment also removes memberships in chambers of commerce and other economic development organizations in accordance with Order No. 24-447 in docket UE 433.

Meals and Entertainment Adjustment (page 4.9) – This adjustment reflects a 50 percent sharing provision on expense categories identified in Order No. 20-473 (docket UE 374) and Order No. 24-447 (docket UE 433) respectively as discretionary and should be shared between customers and shareholders according to Commission policy. These expenses include meals and entertainment, awards, on-site meals & refreshments, catering services, and coffee/water/beverage services.

O&M Escalation (page 4.10) – This adjustment increases non-labor expenses for projected inflation through the Test Period. Projected increases or decreases in costs are based on S&P Market Intelligence Power Planner (Power Planner) indices, which provide a detailed assessment of the electric market both historically and into the future. The indices used are based solely on electric utility costs for materials and

[20] *In the matter of Public Utility Commission of Oregon, the Imposition of Annual Regulatory Fees Upon Public Utilities Operating within the State of Oregon*, Docket No. UM 1012, Order No. 26-043 (Feb. 17, 2026).
[21] *In the matter of the Petition of PacifiCorp to Amend Order No. 98-191 Regarding Annual System Benefit Charge Adjustment*, Docket No. UE 94, Order No. 01-502 (June 22, 2001).

services, which exclude labor expense, according to the Uniform System of Accounts defined by FERC for major electric utilities. Use of the Power Planer indices for escalation of non-labor O&M expenses is consistent with the company's past rate cases, including its 2025 GRC in which the Commission approved a revenue requirement calculated using these indices.

The Power Planner indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. The individual FERC account level indices are then combined into broader indices representing operation, maintenance, or total O&M expenses. The S&P Market Intelligence study used to prepare this filing was the fourth quarter 2025 forecast, released January 23, 2026. The S&P Market Intelligence data is proprietary and subject to copyright protection, therefore the indices utilized in the company's case are provided in Confidential Exhibit PAC/805.

Vegetation and Wildfire Management O&M (page 4.11) – This adjustment removes wildfire mitigation and vegetation management expenses recorded in the Base Period and then adds back the Test Period level of non-wildfire vegetation management expense forecasted for calendar year 2027. Test Period vegetation management expense has been established at $61 million, which is a reduction from levels established in the company's 2025 GRC. Wildfire mitigation expenses in Oregon[22] that are expected to be recoverable under the WMP AAC, as allowed in the

[22] Oregon WMP costs include only Oregon distribution costs, and Oregon's allocation of transmission costs for WMP activities located inside Oregon, per Docket No. ADV 1529 settlement agreement. Transmission costs for WMP work performed in other states continues to be allocated to Oregon at the system generation (SG) allocation percentage and is recovered through the GRC.

docket ADV 1529 settlement agreement, are not included in base rates revenue requirement calculations in this filing.

Customer Payment Fees (page 4.12) – Per docket UE 433, Order No. 24-447, the Commission supported the elimination of payment fees for residential customers effective January 1, 2025, to make payment easier and to eliminate a barrier for vulnerable customers. This adjustment walks forward the actual customer payment fees recorded in the 12 months ended June 2025 to the test period levels as approved in docket UE 433.

C. <u>Tab 5 – NPC Adjustments</u>

Q. Please describe the information contained behind Tab 5 NPC Adjustments.

A. Tab 5 includes adjustments to items that are generally related to NPC, most of which are addressed separately in the company's TAM filing. Specifically, adjustment page 5.1, NPC Adjustment, relates solely to NPC and recovery of these costs is being sought in the TAM rather than the GRC. This adjustment is included for modeling and computational purposes only. For example, the Test Period revenue requirement includes revenue sensitive items such as Franchise Tax, Resource Supplier Tax, and Public Utility Commission Fees that are calculated off total general business revenues, including those collected for the purpose of recovering costs included in the TAM.

The NPC Adjustment Index on page 5.0.1 is a brief overview of assumptions used to adjust NPC-related items. The numerical summary (page 5.0.2) identifies each adjustment made to actual expenses and that adjustment's impact on overall revenue requirement. Each column has a numerical reference to a corresponding page

in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 5.

A. **NPC Adjustment (page 5.1) –** This 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, as well as normal hydro and temperature conditions for the Test Period. The Aurora study for this adjustment is based on forecasted loads for the Test Period. As previously described, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; NPC is not part of the revenue requirement for the GRC.

WRAP, BOSR and COSR Material Costs (page 5.2) – This adjustment updates Test Period results for the Western Resource Adequacy Program (WRAP) fee, Energy Imbalance Market Body of State Regulators (BOSR) fee, and Committee of State Regulators material costs estimated for calendar year 2027.

D. <u>Tab 6 – Depreciation and Amortization Expense Adjustments</u>

Q. Please describe the information contained behind Tab 6 Depreciation and Amortization Adjustments.

A. Tab 6 includes the Depreciation and Amortization Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 6.0.1 is a brief overview of assumptions used to adjust overall depreciation and amortization expense and reserve. The numerical summary (page 6.0.2) identifies each adjustment made to actual results and that adjustment's impact on the case. Each

column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 6.

A. **Depreciation and Amortization Expense (page 6.1)** – This adjustment reflects the incremental depreciation expense associated with the capital additions included in Adjustment 8.5, Pro Forma Plant Additions and Retirements, and calculates the depreciation expense using the approved depreciation rates in dockets UM 1968 and UE 374, which became effective January 1, 2021. This adjustment also incrementally considers the depreciation changes to specific coal-fired generation facilities approved in dockets UE 399 and UE 433 respectively. Depreciation and amortization expense for the Test Period is calculated by applying the current composite depreciation and amortization rates to the projected monthly pro forma plant balances through the Test Period. Detailed calculations of the depreciation and amortization expense are provided on pages 6.1 through 6.1.48.

Depreciation and Amortization Reserve (page 6.2) – This adjustment steps forward the depreciation and amortization reserve from the Base Period to a Test Period 13 MA level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to Base Period balances. The monthly reserve balances are calculated to walk balances forward from June 30, 2025, to December 31, 2027. A 13 MA calculation is then performed using the 13 monthly balances from December 31, 2026, to December 31, 2027. The reserve balance calculations are detailed on pages 6.2 to 6.2.42.

Repowering Buy-Downs Adjustment (page 6.3) – As a result of the all-party stipulation in docket UE 369, the undepreciated equipment balances from repowered assets were bought down in part with the Excess Deferred Income Tax (EDIT) balances that resulted from the Tax Cut and Jobs Act, and a portion of the company's deferred FERC Open Access Transmission Tariff revenues. This adjustment brings into results the amortization expense and accumulated reserves for wind facilities buy-downs for all repowered projects and adds into results pro forma amortization to reflect expense and reserves for these balances at the appropriate Test Year levels.

Confidential Bridger Mine Reclamation and Decommissioning Cost (page 6.4) – This adjustment reflects the recovery of accelerated depreciation and reclamation costs for the Bridger Mine incremental to the amounts included in the cost of coal delivered to the Jim Bridger Plant that was initially approved in the company's 2021 GRC. These costs were approved to be recovered over the remaining depreciable life for Oregon Customers of the Jim Bridger Plant, which in the 2021 GRC was assumed to be 2025. The approved amounts collected from Oregon customers were deferred to a regulatory liability, which was going to be debited with Oregon's share of reclamation costs when the Bridger Mine closes. This treatment allowed the company to recover costs for the Bridger Mine while meeting the Senate Bill (SB) 1547 requirement of removing coal from Oregon electric utility rates prior to January 1, 2030.

Subsequently, in the company's 2025 GRC, docket UE 433, the company was ordered to extend the depreciable life of Jim Bridger Plant, specifically the coal-fired units, through 2028. Accordingly, in this GRC, the company has recalibrated the

estimated reclamation costs for the Bridger Mine to reflect on-going operations through 2028. With the extension of depreciable life, the recalibrated Bridger Mine reclamation and incremental depreciation adjustment is resulting in a net reduction to expenses in the Test Period. This credit will effectively reduce Oregon customers' allocation of Bridger Mine reclamation and depreciation expenses that are embedded in the cost of coal delivered.

Additionally, this adjustment also adds into Test Period results the incremental decommissioning and other plant closure costs for Jim Bridger Units 3 and 4, and Dave Johnston Unit 4, which were approved to be recovered over a 12-year period per Order No. 24-447 in docket UE 433.

E. <u>Tab 7 – Tax Adjustments</u>

Q. Please describe the information contained behind Tab 7 Tax Adjustments.

A. Tab 7 includes the Tax Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index (page 7.0.1) contains a brief overview of the tax adjustments included in this case. The numerical summary on pages 7.0.2 and 7.0.3 identifies each adjustment made to the various tax components and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 7.

A. **Interest True-Up (page 7.1)** – This page details the adjustment to interest expense required to synchronize the Test Period interest expense with Test Period rate base.

This is done by multiplying normalized net rate base by the company's weighted cost of debt in this case.

Property Tax Expense (page 7.2) – Property tax expense for the Test Period is computed by adjusting accruals from the Base Period for known or anticipated changes in the assessed values of the company's operating property and the corresponding effect such changes will have on property tax expense for the Test Period. For additional information on the company's property tax estimation procedures and methodologies, please refer to Confidential Exhibit PAC/804.

Production Tax Credit (PTC) (page 7.3) – The company is entitled to recognize federal income tax credits as a result of placing renewable generating plants in service. The tax credit is based on the kilowatt-hours generated by the plants, and the credit can be taken for the first 10 years of generation from qualifying property. The PTC calculation reflects the credit based on the qualifying production as modeled for the Test Period NPC study. Customers receive the benefit of the PTCs in the company's annual TAM filing. As with NPC in Adjustment 5.1, this adjustment is included for the purpose of calculating an overall revenue requirement only, more specifically as it pertains to revenue-sensitive items.

PowerTax Accumulated Deferred Income Tax (ADIT) Balance (page 7.4) – This adjustment normalizes ADIT balances to an estimated pro forma level of rate base balance consistent with proforma capital additions, which are reflected on a 13 MA basis through December 31, 2027. Additional line-item detail is included in the tax model that is provided with the company's electronic workpapers.

Pro Forma Tax Balances Adjustment (page 7.5) – This adjustment normalizes the Schedule M items, deferred tax expense and related Accumulated Deferred Income Tax balances to an estimated pro forma level of expense for the Test Period. Additional line-item detail is included in the tax model that is provided with the company's electronic work papers.

Wyoming Wind Generation Tax (page 7.6) – This adjustment normalizes the Wyoming Wind Generation Tax, which became effective January 1, 2012, into Test Period results. The Wyoming Wind Generation Tax is an excise tax levied upon production of electricity from wind resources in the state of Wyoming. The tax is levied 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 entity producing the electricity. New wind facilities are exempt from the tax for three years following the date the facility first produces electricity for sale. The tax is one dollar for each megawatt-hour (MWh) of electricity produced from wind resources at the point of interconnection with an electric transmission line.

EDIT Adjustment (page 7.7) – This adjustment walks-forward the level of protected property EDIT amortization and adjusts the rate base for the Test Period consistent with pro forma capital additions, which are reflected on a 13 MA basis through December 31, 2027.

Allowance for Funds Used During Construction (AFUDC) Equity (page 7.8) – This adjustment reflects the appropriate level of Allowance for Funds Used During Construction equity into regulated results to align the tax schedule M with regulatory

income. Per Commission Order No. 10-022, AFUDC equity in this case is included using flow-through tax treatment.[23]

Oregon Corporate Activity Tax & Metro Supportive Housing Services Tax Adjustment (page 7.9) – This adjustment adds into base rates the forecasted Oregon Corporate Activity Tax and Metro Supportive Housing Services Tax for the Test Period.

F. <u>Tab 8 – Rate Base Adjustments</u>

Q. Please describe the information contained behind Tab 8 Rate Base Adjustments.

A. Tab 8 includes the Rate Base Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 8.0.1 begins with a brief overview of assumptions used to adjust rate base components. The numerical summary (pages 8.0.2 to 8.0.4) identifies each adjustment made to actual rate base and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe each of the adjustments to the historical rate base balances.

A. **Cash Working Capital (page 8.1) –** This adjustment supports the calculation of cash working capital included in rate base based on the normalized results of operations for the Test Period. Total cash working capital is calculated by multiplying jurisdictional net lag days by the average daily cost of service. Net lag days in this case are based on a lead lag study prepared by PacifiCorp using calendar year 2022

[23] *In the matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision*, Docket No. UE 210, Order No. 10-022 (Jan. 26, 2010).

information, which was also used in the company's 2025 GRC (docket UE 433). An electronic version of the lead lag study is included as part of the company's workpapers.

Trapper Mine Rate Base (page 8.2) – The company owns a 29.14 percent interest in the Trapper Mine, which provides coal to the Craig generating plant. The normalized cost of Trapper coal includes all O&M costs but does not include a return on investment. This adjustment adds the company's portion of the Trapper Mine plant investment to the rate base and reflects net plant to recognize the depreciation of the investment over time. This adjustment also walks the reclamation liability forward to December 2027. This adjustment was stipulated to and approved in docket UE 111[24] and has been included in all Oregon rate case filings since.

Jim Bridger Mine Rate Base (page 8.3) – The company owns a two-thirds interest in the Bridger Coal Company, which supplies coal to the Jim Bridger generating plant. The company's investment in Bridger Coal Company is recorded on the books of Pacific Minerals, Inc. Because of this ownership arrangement, the coal mine investment is not included in EPIS. This adjustment is necessary to properly reflect the Bridger Coal Company investment in rate base for the company to earn a return on its investment. The normalized coal costs for Bridger Coal Company in NPC include the O&M costs of the mine but provide no return on investment. This adjustment adds the company's portion of the pro forma December 31, 2027, net

[24] *In the matter of the Revised Tariff Schedules Applicable to Electric Service Filed by PacifiCorp*, Docket No. UE 111, Order No. 00-580 (Sept. 25, 2000).

plant balance to rate base. This adjustment was stipulated to and approved in docket UE 111 and has been included in all Oregon rate case filings since.[25]

Customer Advances for Construction (page 8.4) – Customer advances were recorded in the Base Period to a corporate cost center location rather than state-specific locations. This adjustment corrects the allocation factors of customer advances.

Pro Forma Plant Additions and Retirements (page 8.5) – To reasonably represent the cost of system infrastructure required to serve customers, the company has identified capital projects that will be used and useful by March 31, 2027.

Capital additions by FERC functional category are listed on pages 8.5.37 to 8.5.49, indicating the in-service date and amount by project. This adjustment is based on plant balances through December 31, 2027, stated on a 13 MA basis. As described earlier in my testimony, accumulated depreciation reserves were also adjusted through December 31, 2027, to match the depreciation expense and retirements. Projects over $10 million (total-company basis) are described on pages 8.5.51 through 8.5.60 of the Report.

Projected capital additions associated with large energy-use customers are included in the capital additions forecast relied upon to prepare Adjustment 8.5. However, these projects are removed from Test Period results through Adjustment 8.22, further discussed below in my testimony.

Regulatory Asset and Liability Amortization (page 8.6) – This adjustment normalizes regulatory assets and liabilities to reflect expected changes through the

[25] *In the matter of the Revised Tariff Schedules Applicable to Electric Service Filed by PacifiCorp*, Docket No. UE 111, Order No. 00-580 (Sept. 25, 2000).

Test Period to balances that are currently amortizing in the Base Period. In addition to regulatory assets included in this adjustment, the company is also seeking approval to begin amortization of four deferral balances through tariff schedules, which I discuss in Section VIII of my testimony below.

Plant Held for Future Use (page 8.7) – This adjustment removes all Plant Held for Future Use assets from FERC account 105. The company is making this adjustment in compliance with Order No. 01-787.[26]

Pension and Other Post-retirement Plan Balances Removal (page 8.8) – This adjustment removes the company's net prepaid asset associated with its pension and other post-retirement welfare plans, net of associated accumulated deferred income taxes in unadjusted results. Per Order No. 15-226 in docket UM 1633, the net pension and post-retirement prepaid is not to be included in rate base for Oregon.[27]

Capitalized Incentives (page 8.9) – In docket UE 433, in response to Commission Staff's clarifications and recommendations in its direct and reply testimony, the company prepared a capitalized incentives adjustment that removed the approximate rate base subject to disallowance for NEO incentives and non-officer employees paid since 2015. The net reduction to rate base includes an estimated accumulated depreciation reserve as an offset to gross capitalized amounts calculated using the same methodology proposed by Commission Staff in docket UE 433. A corresponding reduction to annual depreciation expense is also included in the disallowance adjustment. The adjustment in this GRC reflects a consistent rate base

[26] *In the matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 116, Order No. 01-787 (Sept. 7, 2001).
[27] *In the matter of Public Utility Commission of Oregon, Investigation into Treatment of Pension Costs in Utility Rates*, Docket No. UM 1633, Order No. 15-226, 10-11 (Aug. 3, 2015).

reduction for capitalized incentives from 2015 through 2025, developed using the same methodology approved in Order No. 24-447 of docket UE 433.

Remove Rolling Hills (page 8.10) – This adjustment removes the gross plant, accumulated depreciation, and O&M amounts related to the Rolling Hills wind resource from the Base Period. Depreciation expense for Rolling Hills is removed in Adjustment 6.1, Depreciation/Amortization Expense Adjustment. This treatment is consistent with Order No. 08-548.[28]

Deer Creek Mine Adjustment (page 8.11) – Order No. 15-161 in docket UM 1712 addressed closure of the Deer Creek mine located in Utah and ruled on several issues.[29] Order No. 20-473 in the company's 2021 GRC (docket UE 374) approved for recovery of the company's deferred unrecovered plant balances and associated closure costs in a separate tariff to be amortized over three years. The same order also determined that coal lease abandonment royalty costs were to be excluded from amounts being amortized on the basis that amounts were considered preliminary, and the timing of payment was not yet certain. In the company's 2025 GRC, the company included the amount of deferred recovery royalties in its request, to be amortized over three years. This proposed amortization was approved in docket UE 433, in Order No. 24-447. The adjustment in this GRC reflects the continued amortization of the recovery royalties balance approved in docket UE 433. This adjustment otherwise removes all Deer Creek regulatory assets and closure costs that have already been

[28] *In the atter of PacifiCorp dba Pacific Power 2009 Renewable Adjustment Clause Schedule 202,* Docket No. UE 200, Order No. 08-548, at 19-21 (Nov. 14, 2008), as supplemented and corrected by Order No, 08-554 (Nov. 25, 2008).
[29] *In the matter of PacifiCorp dba Pacific Power, Application for Approval of the Deer Creek Mine Transaction*, Docket No. UM 1712, Order No. 15-161 (May 27, 2015).

previously approved for amortization, from Base Period results, as initial amounts approved for amortization in docket UE 374 are now fully amortized.

Emissions Control Investment Adjustment (page 8.12) – This adjustment reflects in results rate base and return disallowances on emissions control investments as ordered in Order No. 20-473 in docket UE 374. This adjustment was prepared in the same manner as was included in the company's compliance filing in the 2021 GRC, and also as filed and approved in the 2023 GRC, and 2025 GRC.

Transmission Project Adjustment (page 8.13) – This adjustment reflects in results project cost disallowances on specific transmission projects as ordered in Order No. 20-473 in docket UE 374. Also included in this adjustment is the ordered exclusion of specific wildfire mitigation investments on PacifiCorp's transmission system in accordance with Order No. 24-447.[30]

Cholla Unit 4 Retirement (page 8.14) – Cholla Unit 4 ceased operations December 31, 2020. As part of the 2021 GRC, the company's proposal to buy down the undepreciated plant balance and closure costs using Tax Cuts and Jobs Act deferred tax benefits was approved. Subsequently, in its 2023 GRC, the company sought recovery of additional closure cost items associated with the Cholla Unit 4 closure for which amounts were not included as part of the 2021 GRC, as the amounts were yet unknown when that GRC was prepared. The recovery request for incremental Cholla Unit 4 closure costs in the 2023 GRC included amortization of deferred property tax costs associated with Cholla Unit 4, deferred safe harbor lease termination payment and non-union severance expenses over three years. In Order No. 22-491, the

[30] Order No. 24-447, Docket No. UE 433, page 28.

company was ultimately approved to amortize the deferred property taxes related to Cholla Unit 4 through the closure process in a separate tariff rider, but the amortization of the remaining Cholla Unit 4 closure costs as requested in the 2023 GRC remained in base rates. Amortization of amounts remaining in base rates began January 1, 2023, and was approved for an amortization period of three years. As of the end of 2025, the deferred costs in base rates have been fully amortized. Accordingly, this adjustment removes all regulatory assets, and amortization amounts from Base Period results.

Miscellaneous Rate Base (page 8.15) – This adjustment reflects the change in the fuel stock balance from the Base Period to the Test Period. This adjustment also reflects the working capital deposits that are offsets to fuel stock costs. In addition, balances for prepaid overhauls at the Lake Side, Chehalis, and Currant Creek natural gas plants are walked forward to reflect payments and transfers of capital to electric plant in service on a 13-month average basis through the Test Period. This adjustment was included in the stipulated settlement and approved in the company's 2013 GRC and has been included in every rate case since.[31] For further discussion supporting the company's projected fuel stock balance for the Test Period, please refer to the direct testimony of company witness Jayson D. Branch.

Carbon Plant Closure (page 8.16) – The Carbon plant was retired in April 2015. In the 2021 GRC, amortization of Oregon's excess decommissioning reserve, net of Oregon's allocation of Carbon's obsolete materials and supplies inventory, over five years was approved. As of the end of 2025, this balance is fully amortized. This

[31] Order No. 13-474 at 3 and App. A at 18.

adjustment removes any residual balances related to the Carbon plant net amortizations from Test Period results.

Removal of Wildfire Mitigation Capital Rate Base (page 8.17) – As implemented and adopted in docket UE 433, all Oregon wildfire mitigation costs recoverable under the WMP AAC, both O&M and capital costs, are being removed from base rates in this filing to be recovered in the WMP AAC. This adjustment removes all Oregon WMP AAC recovery-eligible wildfire mitigation capital costs in rate base from the Test Period. The removal of associated depreciation expense for assets removed is also reflected in this adjustment.

Dave Johnston Unit 4 Repairs (page 8.18) – The company experienced a fire at Unit 4 of the Dave Johnston plant in 2025, with repairs expected to occur during 2026. The company anticipates that the majority of repair costs will be covered by property insurance, except for amounts associated with the $10 million deductible. Accordingly, the company includes $10 million in the Test Period for the portion of repair capital expected to be placed in service. This adjustment also incorporates the related depreciation expense and reserve amounts, as well as the retirement of assets damaged due to the fire.

Klamath Regulatory Asset (page 8.19) – PacifiCorp is a signatory to the Klamath Hydroelectric Settlement Agreement, which provides for the transfer of four main-stem Klamath Hydroelectric Project developments, previously licensed to PacifiCorp, to a third-party dam removal entity that will pursue their removal. The Lower Klamath hydroelectric generation assets were transferred to the Klamath River Renewal Corporation for final decommissioning in December 2022. At the time of

transfer, the remaining net plant balance was initially reclassified from hydro plant to intangible plant as PacifiCorp continued to generate electricity for customers. The company continued to assume depreciation on the intangible plant assets using a 20 percent rate (i.e. five years depreciable life), consistent with the depreciation rate for Klamath assets approved in docket UE 374. A subsequent determination from FERC denied the company's inclusion of the balance as intangible plant, and so the balance was then reclassified as a regulatory asset. The company continued to amortize this balance, now classified as a regulatory asset, assuming the five years' amortization life previously established for Klamath assets at the end of 2022. In its 2025 GRC, the company's proposal to remove the regulatory asset from rate base, and instead accrue interest on the balance at the Modified Blended Treasury Rate, with rates effective January 1, 2025, and to continue amortization of the balance through 2027 was adopted. This adjustment walks forward the amortization amounts through the Test Period, and removes the rate base balance from Test Period results, consistent with the outcome of the 2025 GRC. Also, this adjustment removes residual O&M expenses from the Base Period associated with Klamath hydroelectric facilities operations.

Confidential New Wind Generation Capital Additions (page 8.20) – This confidential pro forma adjustment adds into Test Period results the capital addition and depreciation amounts for new wind generation projects placed in-service after the Base Period, through March 2027. The majority of the capital amounts in this adjustment are currently being recovered through PacifiCorp's RAC, which will be set to zero coinciding with rate effective date of the GRC.

Craig Unit 1 Retirement (page 8.21) – Docket UE 374 established an Exit Date of December 31, 2025, for Craig Unit 1, which was also originally scheduled to retire on December 31, 2025. However, the company received a ninety-day emergency executive order from the U.S. Department of Energy requiring the unit to remain available for generation, with the order renewable in successive ninety-day periods. As a result, the company will continue depreciating the plant through the end of 2026 to further build the accumulated depreciation reserve needed for future decommissioning. This treatment is reflected in the Depreciation and Amortization Reserve adjustment (Page 6.2). Adjustment 8.21 removes the gross plant balance, associated operations and maintenance expenses, and depreciation expense from the Test Period to appropriately account for the unit's planned retirement.

Remove Large Energy-Use Facilities (page 8.22) – This adjustment removes from Test Period results capital projects associated with large energy-use facilities as defined under House Bill 3546 (the POWER Act), that were included the Test Period forecast used to develop Adjustment 8.5 – Pro Forma Plant Additions and Retirement Adjustment.

Q. Has the company included any adjustments to non-fuel material and supplies (M&S) rate base in this case?

A. No.

Q. Does the company historically include adjustments to non-fuel material and supplies (M&S) rate base in GRCs?

A. No. The only instance when an adjustment was included for non-fuel M&S rate base in revenue requirement was in the compliance filing for docket UE 433, where the

Commission adopted a three-year historical average (adjusted for inflation) rate base adjustment for non-fuel M&S rate base proposed by Commission Staff. Except for this one instance, non-fuel M&S balance has historically been established for ratemaking purposes using the Base Period actual balance. In other words, no pro forma adjustments are historically made to non-fuel M&S rate base in GRCs.

Q. Why has a three-year historical averaging adjustment not been prepared for non-fuel M&S in this case?

A. The company maintains that a three-year historical averaging of a singular rate base component is inappropriate. 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 serving customers. Also, M&S is procured in accordance with the anticipated needs in the upcoming operational periods, and would also fluctuate with procurement costs, as prices of M&S change over time due to inflation and supply and demand. For these reasons, reverting to a historical rate base balance to determine on-going levels in a GRC is not appropriate.

Q. Can you provide evidence to support this?

A. Yes. Please refer to Table 3 below. Line 1 of Table 3 presents a three-year historical average, adjusted for inflation, of non-fuel M&S balances for calendar years 2019 through 2024, on an Oregon-allocated basis. Line 2 of Table 3 presents the actual reported, Oregon-allocated, non-fuel M&S balances reported in each annual results of operations filed in Oregon for calendar years 2019 through 2024. Line 3 compares the actual balance (Line 2) to the prior year historical average (Line 1) balance. Finally,

Line 4 compares the actual balance (Line 2) to the actual (Line 2, prior year) balance from the prior calendar year.

Table 3 – Non-Fuel M&S Balances

	Oregon Allocated ($)						
	Non-Fuel M&S	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
1	**Historical Average**	72,274,354	77,170,047	82,614,227	93,730,142	109,245,545	139,803,820
2	**Reported Actual**	75,164,881	81,398,084	83,786,381	98,759,483	130,418,627	179,603,179
	Variance Comparison		**2020**	**2021**	**2022**	**2023**	**2024**
3	**Current Year Actual vs. Prior Year Historical Average**		(9,123,730)	(6,616,334)	(16,145,256)	(36,688,485)	(70,357,634)
4	**Current Year Actual vs. Prior Year Reported Actual**		(6,233,203)	(2,388,297)	(14,973,102)	(31,659,144)	(49,184,552)

While both prior year actual and prior period's historical averages are lower than the current year actual reported balance for all years compared, the variance when comparing current year actual balances to prior period's historical average balances is by far much larger than the comparison between current year actual balance, and prior year's actual balance. This is evident in the fact that the variance presented in Line 3 of Table 3 is consistently higher than the variance presented in Line 4 of Table 3 for all years analyzed. In other words, for ratemaking purposes, using a three-year historical average rate base balance as the proxy for a test period balance results in a much more severe underestimation of actual test period balances. This historical averaging methodology severely and unnecessarily enhances regulatory lag in the context of ratemaking.

Q. Are there other reasons why using a three-year historical average methodology is inappropriate?

A. Yes. As discussed in earlier sections of my testimony on the establishment of EPIS rate base, the company's proposed rate base methodology in this case aligns all plant

and non-plant rate base components on a simple 13 MA methodology. Isolating a single item, non-fuel M&S, to be calculated as a three-year historical average creates an unnecessary inconsistency in the Test Year rate base.

G. <u>Tab 9 – Embedded Cost Differential</u>

Q. Please describe the information contained behind Tab 9.

A. Tab 9 demonstrates the derivation of the 2020 Protocol ECD amount included in the current rate case.

Q. Please describe the ECD adjustment under 2020 Protocol.

A. Under 2020 Protocol approved originally in Order No. 20-024 in docket UM 1050, the Fixed ECD, as used in the 2017 Protocol, continued for Idaho at $836 thousand through the end of 2023. The Dynamic ECD, as used in the 2010 Protocol, was to continue for Oregon through the end of 2023, capped at $11 million, per the same order in docket UM 1050. No ECD adjustment exists for Utah or California. In Wyoming, the ECD terminated as of December 31, 2020. On June 30, 2023, Order No. 23-229 was issued under docket UM 1050, extending the use of the 2020 Protocol through 2025. Since the company is continuing to use 2020 Protocol for cost allocations in this GRC, the Dynamic ECD continues to be calculated in accordance with the latest order from docket UM 1050.

Q. What is the Dynamic ECD?

A. The Dynamic ECD measures the embedded cost differentials between the production costs of pre-2005 resources, as defined in the 2010 Protocol, and the production cost of west hydro-electric resources and certain Mid-Columbia Contracts. The first part is computed by taking PacifiCorp's production costs related to pre-2005 resources,

expressed in dollars per MWh, compared to production costs of west-side hydro-electric resources expressed in dollars per MWh with the difference multiplied by the hydro-electric resources' MWhs of production. The second part is computed by taking the differential between the pre-2005 resources' dollars per MWh compared to Mid-Columbia Contracts' costs on a dollars per MWh multiplied by the Mid-Columbia Contracts' MWhs.

Q. How much is the ECD amount in this GRC?

A. Since the dynamically calculated ECD amount using Test Period inputs are higher than the $11 million cap stipulated in the 2020 Protocol, the company has reflected the maximum ECD credit of $11 million in this case.

H. <u>Tab 10 – Allocation Factors</u>

Q. Please describe the information contained behind Tab 10 Allocation Factors.

A. Tab 10 Allocation Factors summarizes the derivation of inter-jurisdictional allocation factors using the 2020 Protocol.

I. <u>Tabs B1 to B20</u>

Q. Please describe the information contained behind Tabs B1 to B20.

A. Tabs B1 through B20 contain the historical results for the Base Period and are organized by major FERC function. The data contained in this section of the Report matches the unadjusted data found under Tab 2 – Results of Operations.

VI. WASHINGTON SERVICE AREA TRANSFER

Q. Please provide an overview of the Washington Service Area Transfer.

A. On February 17, 2026, the company announced that it had entered into an agreement with Portland General Electric (PGE) to sell its wind, natural gas generation and

distribution assets and infrastructure in the state of Washington. Applications seeking approval of this transaction were filed in March and April 2026, and the company currently expects the transaction to be approved and close by April 2027.

Q. Does the Washington Service Area Transfer impact the Oregon-allocated revenue requirement in the 2027 Test Period?

A. Yes. Due to the transfer of Washington's service area and related assets, the company must update the underlying data previously used to calculate the Oregon-allocated revenue requirement. For example, because the company will no longer serve customers in Washington, the dynamic allocation factors established under the 2020 Protocol must be revised to remove Washington inputs from the model. As a result, allocations for Oregon will be recalculated based on a five-state system rather than a six-state system. In addition, other revenue-requirement components, including the removal of the sold assets, must be updated and will correspondingly affect the Oregon-allocated revenue requirement.

Q. How are jurisdictional allocation factors revised to reflect the Service Area Transfer?

A. With the transfer of the Washington service area, the company will no longer be serving customers in Washington state. Accordingly, Washington percentages were set to zero, and the remaining percentages were proportionately recalculated for the five other jurisdictions. This approach preserves the dynamic nature of the allocation factors established under the 2020 Protocol and reflects how those factors naturally shift when underlying inputs—such as energy usage—changes for one or more states.

Q. What is the incremental revenue requirement impact of non-NPC changes resulting from the Service Area Transfer?

A. The estimated incremental annual revenue requirement impact of non-NPC updates due to the Service Area Transfer is an increase of approximately $17.3 million. This non-NPC impact is a gross calculation, before application of any rate credits Oregon customers will be receiving for the goodwill value of the business from the Service Area Transfer. The company's proposal is for a second-step price change to take effect when the Service Area Transfer is approved and the transaction closes. At the same time, the company will also begin to pass back to customers associated rate credits from the transaction through Schedule 96, the Oregon property sales balancing account. The impact of the Service Area Transfer on NPC is included in the 2027 TAM.

Q. How was this incremental non-NPC revenue requirement calculated in this GRC?

A. This non-NPC revenue requirement impact was quantified using the same overall methodology and models used to calculate the initial revenue requirement change under the six-state system. Using consistent models and calculation methodologies allows parties to more readily review, verify, and have confidence in reliability of the resulting impact. For this analysis, however, the company began with the fully normalized results from the initial revenue requirement model, including the requested price change. From that baseline, the company applied a series of discrete adjustments to reflect all known and measurable impacts of the Service Area Transfer.

Q. Please describe how the adjustments are developed.

A. The company first reviewed the pre-transaction revenue requirement models and workpapers presented in Exhibit PAC/802 to identify normalizing adjustments expected to change following approval of the Service Area Transfer. The expected change to each adjustment was then quantified, and the resulting incremental impact was layered onto the pre-transaction revenue requirement to produce a revised price change amount—one that reflects the removal of Washington wind, natural gas generation, and distribution assets and infrastructure from PacifiCorp's system. The difference between this revised price change and the originally filed base-rate price change represents the total price change requested in this docket. I describe each of these adjustments in greater detail below.

Q. Can you please describe each adjustment in more detail?

A. Yes. I have provided a separate description of each adjustment in the following section. In addition, I have also provided Exhibit PAC/803 and workpapers supporting each adjustment included in this calculation.

Loads Update (Adjustment WA_1) – This adjustment removes all Washington-related energy and demand from the calculation of the System Energy and System Capacity dynamic load-based allocation factors. Eliminating this load from the System Energy and System Capacity factors also flows through to the System Generation allocation factor, as well as several other load-dependent allocation factor calculations.

Other Allocation Factors Update (Adjustment WA_2) – The company removed in this adjustment the inputs associated with providing service in Washinton from the

calculation of all non-load-based allocation factors, including the Customer Number allocation factor, as well as the situs balances included in the Tax Depreciation allocation factor.

Current Tax Rate Update (Adjustment WA_3) – The company normalizes both federal and state income taxes in the calculation of the Test Period revenue requirement. The normalized state tax rate was 4.54 percent under current, six-state service territory assumptions, but is projected to increase to 5.0 percent as a result of the Service Area Transfer due to the removal of Washington's zero percent state income tax rate in the calculation of the blended income tax rates used in the normalization of current income tax expenses for ratemaking purposes. This increase to the state tax rate impacts the overall calculation of the blended federal and state income tax rate. Accordingly, this adjustment revises the applicable current tax rate impacts in the company's jurisdictional allocation model.

Situs Washington O&M Removal (Adjustment WA_4) – This adjustment removes all Washington situs expense and revenues that are no longer incurred or received as part of the Service Area Transfer. This is reflected as an inverse to the normalized results from the initial revenue requirement calculated assuming the company continues to provide service under a six-state system.

Situs Rate Base Removal (Adjustment WA_5) – Similar to the previous adjustment, this adjustment removes all Washington situs rate base balances from the results.

Generation Resource Removal for Washington Sale (Adjustment WA_6) – As part of the Service Area Transfer, the company agreed to sell the Chehalis natural gas and Goodnoe Hills and Marengo wind generation facilities to PGE. This adjustment

removes the revenue requirement associated with these generation facilities from the results. The tax impacts associated with these assets are removed in PowerTax Adjustment, Adjustment WA_11, and Pro Forma Tax Adjustment, Adjustment WA_12, respectively under Exhibit PAC/803.

Removal of Other Balances for Washington Sales (Adjustment WA_7) – The Service Area Transfer included transfer of certain transmission and distribution assets to PGE. This adjustment removes the revenue requirement associated with these assets from results to the extent they have not yet been removed in the three previous adjustments in this exhibit. Like tax impacts associated with Adjustment WA_6 described above, the tax impacts associated with these other balances are also removed in Adjustment WA_11 and Adjustment WA_12 respectively.

Washington Wheeling Revenues (Adjustment WA_8) – The company anticipates receiving additional transmission wheeling revenues as PGE uses PacifiCorp-owned transmission facilities to serve customers in the newly transferred Washington service area. This adjustment reflects the inclusion of those incremental wheeling revenues into Test Period results.

Chehalis Overhaul Expense Removal (Adjustment WA_9) – To establish a normalized Test Period level of generation overhaul expense in the initial revenue requirement, the company applies a four-year average methodology. Although the base period Chehalis overhaul expense is removed in Adjustment WA_6 – Generation Resource Removal for Washington Sale, the normalization portion of that expense remains in the Test Period revenue requirement calculation. This adjustment removes

the Chehalis generation overhaul expenses from the normalizing adjustment in the results.

Remove Washington Property Tax Expense (Adjustment WA_10) – This adjustment updates the total-company estimated property taxes to reflect the revised total-company property taxes after consideration of the impacts caused by the Service Area Transfer.

PowerTax Adjustment (Adjustment WA_11) – This adjustment captures the deferred tax impacts associated with the assets that were removed in prior adjustments and impacted by the Service Area Transfer.

Pro Forma Tax Adjustment (Adjustment WA_12) – This adjustment removes non-situs balances related to the assets being sold, as well as the income tax rate change impacts on deferred income tax expense, accumulated deferred income taxes and regulatory liabilities.

Prepaid Overhauls Removal (Adjustment WA_13) – The company reflects a forecasted balance for prepaid overhaul expenses in the Test Period through the Miscellaneous Rate Base Adjustment (8.15) in Exhibit PAC/802. Although the unadjusted Chehalis prepaid overhaul balance is removed in Adjustment WA_6 – Generation Resource Removal for Washington Sale, the normalized adjustment of that balance remains in the Test Period revenue requirement calculation. This adjustment removes the remaining normalization adjustment of the Chehalis prepaid balance from the results.

Washington Unamortized Pension Loss (Adjustment WA_14) – Test Period expenses presented in Exhibit PAC/802 reflects a forecasted level of pension and

post-retirement amortizations which includes Washington's share of unamortized pension gains and losses. This adjustment removes Washington's share of the amortization from the Test Period expenses.

Washington Accelerated Depreciation and Decommissioning (Adjustment WA_15) – Included in the company's Washington base retail rates was an amount associated with accelerated depreciation and decommissioning costs for the Jim Bridger and Colstrip steam generation plants. Because these assets are being retained and will continue to be allocated to the remaining PacifiCorp retail jurisdictions, Oregon customers will receive an incremental credit for the balances Washington customers have paid related to these facilities. Accordingly, this adjustment reflects an additional reduction to rate base to account for the accelerated depreciation and decommissioning balances previously recovered from Washington customers.

Q. How is the company proposing to implement this incremental rate change?

A. The company proposes to begin collecting this annual incremental revenue requirement through an adjustment to base rates upon approval and closing of the Service Area Transfer or with the effective date of this GRC, whichever is later. While the company is currently anticipating that the transaction will close by April 1, 2027, there remains uncertainty around when approval from all states would be achieved. This proposal protects customers and ensures that the incremental revenue requirement is only collected in rates after the Service Area Transfer is approved and has closed.

Q. What considerations are made for the estimated April 1, 2027, closing date for the Service Area Transfer?

A. To accurately and comprehensively model the impact of the Service Area Transfer, the company created an alternate calculation of Test Period results of operations that assumes the effects of the transaction were in place for the entirety of the Test Period. This resulting calculation allows the incremental revenue requirement impact to remain flexible and be reflected as a second-step rate change only after the transaction is approved and closed. Should the approval and closing happen in advance of the conclusion of this GRC, then annual rates put into effect will include the full incremental annual revenue requirement effect of the Service Area Transfer upon the rate effective date. However, should the approval be delayed, the incremental impact can then be effected as a second-step rate change after the initially proposed rate effective date of July 15, 2027, to align with the final closing timing of the Service Area Transfer.

Q. What about the timing of any rate credit to be passed back to Oregon customers upon the closing of the transaction?

A. The Company will effectuate a rate update to the Schedule 96, Oregon's property sales balancing account, to pass back to Oregon customers any rate credits resulting from the Service Area Transfer at the same time when the incremental annual revenue requirement is put into base rates, after the closing of the Service Area Transfer.

Q. Is the amount of rate credit to be passed back to Oregon customers known at this time?

A. According to the transaction filings made by the company earlier this year, the total

rate credit to be passed back to Oregon customers is currently projected to be approximately $40.0 million. Based on this projection, I have included an amortization schedule presenting a three-year amortization projection of this amount under Exhibit PAC/809, resulting in an annual credit of $14.3 million. The projected amortization assumes accrual of interest at the modified blended treasury rate. However, this amount is subject to change in accordance with the outcome of docket UP 441, the company's Application for an Order Authorizing the Sale of Washington-Based Assets.

VII. INTERIM RATES PROPOSAL

Q. What is an interim rates proposal?

A. As discussed in the direct testimony of company witnesses Flynn and Link, the company is including in this GRC a request to implement interim rates. An interim rate proposal is a request by a utility to change rates before the Commission issues a final order in a GRC or other contested rate proceeding. The direct testimony of company witness Link presents and explains the company's interim rates proposal in greater detail. My testimony will address how the company's interim rate request was calculated.

Q. What is the company's requested interim rate change?

A. While the company is providing information to support an interim rate increase of $98.5 million, PacifiCorp is seeking to implement an interim rate increase of $55.1 million, effective 30 days from filing of this GRC. As discussed in the testimony of company witnesses Link and Judith M. Ridenour, this request results in bills being at

the same level as prior to May 1, 2026, for the average residential customer when also considering the May 1, 2026 PCAM decrease.

Q. How does the interim rate request differ from the company's final rate request in this case?

A. Interim rates are temporary, subject to refund, and reflect a limited subset of costs rather than the full Test Period revenue requirement.

Q. What costs are reflected in the interim revenue requirement calculation?

A. The company's proposed interim rate change is based on a subset of non-NPC costs that are known, measurable, and currently incurred. As presented in Exhibit PAC/811, the total revenue requirement of costs meeting these criteria is approximately $98.5 million. However, as discussed in the direct testimony of company witness Link, the company is also voluntarily limiting its request for an interim rate change to $55.1 million. Please refer to Exhibit PAC/811 and associated workpapers for details supporting the company's interim rate request in this GRC.

Q. What costs are expressly considered in the calculation of the interim rate calculation?

A. The company's interim rate request considers the following expenses:

- Increase to the company's property self-insurance reserve accrual, reflecting the shortening of the historical averaging period from ten years as approved in the company's most recently concluded GRC to three years as discussed above;
- Increase in excess liability insurance premiums for policies that took effect in February and March of 2026;

- Recovery of the Willamette River Crossing distribution project that will be placed in-service in the first half of 2026;
- Increase in the company's net plant in-service rate base and associated depreciation expense through end of year 2025 incremental to balances approved in the company's most recently concluded GRC, docket UE 433; and
- Annualized increase of the company's labor expenses through 2025 relative to corresponding labor expenses reflected in rates.

Q. Why did the company only include these cost categories in its interim request?

A. The primary principle guiding the company's decision to include these discrete cost categories is because these costs are incremental, known, and quantifiable costs that the company will be incurring in 2026, during the pendency of the current GRC. By including costs meeting these criteria, the company aims to present a conservative estimate of presently incurring costs that are not being recovered in currently approved Oregon rates, and to support administrative efficiency in the Commission's review of the proposed interim rate change, while avoiding the need to prejudge contested issues or forecast costs in the GRC.

Q. What methodology did the company use to calculate the interim revenue requirement?

A. To quantify the total interim rate increase request, the company calculated the level of costs that are being incurred to serve Oregon customers in 2026 for each identified cost category as described above. This quantified amount of expense is then compared to the corresponding level of the same cost approved in the company's most recently concluded GRC, docket UE 433. The differential between quantified

amounts known to be incurring through 2026, and approved levels from docket UE 433, represents the adjustment to rates that the company is requesting as its interim rate change. A dedicated workpaper calculating the adjustment for each cost category is provided in support of Exhibit PAC/811.

Q. When would the interim rate change take effect, if approved?

A. The company is seeking approval to implement this interim rate change within 30 days of the submission of this application.

Q. What ROE and capital structure assumptions were used?

A. The company has calculated the revenue requirement of identified costs in its interim rate request assuming the return on equity and capital structure assumptions that were approved in docket UE 433. This rate of return assumption helps eliminate the need for the Commission to prejudge the appropriateness of the company's requested rate of return in this case prior to authorizing interim rates in accordance with the company's request.

Q. How does the requested interim increase compare to the total revenue increase requested in this GRC?

A. The company's requested interim rate change of $55.1 million is approximately 34 percent of the company's total non-NPC $161.7 million price change requested in this case. As noted earlier in my testimony, this increase amount was intentionally established to offset the reduction in customer rates due to the cessation in recovery of 2022 deferred NPC through the PCAM on May 1, 2026.

Q. Are the proposed interim rates subject to refund?

A. Yes.

Q. How will interim rates interact with permanent rates once a final order is issued?

A. Once a final Commission order is issued for the totality of this GRC, interim rates will stop, and the final approved level of base rates in accordance with the final GRC order will take effect upon the approved rate effective date. Witness Ridenour discusses how a rate credit would be implemented should the Commission order a refund.

Q. Does approval of interim rates presuppose approval of any specific issue in this GRC?

A. No.

VIII. AMORTIZATIONS AND OTHER UPDATES

Q. Is the company proposing any changes to other existing rate schedules beyond the updates to base rates described above?

A. Yes, in this GRC, the company is also seeking to address recovery of deferred costs under four deferral balances. These include deferrals for costs relating to:

- Rock Creek I Wind Project[32]
- Rock Creek II Wind Project[33]
- RAC Residential Rate Change[34]
- Incremental Liability Insurance Premium[35]

[32] *In the Matter of PacifiCorp d/b/a Pacific Power, Application for Deferral of Costs Relating to Rock Creek I and Gateway South*, Docket No. UM 2402, Application (Aug. 15, 2025).
[33] *In the Matter of PacifiCorp d/b/a Pacific Power, Application of Deferred Accounting for Costs Associated with Completion of Rock Creek II Turbines*, Docket No. UM 2430, Application (Jan. 29, 2026).
[34] *In the Matter of PacifiCorp d/b/a Pacific Power, Application for Approval of Deferred Accounting for Costs Relating to the Renewable Adjustment Clause*, Docket No. UM 2426, Application (Dec. 31, 2025).
[35] *In the Matter of PacifiCorp d/b/a Pacific Power, Application for Authorization of Deferred Accounting Related to Insurance Costs*, Docket No. UM 2433, Application (Feb. 13, 2026).

Q. Please provide a brief explanation of the costs captured in each of the deferral balances identified above.

A. The Rock Creek I Wind Project deferral captures costs associated with the Rock Creek I wind facility, specifically the portion of costs placed in-service after December 31, 2024. In the company's 2025 GRC, the portion of Rock Creek I wind facility that was attested to be in-service by the time the company's compliance filing was prepared is already reflected rates effective January 1, 2025. In April 2025, the company filed a RAC for Rock Creek I and II facilities, which ultimately was approved for rate change effective January 1, 2026. Between the time when the remainder of the Rock Creek I facility was fully placed in-service, and January 1, 2026, the costs placed in-service that are used and useful to customers were not being recovered through Oregon rates. However, customers were benefiting from this resource through the no fuel cost generation and PTCs reflected in the TAM and PCAM. Accordingly, this deferral captures the revenue requirement of the capital project, and associated costs, of Rock Creek I not in rates during this interim period.

The Rock Creek II Wind Project deferral captures costs associated with the Rock Creek II wind facility that were not yet placed in-service by the time the company's compliance filing for the RAC was prepared. Rates effective January 1, 2026, in the RAC reflected in-service costs for 62 of 66 turbines of the Rock Creek II wind facility. The remaining turbines have been placed in-service since, but the costs associated with these turbines are not currently being recovered in rates. Customers are benefiting from this resource through the no fuel cost generation and PTCs reflected in the TAM and PCAM. Accordingly, this deferral tracks those costs not yet

in rates, until such time the entirety of the capital investments in Rock Creek II can be included in rate base with rates taking effect January 1, 2027, with this GRC.

The RAC Residential Rate Change deferral tracks the costs associated with the delay in the residential rate increase from the RAC because of the Fairness & Affordability in Residential (FAIR) Energy Act. In January 2026, the RAC rate change was approved, but due to the limitations imposed by the FAIR Act, the rate change for residential customers could not take effect until April 1, 2026. This deferral calculates the missed residential revenues between January 2026 through March 2026 based on actual usage recorded for Oregon residential customers, multiplied by the approved dollar per kilowatt hour rate as approved in the RAC.

Finally, the Incremental Liability Insurance Premium deferral tracks the differential between actual liability insurance premiums and liability insurance premiums levels built into rates. Consistent with the 2025 GRC order, the deferral amounts represent only 90 percent of the differential between amounts in rates and actual renewal amounts.

All deferrals described above accrue interest using the weighted average cost of capital during the deferral period, and assumes the interest rate decreases to the Modified Blended Treasury Rate for the amortization period. All four deferral and amortization schedules were prepared assuming interim rates effective June 4, 2026, with amortization beginning July 15, 2027. PacifiCorp is proposing a three-year amortization period for the RAC – Residential Rate Change and a one-year amortization period for the other three deferral balances.

Q. Can you provide a summary of the total annual amortization amounts requested?

A. Yes. Please refer to Table 4 below for a summary of annual amortization amounts requested in this filing. Detailed amortization schedules and support for the calculation of amortization amounts can be found in Exhibit PAC/809.

Table 4 – Summary of Proposed Deferral Amortizations

Docket	Deferral	June 30, 2027 Balance	Proposed Amortization Period	Annual Amortization
UM 2402	Costs Relating to Rock Creek I	$2,484,568	1 Year	$2,551,929
UM 2430	Costs Associated with Completion of Rock Creek II Turbines	$1,507,301	1 Year	$1,604,044
UM 2426	Renewable Adjustment Clause – Residential Rate Change	$5,066,033	3 Year	$1,811,370
UM 2433	Costs Associated with Increased Insurance Premiums	$1,495,520	1 Year	$1,584,654

Please note that the estimated deferral balance and projected annual amortization of costs associated with increased insurance premiums provided in Table 4 assume the company's interim rates request is approved and the company can begin collecting some level of revenues to pay for a portion of the incremental costs. Should the company's interim rate request be denied, resulting in no incremental revenues to pay for the incremental costs until the rate effective date of this GRC, the total deferred cost with interest would grow to approximately $2.5 million by the time the balance can begin to amortize. The company is seeking to amortize the projected balance through its deferred accounting rate adjustment, as described in the direct testimony of company witness Ridenour.

Q. Does the company have any other proposed updates to existing rate schedules?

A. Yes. As with PacifiCorp's most recently concluded rate case, the 2025 GRC, the company is including a true-up calculation to Schedule 190, for recovery of costs under the WMP AAC. As agreed upon in the company's 2023 WMP AAC filing settlement in Advice No. 23-015 (docket ADV 1529), and then implemented in docket UE 433, the company has presented a true-up of the WMP AAC rate in Schedule 190 to reflect inclusion of indirect loadings, or overhead, amounts associated with WMP assets, placed in-service since its most recently concluded GRC, that have otherwise already been approved to be recovered under the AAC. This true-up for indirect loadings to be included in the WMP AAC rate is only made when the company files a GRC to update base rates. In WMP AAC filings in between GRC years, the company continues to agree to exclude indirect loadings from the incremental wildfire mitigation capital project costs from WMP AAC filings 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. Additionally, the company is incorporating a true-up in the WMP AAC rate calculation to capital structure and capital costs assumptions consistent with its requested return in this filing.

Q. Is the anticipated impact to truing up costs in the WMP ACC known at this time?

A. Not exactly. According to established schedules, WMP AAC filings are expected to be made around July 1 each year to incorporate additional incremental costs on an

annual basis. Typically, these annual filings would reflect incremental capital placed in-service through the first quarter of the filing year, and new rates for the WMP AAC are expected to be effective by the end of October in the same year. Based on these assumptions, the true-up to the WMP AAC rate that would need to happen on July 15, 2027, will depend on the approved rate for Schedule 190 coming out of the 2026 WMP AAC filing that is approved late 2026, but before the rate effective date sought in this GRC.

Q. Can the company provide an illustrative demonstration of how the July 15, 2027, WMP AAC rate update would be calculated based on the currently approved WMP AAC rate in Schedule 190?

A. Yes. Please refer to Exhibit PAC/810, which is formatted in a way that intentionally mimics the workpaper that was submitted to the Commission in support of the Advice No. 25-012 (docket ADV 1745) resolution of PacifiCorp's 2025 WMP AAC filing. In the workpaper supporting Exhibit PAC/810, tabs that are new or contain information that has changed or been modified from the workpaper previously submitted in docket ADV 1745 have been identified and color-coded in green to facilitate comparison between calculations presented in Exhibit PAC/810, against those previously presented in the docket ADV 1745 final workpapers. The true-up of the WMP AAC rate would entail a recalculation of the effective rate under the WMP AAC just before final approved rates take effect for this case. Exhibit PAC/810 assumes no change to the WMP AAC rate between the time of this filing and that point in time. Based on that, the WMP AAC rate is recalculated to capture overhead costs that were previously excluded in the company's annual WMP AAC filings, in

adherence to the settlement agreement from docket ADV 1529, and to reflect the proposed rate of return in this GRC. No incremental costs are otherwise reflected in this recalculation to ensure that all projects being recovered through the updated WMP AAC remain the same as those that have been audited and reviewed for prudence by the Commission in the company's most recently concluded annual WMP AAC update filing. Under these assumptions, the WMP AAC rate would go from the currently approved $18.8 million to a total of $20.2 million, resulting in an approximately $1.4 million increase.

Q. How would this true-up calculation change if a new WMP AC rate was approved before the rate effective date of this GRC?

A. If a new WMP AAC rate is established before the rate effective date of this case, as is expected based on the assumed timeline for the company's 2026 WMP AAC filing, then the true-up calculation would need to be calculated relative to the approved 2026 WMP AAC rate.

IX. CONCLUSION

Q. Please summarize your testimony.

A. I recommend that the Commission approve the requested $161.7 million increase and non-NPC revenue requirement of $1,393.6 million. I further recommend the Commission approve the company's request to begin amortization and recovery of costs recorded under the four deferral mechanisms, as well as the modification to Schedule 190 for the true-up of overhead costs previously excluded and the update of assumed rate of return described in my testimony above.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 470
Exhibit PAC/801
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Revenue Requirement Summary

May 2026

PacifiCorp **Page 1.0**

OREGON

Normalized Results of Operations - 2020 PROTOCOL

Twelve Months Ending December 31, 2027

	(1)	(2) (3) - (1)	(3) Ref. Page 1.2	(4) **TAM**	(5) **GRC**	(6) (3) + (4) + (5)
	NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Price Change	Requested Non-NPC Related Price Change	Total Normalized Results with Price Change
1 Operating Revenues:						
2 General Business Revenues	561,429,046	1,231,876,445	1,793,305,491	(55,709,435)	161,748,527	1,899,344,584
3 Interdepartmental		-	-			-
4 Special Sales	54,006,161	-	54,006,161			54,006,161
5 Other Operating Revenues		74,085,068	74,085,068			74,085,068
6 Total Operating Revenues	615,435,207	1,305,961,513	1,921,396,720	(55,709,435)	161,748,527	2,027,435,813
7						
8 Operating Expenses:						
9 Steam Production	174,552,460	89,795,716	264,348,177			264,348,177
10 Nuclear Production		-	-			-
11 Hydro Production		13,378,082	13,378,082			13,378,082
12 Solar Production		232,196	232,196			232,196
13 Wind Production		10,283,870	10,283,870			10,283,870
14 Other Renewable Production	1,565,734	432,169	1,997,903			1,997,903
15 Other Power Supply	424,446,542	24,945,085	449,391,626			449,391,626
16 Transmission	66,612,911	24,694,200	91,307,111			91,307,111
17 Distribution		125,776,662	125,776,662			125,776,662
18 Customer Accounting		32,131,875	32,131,875		660,781	32,792,656
19 Customer Service & Info		5,324,067	5,324,067			5,324,067
20 Sales		-	-			-
21 Administrative & General		140,886,076	140,886,076			140,886,076
22						
23 Total O&M Expenses	667,177,647	467,879,998	1,135,057,645	-	660,781	1,135,718,426
24						
25 Depreciation		337,794,580	337,794,580			337,794,580
26 Amortization		(295,207)	(295,207)			(295,207)
27 Taxes Other Than Income		112,881,934	112,881,934		2,929,323	115,811,257
28 Income Taxes - Federal	(91,405,712)	30,777,021	(60,628,691)	(11,167,848)	31,705,386	(40,091,152)
29 Income Taxes - State	(2,349,107)	7,490,696	5,141,589	(2,529,208)	7,180,392	9,792,773
30 Income Taxes - Def Net		9,027,360	9,027,360			9,027,360
31 Investment Tax Credit Adj.		-	-			-
32 Misc Revenue & Expense		(104,716)	(104,716)			(104,716)
33						
34 Total Operating Expenses:	573,422,828	965,451,667	1,538,874,495	(13,697,056)	42,475,883	1,567,653,322
35						
36 Operating Rev For Return:	42,012,379	340,509,847	382,522,225	(42,012,379)	119,272,644	459,782,491
37						
38 Rate Base:						
39 Electric Plant In Service		11,726,376,909	11,726,376,909			11,726,376,909
40 Plant Held for Future Use		-	-			-
41 Misc Deferred Debits		93,002,614	93,002,614			93,002,614
42 Elec Plant Acq Adj		684,215	684,215			684,215
43 Pension		-	-			-
44 Prepayments		51,058,541	51,058,541			51,058,541
45 Fuel Stock		89,834,980	89,834,980			89,834,980
46 Material & Supplies		239,908,978	239,908,978			239,908,978
47 Working Capital		62,523,353	62,523,353			62,523,353
48 Weatherization Loans		-	-			-
49 Misc Rate Base		(14,356,267)	(14,356,267)			(14,356,267)
50						
51 Total Electric Plant:	-	12,249,033,325	12,249,033,325			12,249,033,325
52						
53 Rate Base Deductions:						
54 Accum Prov For Deprec		(4,896,570,165)	(4,896,570,165)			(4,896,570,165)
55 Accum Prov For Amort		(45,207,495)	(45,207,495)			(45,207,495)
56 Accum Def Income Tax		(778,022,691)	(778,022,691)			(778,022,691)
57 Unamortized ITC		(26,013)	(26,013)			(26,013)
58 Customer Adv For Const		(88,409,248)	(88,409,248)			(88,409,248)
59 Customer Service Deposits		-	-			-
60 Misc Rate Base Deductions		(354,993,731)	(354,993,731)			(354,993,731)
61						
62 Total Rate Base Deductions	-	(6,163,229,344)	(6,163,229,344)			(6,163,229,344)
63						
64 Total Rate Base:	-	6,085,803,981	6,085,803,981			6,085,803,981
65						
66 Return on Rate Base			6.285%			7.555%
67						
68 Return on Equity			7.161%			9.700%

Ref. Page 1.2

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2027

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	1,231,876,445	161,748,527	1,393,624,972
3	Interdepartmental	-		-
4	Special Sales	-		-
5	Other Operating Revenues	74,085,068		74,085,068
6	Total Operating Revenues	1,305,961,513	161,748,527	1,467,710,040
7				
8	Operating Expenses:			
9	Steam Production	89,795,716		89,795,716
10	Nuclear Production	-		-
11	Hydro Production	13,378,082		13,378,082
12	Solar Production	232,196		232,196
13	Wind Production	10,283,870		10,283,870
14	Other Renewable Production	432,169		432,169
15	Other Power Supply	24,945,085		24,945,085
16	Transmission	24,694,200		24,694,200
17	Distribution	125,776,662		125,776,662
18	Customer Accounting	32,131,875	660,781	32,792,656
19	Customer Service & Info	5,324,067		5,324,067
20	Sales	-		-
21	Administrative & General	140,886,076		140,886,076
22				
23	Total O&M Expenses	467,879,998	660,781	468,540,779
24				
25	Depreciation	337,794,580		337,794,580
26	Amortization	(295,207)		(295,207)
27	Taxes Other Than Income	112,881,934	2,929,323	115,811,257
28	Income Taxes - Federal	30,777,021	31,705,386	62,482,408
29	Income Taxes - State	7,490,696	7,180,392	14,671,089
30	Income Taxes - Def Net	9,027,360		9,027,360
31	Investment Tax Credit Adj.	-		-
32	Misc Revenue & Expense	(104,716)		(104,716)
33				
34	Total Operating Expenses:	965,451,667	42,475,883	1,007,927,550
35				
36	Operating Rev For Return:	340,509,847	119,272,644	459,782,491
37				
38	Rate Base:			
39	Electric Plant In Service	11,726,376,909		11,726,376,909
40	Plant Held for Future Use	-		-
41	Misc Deferred Debits	93,002,614		93,002,614
42	Elec Plant Acq Adj	684,215		684,215
43	Pension	-		-
44	Prepayments	51,058,541		51,058,541
45	Fuel Stock	89,834,980		89,834,980
46	Material & Supplies	239,908,978		239,908,978
47	Working Capital	62,523,353		62,523,353
48	Weatherization Loans	-		-
49	Misc Rate Base	(14,356,267)		(14,356,267)
50				
51	Total Electric Plant:	12,249,033,325		12,249,033,325
52				
53	Rate Base Deductions:			
54	Accum Prov For Deprec	(4,896,570,165)		(4,896,570,165)
55	Accum Prov For Amort	(45,207,495)		(45,207,495)
56	Accum Def Income Tax	(778,022,691)		(778,022,691)
57	Unamortized ITC	(26,013)		(26,013)
58	Customer Adv For Const	(88,409,248)		(88,409,248)
59	Customer Service Deposits	-		-
60	Misc Rate Base Deductions	(354,993,731)		(354,993,731)
61				
62	Total Rate Base Deductions	(6,163,229,344)		(6,163,229,344)
63				
64	Total Rate Base:	6,085,803,981		6,085,803,981
65				
66	Return on Rate Base	5.595%		7.555%
67				
68	Return on Equity	5.780%		9.700%
69				
70	TAX CALCULATION:			
71	Operating Revenue	387,804,924	158,158,423	545,963,347
72	Other Deductions			
73	Interest (AFUDC)	(2,826,222)	-	(2,826,222)
74	Interest	164,620,998	-	164,620,998
75	Schedule "M" Additions	329,762,524	-	329,762,524
76	Schedule "M" Deductions	401,633,646	-	401,633,646
77	Income Before Tax	154,139,027	158,158,423	312,297,450
78				
79	State Income Taxes	7,490,696	7,180,392	14,671,089
80	Taxable Income	146,648,331	150,978,031	297,626,361
81				
82	Federal Income Taxes + Other	30,777,021	31,705,386	62,482,408

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2027

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	561,429,046	(55,709,435)	505,719,611
3	Interdepartmental	-		-
4	Special Sales	54,006,161		54,006,161
5	Other Operating Revenues	-		-
6	Total Operating Revenues	615,435,207	(55,709,435)	559,725,772
7				
8	Operating Expenses:			
9	Steam Production	174,552,460		174,552,460
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Solar Production	-		-
13	Wind Production	-		-
14	Other Renewable Production	1,565,734		1,565,734
15	Other Power Supply	424,446,542		424,446,542
16	Transmission	66,612,911		66,612,911
17	Distribution	-		-
18	Customer Accounting	-	-	-
19	Customer Service & Info	-		-
20	Sales	-		-
21	Administrative & General	-		-
22				
23	Total O&M Expenses	667,177,647	-	667,177,647
24				
25	Depreciation	-		-
26	Amortization	-		-
27	Taxes Other Than Income	-	-	-
28	Income Taxes - Federal	(91,405,712)	(11,167,848)	(102,573,559)
29	Income Taxes - State	(2,349,107)	(2,529,208)	(4,878,315)
30	Income Taxes - Def Net	-		-
31	Investment Tax Credit Adj.	-		-
32	Misc Revenue & Expense	-		-
33				
34	Total Operating Expenses:	573,422,828	(13,697,056)	559,725,772
35				
36	Operating Rev For Return:	42,012,379	(42,012,379)	-
37				
38	Rate Base:			
39	Electric Plant In Service	-		-
40	Plant Held for Future Use	-		-
41	Misc Deferred Debits	-		-
42	Elec Plant Acq Adj	-		-
43	Pension	-		-
44	Prepayments	-		-
45	Fuel Stock	-		-
46	Material & Supplies	-		-
47	Working Capital	-		-
48	Weatherization Loans	-		-
49	Misc Rate Base	-		-
50				
51	Total Electric Plant:	-		-
52				
53	Rate Base Deductions:			
54	Accum Prov For Deprec	-		-
55	Accum Prov For Amort	-		-
56	Accum Def Income Tax	-		-
57	Unamortized ITC	-		-
58	Customer Adv For Const	-		-
59	Customer Service Deposits	-		-
60	Misc Rate Base Deductions	-		-
61				
62	Total Rate Base Deductions	-		-
63				
64	Total Rate Base:	-		-
65				
66	Return on Rate Base	N/A		N/A
67				
68	Return on Equity	N/A		N/A
69				
70	TAX CALCULATION:			
71	Operating Revenue	(51,742,440)	(55,709,435)	(107,451,875)
72	Other Deductions			
73	Interest (AFUDC)	-	-	-
74	Interest	-	-	-
75	Schedule "M" Additions	-	-	-
76	Schedule "M" Deductions	-	-	-
77	Income Before Tax	(51,742,440)	(55,709,435)	(107,451,875)
78				
79	State Income Taxes	(2,349,107)	(2,529,208)	(4,878,315)
80	Taxable Income	(49,393,333)	(53,180,226)	(102,573,559)
81				
82	Federal Income Taxes + Other	(10,372,600)	(11,167,848)	(21,540,447)

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2027

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,793,305,491	106,039,093	1,899,344,584
3	Interdepartmental	-		
4	Special Sales	54,006,161		
5	Other Operating Revenues	74,085,068		
6	Total Operating Revenues	1,921,396,720		
7				
8	Operating Expenses:			
9	Steam Production	264,348,177		
10	Nuclear Production	-		
11	Hydro Production	13,378,082		
12	Solar Production	232,196		
13	Wind Production	10,283,870		
14	Other Renewable Production	1,997,903		
15	Other Power Supply	449,391,626		
16	Transmission	91,307,111		
17	Distribution	125,776,662		
18	Customer Accounting	32,131,875	660,781	32,792,656
19	Customer Service & Info	5,324,067		
20	Sales	-		
21	Administrative & General	140,886,076		
22				
23	Total O&M Expenses	1,135,057,645		
24				
25	Depreciation	337,794,580		
26	Amortization	(295,207)		
27	Taxes Other Than Income	112,881,934	2,929,323	115,811,257
28	Income Taxes - Federal	(60,628,691)	20,537,539	(40,091,152)
29	Income Taxes - State	5,141,589	4,651,184	9,792,773
30	Income Taxes - Def Net	9,027,360		
31	Investment Tax Credit Adj.	-		
32	Misc Revenue & Expense	(104,716)		
33				
34	Total Operating Expenses:	1,538,874,495	28,778,827	1,567,653,322
35				
36	Operating Rev For Return:	382,522,225	77,260,265	459,782,491
37				
38	Rate Base:			
39	Electric Plant In Service	11,726,376,909		
40	Plant Held for Future Use	-		
41	Misc Deferred Debits	93,002,614		
42	Elec Plant Acq Adj	684,215		
43	Pensions	-		
44	Prepayments	51,058,541		
45	Fuel Stock	89,834,980		
46	Material & Supplies	239,908,978		
47	Working Capital	62,523,353		
48	Weatherization Loans	-		
49	Misc Rate Base	(14,356,267)		
50				
51	Total Electric Plant:	12,249,033,325	-	12,249,033,325
52				
53	Rate Base Deductions:			
54	Accum Prov For Deprec	(4,896,570,165)		
55	Accum Prov For Amort	(45,207,495)		
56	Accum Def Income Tax	(778,022,691)		
57	Unamortized ITC	(26,013)		
58	Customer Adv For Const	(88,409,248)		
59	Customer Service Deposits	-		
60	Misc Rate Base Deductions	(354,993,731)		
61				
62	Total Rate Base Deductions	(6,163,229,344)	-	(6,163,229,344)
63				
64	Total Rate Base:	6,085,803,981	-	6,085,803,981
65				
66	Return on Rate Base	6.285%		7.555%
67				
68	Return on Equity	7.161%		9.700%
69				
70	TAX CALCULATION:			
71	Operating Revenue	336,062,484	102,448,988	438,511,473
72	Other Deductions			
73	Interest (AFUDC)	(2,826,222)	-	(2,826,222)
74	Interest	164,620,998	-	164,620,998
75	Schedule "M" Additions	329,762,524	-	329,762,524
76	Schedule "M" Deductions	401,633,646	-	401,633,646
77	Income Before Tax	102,396,587	102,448,988	204,845,576
78				
79	State Income Taxes	5,141,589	4,651,184	9,792,773
80	Taxable Income	97,254,998	97,797,804	195,052,802
81				
82	Federal Income Taxes + Other	(60,628,691)	20,537,539	(40,091,152)

Ref. Page 2.2

PacifiCorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2027

	Exhibit PAC/802		Exhibit PAC/802			
			Tab 3	Tab 4	Tab 5	Tab 6
	TOTAL COMPANY UNADJUSTED RESULTS JUNE 2025	OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2025	Revenue Adjustments	O&M Adjustments	Net Power Cost Adjustments	Depreciation & Amortization Adjustments
1 Operating Revenues:						
2 General Business Revenues	6,686,582,827	1,817,705,929	(24,444,721)	44,283	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	140,270,178	34,258,193	-	-	19,747,968	-
5 Other Operating Revenues	300,432,890	78,092,441	(4,007,373)	-	-	-
6 Total Operating Revenues	7,127,285,895	1,930,056,563	(28,452,094)	44,283	19,747,968	-
7						
8 Operating Expenses:						
9 Steam Production	1,139,769,280	309,090,420	-	7,201,933	(46,107,869)	(5,341,821)
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	50,837,074	14,110,122	-	(299,697)	-	-
12 Solar Production	208,052	208,052	-	24,144	-	-
13 Wind Production	27,619,506	7,665,953	-	355,570	-	-
14 Other Renewable Production	1,482,364	411,439	-	20,730	1,565,734	-
15 Other Power Supply	2,075,654,989	487,690,216	-	947,362	(39,034,848)	-
16 Transmission	289,030,036	79,976,259	-	(3,378,890)	14,709,743	-
17 Distribution	355,741,131	143,286,453	-	(17,509,790)	-	-
18 Customer Accounting	95,817,305	30,068,565	-	2,063,311	-	-
19 Customer Service & Info	237,560,141	4,961,172	-	362,895	-	-
20 Sales	-	-	-	-	-	-
21 Administrative & General	448,859,752	141,770,244	-	(167,125)	(40,745)	-
22						
23 Total O&M Expenses	4,722,579,629	1,219,238,893	-	(10,379,558)	(68,907,986)	(5,341,821)
24						
25 Depreciation	1,194,509,229	311,069,907	-	-	-	26,463,303
26 Amortization	46,386,797	11,605,919	-	-	-	(11,702,006)
27 Taxes Other Than Income	230,247,482	95,458,958	-	(584,460)	-	-
28 Income Taxes - Federal	(279,264,551)	(80,160,228)	(5,702,527)	21,089,675	17,780,254	2,216,908
29 Income Taxes - State	6,575,518	5,041,783	(1,291,464)	4,776,228	4,026,735	502,068
30 Income Taxes - Def Net	80,393,832	35,250,752	-	(25,408,597)	-	1,773,062
31 Investment Tax Credit Adj.	(363,488)	-	-	-	-	-
32 Misc Revenue & Expense	(5,597,257)	(1,384,747)	-	1,280,031	-	-
33						
34 Total Operating Expenses:	5,995,467,190	1,596,121,237	(6,993,991)	(9,226,682)	(47,100,997)	13,911,514
35						
36 Operating Rev For Return:	1,131,818,705	333,935,327	(21,458,103)	9,270,965	66,848,965	(13,911,514)
37						
38 Rate Base:						
39 Electric Plant In Service	38,550,771,333	10,979,995,227	-	-	-	-
40 Plant Held for Future Use	11,192,650	4,968,037	-	-	-	-
41 Misc Deferred Debits	1,963,844,323	171,300,366	-	-	-	-
42 Elec Plant Acq Adj	11,200,196	705,129	-	-	-	-
43 Pensions	158,341,112	44,191,249	-	-	-	-
44 Prepayments	174,702,384	51,058,541	-	-	-	-
45 Fuel Stock	297,728,656	79,859,122	-	-	-	-
46 Material & Supplies	671,506,101	239,908,978	-	-	-	-
47 Working Capital	211,067,996	72,749,385	(212,206)	452,140	(1,429,098)	(9,082,253)
48 Weatherization Loans	350,500,629	-	-	-	-	-
49 Misc Rate Base	-	-	-	-	-	-
50						
51 Total Electric Plant:	42,400,855,379	11,644,736,034	(212,206)	452,140	(1,429,098)	(9,082,253)
52						
53 Rate Base Deductions:						
54 Accum Prov For Deprec	(13,328,358,351)	(3,913,070,370)	-	-	-	(1,014,760,876)
55 Accum Prov For Amort	(163,684,346)	(46,856,104)	-	-	-	1,648,609
56 Accum Def Income Tax	(2,954,148,265)	(677,336,618)	-	(95,544,651)	-	3,141,294
57 Unamortized ITC	(1,946,575)	(40,621)	-	-	-	-
58 Customer Adv For Const	(333,031,816)	(139,027,223)	-	-	-	-
59 Customer Service Deposits	-	-	-	-	-	-
60 Misc Rate Base Deductions	(2,554,751,473)	(764,989,851)	-	385,972,065	-	(4,597,430)
61						
62 Total Rate Base Deductions	(19,335,920,826)	(5,541,320,788)	-	290,427,413	-	(1,014,568,403)
63						
64 Total Rate Base:	23,064,934,553	6,103,415,246	(212,206)	290,879,554	(1,429,098)	(1,023,650,656)
65						
66 Return on Rate Base		5.471%	-0.351%	-0.088%	1.047%	0.900%
67						
68 Return on Equity		5.533%	-0.703%	-0.176%	2.094%	1.800%
69						
70 TAX CALCULATION:						
71 Operating Revenue		294,067,633	(28,452,094)	9,728,270	88,655,954	(9,419,476)
72 Other Deductions						
73 Interest (AFUDC)		(42,774,659)	-	-	-	-
74 Interest		165,097,382	(5,740)	7,868,292	(38,657)	(27,689,750)
75 Schedule "M" Additions		418,741,622	-	-	-	(7,211,499)
76 Schedule "M" Deductions		664,451,978	-	(103,343,273)	-	-
77 Income Before Tax		(73,965,445)	(28,446,354)	105,203,251	88,694,612	11,058,775
78						
79 State Income Taxes		5,041,783	(1,291,464)	4,776,228	4,026,735	502,068
80 Taxable Income		(79,007,229)	(27,154,890)	100,427,023	84,667,876	10,556,706
81						
82 Federal Income Taxes + Other		(80,160,228)	(5,702,527)	21,089,675	17,780,254	2,216,908
APPROXIMATE PRICE CHANGE		174,550,317	29,446,997	17,419,609	(91,897,852)	(87,050,704)

PacifiCorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2027

Exhibit PAC/802

	Tab 7	Tab 8	OR Allocated
	Tax Adjustments	Rate Base Adjustments	Results of Operations December 2027
1 Operating Revenues:			
2 General Business Revenues	-	-	1,793,305,491
3 Interdepartmental	-	-	-
4 Special Sales	-	-	54,006,161
5 Other Operating Revenues	-	-	74,085,068
6 Total Operating Revenues	-	-	1,921,396,720
7			
8 Operating Expenses:			
9 Steam Production	-	(494,486)	264,348,177
10 Nuclear Production	-	-	-
11 Hydro Production	-	(432,343)	13,378,082
12 Solar Production	-	-	232,196
13 Wind Production	-	2,262,348	10,283,870
14 Other Renewable Production	-	-	1,997,903
15 Other Power Supply	-	(211,104)	449,391,626
16 Transmission	-	-	91,307,111
17 Distribution	-	-	125,776,662
18 Customer Accounting	-	-	32,131,875
19 Customer Service & Info	-	-	5,324,067
20 Sales	-	-	-
21 Administrative & General	-	(676,297)	140,886,076
22			
23 Total O&M Expenses	-	448,117	1,135,057,645
24			
25 Depreciation	-	261,370	337,794,580
26 Amortization	-	(199,120)	(295,207)
27 Taxes Other Than Income	18,007,436	-	112,881,934
28 Income Taxes - Federal	(18,471,771)	2,618,998	(60,628,691)
29 Income Taxes - State	(8,506,891)	593,131	5,141,589
30 Income Taxes - Def Net	5,755,253	(8,343,109)	9,027,360
31 Investment Tax Credit Adj.	-	-	-
32 Misc Revenue & Expense	-	-	(104,716)
33			
34 Total Operating Expenses:	(3,215,973)	(4,620,613)	1,538,874,495
35			
36 Operating Rev For Return:	3,215,973	4,620,613	382,522,225
37			
38 Rate Base:			
39 Electric Plant In Service	-	746,381,682	11,726,376,909
40 Plant Held for Future Use	-	(4,968,037)	-
41 Misc Deferred Debits	-	(78,297,752)	93,002,614
42 Elec Plant Acq Adj	-	(20,914)	684,215
43 Pensions	-	(44,191,249)	-
44 Prepayments	-	-	51,058,541
45 Fuel Stock	-	9,975,858	89,834,980
46 Material & Supplies	-	-	239,908,978
47 Working Capital	(272,197)	317,583	62,523,353
48 Weatherization Loans	-	-	-
49 Misc Rate Base	-	(14,356,267)	(14,356,267)
50			
51 Total Electric Plant:	(272,197)	614,840,905	12,249,033,325
52			
53 Rate Base Deductions:			
54 Accum Prov For Deprec	-	31,261,081	(4,896,570,165)
55 Accum Prov For Amort	-	-	(45,207,495)
56 Accum Def Income Tax	(64,193,086)	55,910,370	(778,022,691)
57 Unamortized ITC	14,608	-	(26,013)
58 Customer Adv For Const	-	50,617,975	(88,409,248)
59 Customer Service Deposits	-	-	-
60 Misc Rate Base Deductions	28,621,485	-	(354,993,731)
61			
62 Total Rate Base Deductions	(35,556,993)	137,789,426	(6,163,229,344)
63			
64 Total Rate Base:	(35,829,190)	752,630,331	6,085,803,981
65			
66 Return on Rate Base	0.107%	-0.800%	6.285%
67			
68 Return on Equity	0.214%	-1.601%	7.161%
69			
70 TAX CALCULATION:			
71 Operating Revenue	(18,007,436)	(510,367)	336,062,484
72 Other Deductions			
73 Interest (AFUDC)	39,948,437	-	(2,826,222)
74 Interest	(969,180)	20,358,650	164,620,998
75 Schedule "M" Additions	(78,180,018)	(3,587,580)	329,762,524
76 Schedule "M" Deductions	(121,953,913)	(37,521,147)	401,633,646
77 Income Before Tax	(13,212,799)	13,064,549	102,396,587
78			
79 State Income Taxes	(8,506,891)	593,131	5,141,589
80 Taxable Income	(4,705,908)	12,471,418	97,254,998
81			
82 Federal Income Taxes + Other	(18,471,771)	2,618,998	(60,628,691)
APPROXIMATE PRICE CHANGE	(8,129,089)	71,699,814	106,039,093

Docket No. UE 470
Exhibit PAC/802
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Oregon Results of Operations – December 2027

May 2026

Tab 1 - Results

PacifiCorp **Page 1.0**
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2027

(1)	Test Period 2020 Protocol Revenue Requirement	1,899,344,584	Page 1.1
(2)	Normalized General Business Revenues	1,793,305,491	Page 1.1
(3)	2020 Protocol Price Change	**106,039,093**	Page 1.1

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2027

	(1)	(2) (3) - (1)	(3) Ref. Page 1.2	(4) **TAM**	(5) **GRC**	(6) (3) + (4) + (5)
	NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Price Change	Requested Non-NPC Related Price Change	Total Normalized Results with Price Change
1 Operating Revenues:						
2 General Business Revenues	561,429,046	1,231,876,445	1,793,305,491	(55,709,435)	161,748,527	1,899,344,584
3 Interdepartmental		-	-			-
4 Special Sales	54,006,161	-	54,006,161			54,006,161
5 Other Operating Revenues		74,085,068	74,085,068			74,085,068
6 Total Operating Revenues	615,435,207	1,305,961,513	1,921,396,720	(55,709,435)	161,748,527	2,027,435,813
7						
8 Operating Expenses:						
9 Steam Production	174,552,460	89,795,716	264,348,177			264,348,177
10 Nuclear Production		-	-			-
11 Hydro Production		13,378,082	13,378,082			13,378,082
12 Solar Production		232,196	232,196			232,196
13 Wind Production		10,283,870	10,283,870			10,283,870
14 Other Renewable Production	1,565,734	432,169	1,997,903			1,997,903
15 Other Power Supply	424,446,542	24,945,085	449,391,626			449,391,626
16 Transmission	66,612,911	24,694,200	91,307,111			91,307,111
17 Distribution		125,776,662	125,776,662			125,776,662
18 Customer Accounting		32,131,875	32,131,875		660,781	32,792,656
19 Customer Service & Info		5,324,067	5,324,067			5,324,067
20 Sales		-	-			-
21 Administrative & General		140,886,076	140,886,076			140,886,076
22						
23 Total O&M Expenses	667,177,647	467,879,998	1,135,057,645	-	660,781	1,135,718,426
24						
25 Depreciation		337,794,580	337,794,580			337,794,580
26 Amortization		(295,207)	(295,207)			(295,207)
27 Taxes Other Than Income		112,881,934	112,881,934		2,929,323	115,811,257
28 Income Taxes - Federal	(91,405,712)	30,777,021	(60,628,691)	(11,167,848)	31,705,386	(40,091,152)
29 Income Taxes - State	(2,349,107)	7,490,696	5,141,589	(2,529,208)	7,180,392	9,792,773
30 Income Taxes - Def Net		9,027,360	9,027,360			9,027,360
31 Investment Tax Credit Adj.		-	-			-
32 Misc Revenue & Expense		(104,716)	(104,716)			(104,716)
33						
34 Total Operating Expenses:	573,422,828	965,451,667	1,538,874,495	(13,697,056)	42,475,883	1,567,653,322
35						
36 Operating Rev For Return:	42,012,379	340,509,847	382,522,225	(42,012,379)	119,272,644	459,782,491
37						
38 Rate Base:						
39 Electric Plant In Service		11,726,376,909	11,726,376,909			11,726,376,909
40 Plant Held for Future Use		-	-			-
41 Misc Deferred Debits		93,002,614	93,002,614			93,002,614
42 Elec Plant Acq Adj		684,215	684,215			684,215
43 Pension		-	-			-
44 Prepayments		51,058,541	51,058,541			51,058,541
45 Fuel Stock		89,834,980	89,834,980			89,834,980
46 Material & Supplies		239,908,978	239,908,978			239,908,978
47 Working Capital		62,523,353	62,523,353			62,523,353
48 Weatherization Loans		-	-			-
49 Misc Rate Base		(14,356,267)	(14,356,267)			(14,356,267)
50						
51 Total Electric Plant:	-	12,249,033,325	12,249,033,325			12,249,033,325
52						
53 Rate Base Deductions:						
54 Accum Prov For Deprec		(4,896,570,165)	(4,896,570,165)			(4,896,570,165)
55 Accum Prov For Amort		(45,207,495)	(45,207,495)			(45,207,495)
56 Accum Def Income Tax		(778,022,691)	(778,022,691)			(778,022,691)
57 Unamortized ITC		(26,013)	(26,013)			(26,013)
58 Customer Adv For Const		(88,409,248)	(88,409,248)			(88,409,248)
59 Customer Service Deposits		-	-			-
60 Misc Rate Base Deductions		(354,993,731)	(354,993,731)			(354,993,731)
61						
62 Total Rate Base Deductions	-	(6,163,229,344)	(6,163,229,344)			(6,163,229,344)
63						
64 Total Rate Base:	-	6,085,803,981	6,085,803,981			6,085,803,981
65						
66 Return on Rate Base			6.285%			7.555%
67						
68 Return on Equity			7.161%			9.700%

Ref. Page 1.2

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2027

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	1,231,876,445	161,748,527	1,393,624,972
3	Interdepartmental	-		-
4	Special Sales	-		-
5	Other Operating Revenues	74,085,068		74,085,068
6	Total Operating Revenues	1,305,961,513	161,748,527	1,467,710,040
7				
8	Operating Expenses:			
9	Steam Production	89,795,716		89,795,716
10	Nuclear Production	-		-
11	Hydro Production	13,378,082		13,378,082
12	Solar Production	232,196		232,196
13	Wind Production	10,283,870		10,283,870
14	Other Renewable Production	432,169		432,169
15	Other Power Supply	24,945,085		24,945,085
16	Transmission	24,694,200		24,694,200
17	Distribution	125,776,662		125,776,662
18	Customer Accounting	32,131,875	660,781	32,792,656
19	Customer Service & Info	5,324,067		5,324,067
20	Sales	-		-
21	Administrative & General	140,886,076		140,886,076
22				
23	Total O&M Expenses	467,879,998	660,781	468,540,779
24				
25	Depreciation	337,794,580		337,794,580
26	Amortization	(295,207)		(295,207)
27	Taxes Other Than Income	112,881,934	2,929,323	115,811,257
28	Income Taxes - Federal	30,777,021	31,705,386	62,482,408
29	Income Taxes - State	7,490,696	7,180,392	14,671,089
30	Income Taxes - Def Net	9,027,360		9,027,360
31	Investment Tax Credit Adj.	-		-
32	Misc Revenue & Expense	(104,716)		(104,716)
33				
34	Total Operating Expenses:	965,451,667	42,475,883	1,007,927,550
35				
36	Operating Rev For Return:	340,509,847	119,272,644	459,782,491
37				
38	Rate Base:			
39	Electric Plant In Service	11,726,376,909		11,726,376,909
40	Plant Held for Future Use	-		-
41	Misc Deferred Debits	93,002,614		93,002,614
42	Elec Plant Acq Adj	684,215		684,215
43	Pension	-		-
44	Prepayments	51,058,541		51,058,541
45	Fuel Stock	89,834,980		89,834,980
46	Material & Supplies	239,908,978		239,908,978
47	Working Capital	62,523,353		62,523,353
48	Weatherization Loans	-		-
49	Misc Rate Base	(14,356,267)		(14,356,267)
50				
51	Total Electric Plant:	12,249,033,325		12,249,033,325
52				
53	Rate Base Deductions:			
54	Accum Prov For Deprec	(4,896,570,165)		(4,896,570,165)
55	Accum Prov For Amort	(45,207,495)		(45,207,495)
56	Accum Def Income Tax	(778,022,691)		(778,022,691)
57	Unamortized ITC	(26,013)		(26,013)
58	Customer Adv For Const	(88,409,248)		(88,409,248)
59	Customer Service Deposits	-		-
60	Misc Rate Base Deductions	(354,993,731)		(354,993,731)
61				
62	Total Rate Base Deductions	(6,163,229,344)		(6,163,229,344)
63				
64	Total Rate Base:	6,085,803,981		6,085,803,981
65				
66	Return on Rate Base	5.595%		7.555%
67				
68	Return on Equity	5.780%		9.700%
69				
70	TAX CALCULATION:			
71	Operating Revenue	387,804,924	158,158,423	545,963,347
72	Other Deductions			
73	Interest (AFUDC)	(2,826,222)	-	(2,826,222)
74	Interest	164,620,998	-	164,620,998
75	Schedule "M" Additions	329,762,524	-	329,762,524
76	Schedule "M" Deductions	401,633,646	-	401,633,646
77	Income Before Tax	154,139,027	158,158,423	312,297,450
78				
79	State Income Taxes	7,490,696	7,180,392	14,671,089
80	Taxable Income	146,648,331	150,978,031	297,626,361
81				
82	Federal Income Taxes + Other	30,777,021	31,705,386	62,482,408

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2027

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	561,429,046	(55,709,435)	505,719,611
3	Interdepartmental	-		-
4	Special Sales	54,006,161		54,006,161
5	Other Operating Revenues	-		-
6	Total Operating Revenues	615,435,207	(55,709,435)	559,725,772
7				
8	Operating Expenses:			
9	Steam Production	174,552,460		174,552,460
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Solar Production	-		-
13	Wind Production	-		-
14	Other Renewable Production	1,565,734		1,565,734
15	Other Power Supply	424,446,542		424,446,542
16	Transmission	66,612,911		66,612,911
17	Distribution	-		-
18	Customer Accounting	-	-	-
19	Customer Service & Info	-		-
20	Sales	-		-
21	Administrative & General	-		-
22				
23	Total O&M Expenses	667,177,647	-	667,177,647
24				
25	Depreciation	-		-
26	Amortization	-		-
27	Taxes Other Than Income	-	-	-
28	Income Taxes - Federal	(91,405,712)	(11,167,848)	(102,573,559)
29	Income Taxes - State	(2,349,107)	(2,529,208)	(4,878,315)
30	Income Taxes - Def Net	-		-
31	Investment Tax Credit Adj.	-		-
32	Misc Revenue & Expense	-		-
33				
34	Total Operating Expenses:	573,422,828	(13,697,056)	559,725,772
35				
36	Operating Rev For Return:	42,012,379	(42,012,379)	-
37				
38	Rate Base:			
39	Electric Plant In Service	-		-
40	Plant Held for Future Use	-		-
41	Misc Deferred Debits	-		-
42	Elec Plant Acq Adj	-		-
43	Pension	-		-
44	Prepayments	-		-
45	Fuel Stock	-		-
46	Material & Supplies	-		-
47	Working Capital	-		-
48	Weatherization Loans	-		-
49	Misc Rate Base	-		-
50				
51	Total Electric Plant:	-		-
52				
53	Rate Base Deductions:			
54	Accum Prov For Deprec	-		-
55	Accum Prov For Amort	-		-
56	Accum Def Income Tax	-		-
57	Unamortized ITC	-		-
58	Customer Adv For Const	-		-
59	Customer Service Deposits	-		-
60	Misc Rate Base Deductions	-		-
61				
62	Total Rate Base Deductions	-		-
63				
64	Total Rate Base:	-		-
65				
66	Return on Rate Base	N/A		N/A
67				
68	Return on Equity	N/A		N/A
69				
70	TAX CALCULATION:			
71	Operating Revenue	(51,742,440)	(55,709,435)	(107,451,875)
72	Other Deductions			
73	Interest (AFUDC)	-	-	-
74	Interest	-	-	-
75	Schedule "M" Additions	-	-	-
76	Schedule "M" Deductions	-	-	-
77	Income Before Tax	(51,742,440)	(55,709,435)	(107,451,875)
78				
79	State Income Taxes	(2,349,107)	(2,529,208)	(4,878,315)
80	Taxable Income	(49,393,333)	(53,180,226)	(102,573,559)
81				
82	Federal Income Taxes + Other	(10,372,600)	(11,167,848)	(21,540,447)

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2027

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,793,305,491	106,039,093	1,899,344,584
3	Interdepartmental	-		
4	Special Sales	54,006,161		
5	Other Operating Revenues	74,085,068		
6	Total Operating Revenues	1,921,396,720		
7				
8	Operating Expenses:			
9	Steam Production	264,348,177		
10	Nuclear Production	-		
11	Hydro Production	13,378,082		
12	Solar Production	232,196		
13	Wind Production	10,283,870		
14	Other Renewable Production	1,997,903		
15	Other Power Supply	449,391,626		
16	Transmission	91,307,111		
17	Distribution	125,776,662		
18	Customer Accounting	32,131,875	660,781	32,792,656
19	Customer Service & Info	5,324,067		
20	Sales	-		
21	Administrative & General	140,886,076		
22				
23	Total O&M Expenses	1,135,057,645		
24				
25	Depreciation	337,794,580		
26	Amortization	(295,207)		
27	Taxes Other Than Income	112,881,934	2,929,323	115,811,257
28	Income Taxes - Federal	(60,628,691)	20,537,539	(40,091,152)
29	Income Taxes - State	5,141,589	4,651,184	9,792,773
30	Income Taxes - Def Net	9,027,360		
31	Investment Tax Credit Adj.	-		
32	Misc Revenue & Expense	(104,716)		
33				
34	Total Operating Expenses:	1,538,874,495	28,778,827	1,567,653,322
35				
36	Operating Rev For Return:	382,522,225	77,260,265	459,782,491
37				
38	Rate Base:			
39	Electric Plant In Service	11,726,376,909		
40	Plant Held for Future Use	-		
41	Misc Deferred Debits	93,002,614		
42	Elec Plant Acq Adj	684,215		
43	Pensions	-		
44	Prepayments	51,058,541		
45	Fuel Stock	89,834,980		
46	Material & Supplies	239,908,978		
47	Working Capital	62,523,353		
48	Weatherization Loans	-		
49	Misc Rate Base	(14,356,267)		
50				
51	Total Electric Plant:	12,249,033,325	-	12,249,033,325
52				
53	Rate Base Deductions:			
54	Accum Prov For Deprec	(4,896,570,165)		
55	Accum Prov For Amort	(45,207,495)		
56	Accum Def Income Tax	(778,022,691)		
57	Unamortized ITC	(26,013)		
58	Customer Adv For Const	(88,409,248)		
59	Customer Service Deposits	-		
60	Misc Rate Base Deductions	(354,993,731)		
61				
62	Total Rate Base Deductions	(6,163,229,344)	-	(6,163,229,344)
63				
64	Total Rate Base:	6,085,803,981	-	6,085,803,981
65				
66	Return on Rate Base	6.285%		7.555%
67				
68	Return on Equity	7.161%		9.700%
69				
70	TAX CALCULATION:			
71	Operating Revenue	336,062,484	102,448,988	438,511,473
72	Other Deductions			
73	Interest (AFUDC)	(2,826,222)	-	(2,826,222)
74	Interest	164,620,998	-	164,620,998
75	Schedule "M" Additions	329,762,524	-	329,762,524
76	Schedule "M" Deductions	401,633,646	-	401,633,646
77	Income Before Tax	102,396,587	102,448,988	204,845,576
78				
79	State Income Taxes	5,141,589	4,651,184	9,792,773
80	Taxable Income	97,254,998	97,797,804	195,052,802
81				
82	Federal Income Taxes + Other	(60,628,691)	20,537,539	(40,091,152)

Ref. Page 2.2

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2027

Net Rate Base	$	6,085,803,981	Ref. Page 1.1
Return on Rate Base Requested		7.56%	Ref. Page 2.1
Revenues Required to Earn Requested Return		459,782,491	
Less Current Operating Revenues		(382,522,225)	
Increase to Current Revenues		77,260,265	
Net to Gross Bump-up		137.25%	
Price Change Required for Requested Return	$	106,039,093	
Requested Price Change	$	106,039,093	
Uncollectible Percent		0.623%	Ref. Page 1.3
Increased Uncollectible Expense	$	660,781	
Requested Price Change	$	106,039,093	
Franchise Tax		2.296%	Ref. Page 1.3
Revenue Tax		0.000%	Ref. Page 1.3
Resource Supplier Tax		0.106%	Ref. Page 1.3
PUC Fees Based on General Business Revenues		0.360%	Ref. Page 1.3
Increase Taxes Other Than Income	$	2,929,323	
Requested Price Change	$	106,039,093	
Uncollectible Expense		(660,781)	
Taxes Other Than Income		(2,929,323)	
Income Before Taxes	$	102,448,988	
State Effective Tax Rate		4.54%	Ref. Page 2.1
State Income Taxes	$	4,651,184	
Taxable Income	$	97,797,804	
Federal Income Tax Rate		21.00%	Ref. Page 2.1
Federal Income Taxes	$	20,537,539	
Operating Income		100.000%	
Net Operating Income		72.860%	Ref. Page 1.3
Net to Gross Bump-Up		137.25%	

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2027

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.623%	See Note (1) Below
Taxes Other - Franchise Tax	2.296%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier	0.106%	
PUC Fees Based on General Business Revenues	0.360%	
Sub-Total	96.614%	
State Income Tax @ 4.54%	4.386%	
Sub-Total	92.228%	
Federal Income Tax @ 21.00%	19.368%	
Net Operating Income	72.860%	

(1) Uncollectible Accounts =	11,174,954	Pg 2.11, OREGON Situs from Account 904
	1,793,305,491	Pg. 2.2, General Business Revenues

PacifiCorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2027

			Tab 3	Tab 4	Tab 5	Tab 6
	TOTAL COMPANY UNADJUSTED RESULTS JUNE 2025	OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2025	Revenue Adjustments	O&M Adjustments	Net Power Cost Adjustments	Depreciation & Amortization Adjustments
1 Operating Revenues:						
2 General Business Revenues	6,686,582,827	1,817,705,929	(24,444,721)	44,283	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	140,270,178	34,258,193	-	-	19,747,968	-
5 Other Operating Revenues	300,432,890	78,092,441	(4,007,373)	-	-	-
6 Total Operating Revenues	7,127,285,895	1,930,056,563	(28,452,094)	44,283	19,747,968	-
7						
8 Operating Expenses:						
9 Steam Production	1,139,769,280	309,090,420	-	7,201,933	(46,107,869)	(5,341,821)
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	50,837,074	14,110,122	-	(299,697)	-	-
12 Solar Production	208,052	208,052	-	24,144	-	-
13 Wind Production	27,619,506	7,665,953	-	355,570	-	-
14 Other Renewable Production	1,482,364	411,439	-	20,730	1,565,734	-
15 Other Power Supply	2,075,654,989	487,690,216	-	947,362	(39,034,848)	-
16 Transmission	289,030,036	79,976,259	-	(3,378,890)	14,709,743	-
17 Distribution	355,741,131	143,286,453	-	(17,509,790)	-	-
18 Customer Accounting	95,817,305	30,068,565	-	2,063,311	-	-
19 Customer Service & Info	237,560,141	4,961,172	-	362,895	-	-
20 Sales	-	-	-	-	-	-
21 Administrative & General	448,859,752	141,770,244	-	(167,125)	(40,745)	-
22						
23 Total O&M Expenses	4,722,579,629	1,219,238,893	-	(10,379,558)	(68,907,986)	(5,341,821)
24						
25 Depreciation	1,194,509,229	311,069,907	-	-	-	26,463,303
26 Amortization	46,386,797	11,605,919	-	-	-	(11,702,006)
27 Taxes Other Than Income	230,247,482	95,458,958	-	(584,460)	-	-
28 Income Taxes - Federal	(279,264,551)	(80,160,228)	(5,702,527)	21,089,675	17,780,254	2,216,908
29 Income Taxes - State	6,575,518	5,041,783	(1,291,464)	4,776,228	4,026,735	502,068
30 Income Taxes - Def Net	80,393,832	35,250,752	-	(25,408,597)	-	1,773,062
31 Investment Tax Credit Adj.	(363,488)	-	-	-	-	-
32 Misc Revenue & Expense	(5,597,257)	(1,384,747)	-	1,280,031	-	-
33						
34 Total Operating Expenses:	5,995,467,190	1,596,121,237	(6,993,991)	(9,226,682)	(47,100,997)	13,911,514
35						
36 Operating Rev For Return:	1,131,818,705	333,935,327	(21,458,103)	9,270,965	66,848,965	(13,911,514)
37						
38 Rate Base:						
39 Electric Plant In Service	38,550,771,333	10,979,995,227	-	-	-	-
40 Plant Held for Future Use	11,192,650	4,968,037	-	-	-	-
41 Misc Deferred Debits	1,963,844,323	171,300,366	-	-	-	-
42 Elec Plant Acq Adj	11,200,196	705,129	-	-	-	-
43 Pensions	158,341,112	44,191,249	-	-	-	-
44 Prepayments	174,702,384	51,058,541	-	-	-	-
45 Fuel Stock	297,728,656	79,859,122	-	-	-	-
46 Material & Supplies	671,506,101	239,908,978	-	-	-	-
47 Working Capital	211,067,996	72,749,385	(212,206)	452,140	(1,429,098)	(9,082,253)
48 Weatherization Loans	350,500,629	-	-	-	-	-
49 Misc Rate Base	-	-	-	-	-	-
50						
51 Total Electric Plant:	42,400,855,379	11,644,736,034	(212,206)	452,140	(1,429,098)	(9,082,253)
52						
53 Rate Base Deductions:						
54 Accum Prov For Deprec	(13,328,358,351)	(3,913,070,370)	-	-	-	(1,014,760,876)
55 Accum Prov For Amort	(163,684,346)	(46,856,104)	-	-	-	1,648,609
56 Accum Def Income Tax	(2,954,148,265)	(677,336,618)	-	(95,544,651)	-	3,141,294
57 Unamortized ITC	(1,946,575)	(40,621)	-	-	-	-
58 Customer Adv For Const	(333,031,816)	(139,027,223)	-	-	-	-
59 Customer Service Deposits	-	-	-	-	-	-
60 Misc Rate Base Deductions	(2,554,751,473)	(764,989,851)	-	385,972,065	-	(4,597,430)
61						
62 Total Rate Base Deductions	(19,335,920,826)	(5,541,320,788)	-	290,427,413	-	(1,014,568,403)
63						
64 Total Rate Base:	23,064,934,553	6,103,415,246	(212,206)	290,879,554	(1,429,098)	(1,023,650,656)
65						
66 Return on Rate Base		5.471%	-0.351%	-0.088%	1.047%	0.900%
67						
68 Return on Equity		5.533%	-0.703%	-0.176%	2.094%	1.800%
69						
70 TAX CALCULATION:						
71 Operating Revenue		294,067,633	(28,452,094)	9,728,270	88,655,954	(9,419,476)
72 Other Deductions						
73 Interest (AFUDC)		(42,774,659)	-	-	-	-
74 Interest		165,097,382	(5,740)	7,868,292	(38,657)	(27,689,750)
75 Schedule "M" Additions		418,741,622	-	-	-	(7,211,499)
76 Schedule "M" Deductions		664,451,978	-	(103,343,273)	-	-
77 Income Before Tax		(73,965,445)	(28,446,354)	105,203,251	88,694,612	11,058,775
78						
79 State Income Taxes		5,041,783	(1,291,464)	4,776,228	4,026,735	502,068
80 Taxable Income		(79,007,229)	(27,154,890)	100,427,023	84,667,876	10,556,706
81						
82 Federal Income Taxes + Other		(80,160,228)	(5,702,527)	21,089,675	17,780,254	2,216,908
APPROXIMATE PRICE CHANGE		174,550,317	29,446,997	17,419,609	(91,897,852)	(87,050,704)

PacifiCorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2027

		Tab 7	Tab 8	OR Allocated
		Tax Adjustments	Rate Base Adjustments	Results of Operations December 2027
1	Operating Revenues:			
2	General Business Revenues	-	-	1,793,305,491
3	Interdepartmental	-	-	-
4	Special Sales	-	-	54,006,161
5	Other Operating Revenues	-	-	74,085,068
6	Total Operating Revenues	-	-	1,921,396,720
7				
8	Operating Expenses:			
9	Steam Production	-	(494,486)	264,348,177
10	Nuclear Production	-	-	-
11	Hydro Production	-	(432,343)	13,378,082
12	Solar Production	-	-	232,196
13	Wind Production	-	2,262,348	10,283,870
14	Other Renewable Production	-	-	1,997,903
15	Other Power Supply	-	(211,104)	449,391,626
16	Transmission	-	-	91,307,111
17	Distribution	-	-	125,776,662
18	Customer Accounting	-	-	32,131,875
19	Customer Service & Info	-	-	5,324,067
20	Sales	-	-	-
21	Administrative & General	-	(676,297)	140,886,076
22				
23	Total O&M Expenses	-	448,117	1,135,057,645
24				
25	Depreciation	-	261,370	337,794,580
26	Amortization	-	(199,120)	(295,207)
27	Taxes Other Than Income	18,007,436	-	112,881,934
28	Income Taxes - Federal	(18,471,771)	2,618,998	(60,628,691)
29	Income Taxes - State	(8,506,891)	593,131	5,141,589
30	Income Taxes - Def Net	5,755,253	(8,343,109)	9,027,360
31	Investment Tax Credit Adj.	-	-	-
32	Misc Revenue & Expense	-	-	(104,716)
33				
34	Total Operating Expenses:	(3,215,973)	(4,620,613)	1,538,874,495
35				
36	Operating Rev For Return:	3,215,973	4,620,613	382,522,225
37				
38	Rate Base:			
39	Electric Plant In Service	-	746,381,682	11,726,376,909
40	Plant Held for Future Use	-	(4,968,037)	-
41	Misc Deferred Debits	-	(78,297,752)	93,002,614
42	Elec Plant Acq Adj	-	(20,914)	684,215
43	Pensions	-	(44,191,249)	-
44	Prepayments	-	-	51,058,541
45	Fuel Stock	-	9,975,858	89,834,980
46	Material & Supplies	-	-	239,908,978
47	Working Capital	(272,197)	317,583	62,523,353
48	Weatherization Loans	-	-	-
49	Misc Rate Base	-	(14,356,267)	(14,356,267)
50				
51	Total Electric Plant:	(272,197)	614,840,905	12,249,033,325
52				
53	Rate Base Deductions:			
54	Accum Prov For Deprec	-	31,261,081	(4,896,570,165)
55	Accum Prov For Amort	-	-	(45,207,495)
56	Accum Def Income Tax	(64,193,086)	55,910,370	(778,022,691)
57	Unamortized ITC	14,608	-	(26,013)
58	Customer Adv For Const	-	50,617,975	(88,409,248)
59	Customer Service Deposits	-	-	-
60	Misc Rate Base Deductions	28,621,485	-	(354,993,731)
61				
62	Total Rate Base Deductions	(35,556,993)	137,789,426	(6,163,229,344)
63				
64	Total Rate Base:	(35,829,190)	752,630,331	6,085,803,981
65				
66	Return on Rate Base	0.107%	-0.800%	6.285%
67				
68	Return on Equity	0.214%	-1.601%	7.161%
69				
70	TAX CALCULATION:			
71	Operating Revenue	(18,007,436)	(510,367)	336,062,484
72	Other Deductions			
73	Interest (AFUDC)	39,948,437	-	(2,826,222)
74	Interest	(969,180)	20,358,650	164,620,998
75	Schedule "M" Additions	(78,180,018)	(3,587,580)	329,762,524
76	Schedule "M" Deductions	(121,953,913)	(37,521,147)	401,633,646
77	Income Before Tax	(13,212,799)	13,064,549	102,396,587
78				
79	State Income Taxes	(8,506,891)	593,131	5,141,589
80	Taxable Income	(4,705,908)	12,471,418	97,254,998
81				
82	Federal Income Taxes + Other	(18,471,771)	2,618,998	(60,628,691)
	APPROXIMATE PRICE CHANGE	(8,129,089)	71,699,814	106,039,093

Tab 2 - Report

PacifiCorp
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	OREGON
PERIOD:	TWELVE MONTHS ENDING DECEMBER 31, 2027
FILE:	OR JAM Dec 2027 GRC
PREPARED BY:	Revenue Requirement Department
DATE:	4/22/2026
TIME:	5:04:38 PM
TYPE OF RATE BASE:	13-Month Average
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	50.00%	5.41%	2.71%
PREFERRED	0.00%	6.75%	0.00%
COMMON	50.00%	9.70%	4.85%
	100.00%		7.56%

OTHER INFORMATION

For information and support regarding capital structure and cost of debt, see testimony of M. Ryan Weems.
For information and support regarding return on common equity, see testimony of Ann E. Bulkley.

2020 PROTOCOL
13-Month Average

RESULTS OF OPERATIONS SUMMARY

	Description of Account Summary:	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
1	Operating Revenues					
2	General Business Revenues	2.2	6,686,582,827	1,817,705,929	6,662,182,389	1,793,305,491
3	Interdepartmental	2.2	0	0	0	0
4	Special Sales	2.2	140,270,178	34,258,193	70,898,832	54,006,161
5	Other Operating Revenues	2.3	300,432,890	78,092,441	285,994,780	74,085,068
6	Total Operating Revenues	2.3	7,127,285,895	1,930,056,563	7,019,076,002	1,921,396,720
7						
8	Operating Expenses:					
9	Steam Production	2.5	1,139,769,280	309,090,420	498,367,279	264,348,177
10	Nuclear Production	2.5	0	0	0	0
11	Hydro Production	2.6	50,837,074	14,110,122	48,199,621	13,378,082
12	Solar Production	2.6	208,052	208,052	232,196	232,196
13	Wind Production	2.6	27,619,506	7,665,953	37,051,549	10,283,870
14	Other Renewable Production	2.6	1,482,364	411,439	3,122,787	1,997,903
15	Other Power Supply	2.7, .8	2,075,654,989	487,690,216	833,424,602	449,391,626
16	Transmission	2.9	289,030,036	79,976,259	155,583,147	91,307,111
17	Distribution	2.10	355,741,131	143,286,453	349,264,972	125,776,662
18	Customer Accounting	2.11	95,817,305	30,068,565	100,540,869	32,131,875
19	Customer Service & Infor	2.12	237,560,141	4,961,172	248,676,556	5,324,067
20	Sales	2.12	0	0	0	0
21	Administrative & General	2.13	448,859,752	141,770,244	314,131,993	140,886,076
22						
23	Total O & M Expenses	2.13	4,722,579,629	1,219,238,893	2,588,595,571	1,135,057,645
24						
25	Depreciation	2.14	1,194,509,229	311,069,907	1,235,870,409	337,794,580
26	Amortization	2.15	46,386,797	11,605,919	22,421,726	(295,207)
27	Taxes Other Than Income	2.15	230,247,482	95,458,958	271,441,309	112,881,934
28	Income Taxes - Federal	2.18	(279,264,551)	(80,160,228)	411,715,574	(60,628,691)
29	Income Taxes - State	2.18	6,575,518	5,041,783	121,278,480	5,141,589
30	Income Taxes - Def Net	2.16	80,393,832	35,250,752	(96,399,478)	9,027,360
31	Investment Tax Credit Adj.	2.15	(363,488)	0	(514)	0
32	Misc Revenue & Expense	2.3	(5,597,257)	(1,384,747)	(1,011,940)	(104,716)
33						
34	Total Operating Expenses	2.18	5,995,467,190	1,596,121,237	4,553,911,138	1,538,874,495
35						
36	Operating Revenue for Return		1,131,818,705	333,935,327	2,465,164,863	382,522,225
37						
38	Rate Base:					
39	Electric Plant in Service	2.26	38,550,771,333	10,979,995,227	42,016,634,369	11,726,376,909
40	Plant Held for Future Use	2.26	11,192,650	4,968,037	0	0
41	Misc Deferred Debits	2.28	1,963,844,323	171,300,366	1,674,027,413	93,002,614
42	Elec Plant Acq Adj	2.26,.27	11,200,196	705,129	11,124,844	684,215
43	Pensions	2.27	158,341,112	44,191,249	0	0
44	Prepayments	2.28	174,702,384	51,058,541	174,702,384	51,058,541
45	Fuel Stock	2.27	297,728,656	79,859,122	334,920,385	89,834,980
46	Material & Supplies	2.28	671,506,101	239,908,978	671,506,101	239,908,978
47	Working Capital	2.28	211,067,996	72,749,385	154,423,410	62,523,353
48	Weatherization Loans	2.27	350,500,629	0	350,500,629	0
49	Miscellaneous Rate Base	2.29	0	0	(14,356,267)	(14,356,267)
50						
51	Total Electric Plant		42,400,855,379	11,644,736,034	45,373,483,268	12,249,033,325
52						
53	Rate Base Deductions:					
54	Accum Prov For Depr	2.32	(13,328,358,351)	(3,913,070,370)	(16,533,503,057)	(4,896,570,165)
55	Accum Prov For Amort	2.33	(163,684,346)	(46,856,104)	(158,023,373)	(45,207,495)
56	Accum Def Income Taxes	2.30	(2,954,148,265)	(677,336,618)	(3,175,774,720)	(778,022,691)
57	Unamortized ITC	2.30	(1,946,575)	(40,621)	(562,961)	(26,013)
58	Customer Adv for Const	2.29	(333,031,816)	(139,027,223)	(333,031,816)	(88,409,248)
59	Customer Service Deposits	2.29	0	0	0	0
60	Misc. Rate Base Deductions	2.29	(2,554,751,473)	(764,989,851)	(1,147,755,742)	(354,993,731)
61						
62	Total Rate Base Deductions		(19,335,920,826)	(5,541,320,788)	(21,348,651,670)	(6,163,229,344)
63						
64	Total Rate Base		23,064,934,553	6,103,415,246	24,024,831,598	6,085,803,981
65						
66	Return on Rate Base		4.907%	5.471%	10.261%	6.285%
67						
68	Return on Equity		4.404%	5.533%	15.112%	7.161%
69	Net Power Costs		2,542,913,493	690,058,224	613,171,486	613,171,486
70	100 Basis Points in Equity:		115,324,673	30,517,076	120,124,158	30,429,020
71	Revenue Requirement Impact		152,923,317	40,466,384	159,287,551	40,349,619
72	Rate Base Decrease		(2,132,838,996)	(511,063,686)	(1,116,301,753)	(448,442,892)

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
73	Sales to Ultimate Customers							
74	440	Residential Sales						
75			S		2,655,240,766	888,265,464	2,586,684,710	819,709,408
76								
77				B1	2,655,240,766	888,265,464	2,586,684,710	819,709,408
78								
79	442	Commercial & Industrial Sales						
80			S		4,014,684,187	924,041,985	4,060,400,129	969,757,928
81			SE		-	-	-	-
82			SG		-	-	-	-
83								
84								
85				B1	4,014,684,187	924,041,985	4,060,400,129	969,757,928
86								
87	444	Public Street & Highway Lighting						
88			S		16,657,874	5,398,480	15,097,550	3,838,155
89			SO		-	-	-	-
90				B1	16,657,874	5,398,480	15,097,550	3,838,155
91								
92	445	Other Sales to Public Authority						
93			S		-	-	-	-
94								
95				B1	-	-	-	-
96								
97	448	Interdepartmental						
98			S		-	-	-	-
99			SO		-	-	-	-
100				B1	-	-	-	-
101								
102	**Total Sales to Ultimate Customers**			**B1**	**6,686,582,827**	**1,817,705,929**	**6,662,182,389**	**1,793,305,491**
103								
104								
105								
106	447	Sales for Resale-Non NPC						
107			S		16,892,672	-	16,892,672	-
108				B1	16,892,672	-	16,892,672	-
109								
110	447NPC	Sales for Resale-NPC						
111			S		-	-	54,006,161	54,006,161
112			SE		(1,506,975)	(404,213)	-	-
113			SG		124,884,481	34,662,405	(0)	(0)
114				B1	123,377,506	34,258,193	54,006,161	54,006,161
115								
116		Total Sales for Resale		B1	140,270,178	34,258,193	70,898,832	54,006,161
117								
118	449	Provision for Rate Refund						
119			S		-	-	-	-
120			SG		-	-	-	-
121								
122								
123				B1	-	-	-	-
124								
125	**Total Sales from Electricity**			**B1**	**6,826,853,005**	**1,851,964,122**	**6,733,081,221**	**1,847,311,652**
126	450	Forfeited Discounts & Interest						
127			S		14,121,026	6,625,546	14,121,026	6,625,546
128			SO		-	-	-	-
129				B1	14,121,026	6,625,546	14,121,026	6,625,546
130								
131	451	Misc Electric Revenue						
132			S		9,187,867	551,000	9,187,867	551,000
133			SG		-	-	-	-
134			SO		68,001	18,978	68,001	18,978
135				B1	9,255,868	569,979	9,255,868	569,979
136								
137	453	Water Sales						
138			SG		5,895	1,636	5,895	1,636
139				B1	5,895	1,636	5,895	1,636
140								
141	454	Rent of Electric Property						
142			S		14,124,583	7,261,847	14,124,583	7,261,847
143			SG		2,219,479	616,029	2,219,479	616,029
144			SG		-	-	-	-
145			SO		3,732,305	1,041,645	3,732,305	1,041,645
146				B1	20,076,367	8,919,522	20,076,367	8,919,522

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
147								
148								
149								
150	456	Other Electric Revenue						
151			S		33,213,017	125,601	33,213,017	125,601
152			CN		-	-	-	-
153			SE		27,437,984	7,359,632	27,437,201	7,359,422
154			SO		14,636	4,085	14,636	4,085
155			SG		196,308,098	54,486,441	181,870,771	50,479,278
156								
157								
158				B1	256,973,735	61,975,758	242,535,625	57,968,385
159								
160	**Total Other Electric Revenues**			**B1**	**300,432,890**	**78,092,441**	**285,994,780**	**74,085,068**
161								
162	**Total Electric Operating Revenues**			**B1**	**7,127,285,895**	**1,930,056,563**	**7,019,076,002**	**1,921,396,720**
163								
164	Summary of Revenues by Factor							
165			S		6,774,121,991	1,832,269,925	6,803,727,713	1,861,875,647
166			CN		-	-	-	-
167			SE		25,931,009	6,955,419	27,437,201	7,359,422
168			SO		3,814,942	1,064,708	3,814,942	1,064,708
169			SG		323,417,953	89,766,511	184,096,145	51,096,943
170			DGP		-	-	-	-
171								
172	Total Electric Operating Revenues				7,127,285,895	1,930,056,563	7,019,076,002	1,921,396,720
173	Miscellaneous Revenues							
174	41160	Gain on Sale of Utility Plant - CR						
175			S		-	-	-	-
176			SG		-	-	-	-
177			SO		-	-	-	-
178			SG		-	-	-	-
179			SG		-	-	-	-
180				B1	-	-	-	-
181								
182	41170	Loss on Sale of Utility Plant						
183			S		-	-	-	-
184			SG		-	-	-	-
185				B1	-	-	-	-
186								
187	4118	Gain from Emission Allowances						
188			S		-	-	-	-
189			SE		(41)	(11)	(41)	(11)
190				B1	(41)	(11)	(41)	(11)
191								
192	41181	Gain from Disposition of NOX Credits						
193			SE		-	-	-	-
194				B1	-	-	-	-
195								
196	4194	Impact Housing Interest Income						
197			SG		-	-	-	-
198				B1	-	-	-	-
199								
200	421	(Gain) / Loss on Sale of Utility Plant						
201			S		246,124	246,124	246,124	246,124
202			SG		-	-	-	-
203			SG-P		21,315	5,916	21,315	5,916
204			CN		-	-	-	-
205			SO		(5,875,102)	(1,639,676)	(1,081,410)	(301,810)
206			SG		10,447	2,900	(197,928)	(54,936)
207				B1	(5,597,216)	(1,384,736)	(1,011,899)	(104,705)
208								
209	**Total Miscellaneous Revenues**			**B1**	**(5,597,257)**	**(1,384,747)**	**(1,011,940)**	**(104,716)**
210	Miscellaneous Expenses							
211	4311	Interest on Customer Deposits						
212			S		-	-	-	-
213					-	-	-	-
214	**Total Miscellaneous Expenses**			B1	**-**	**-**	**-**	**-**
215								
216	**Net Misc Revenue and Expense**			**B1**	**(5,597,257)**	**(1,384,747)**	**(1,011,940)**	**(104,716)**
217								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
218	500	Operation Supervision & Engineering						
219			SG		-	-	-	-
220			SG		-	-	-	-
221			SG		16,847,291	4,676,062	17,803,495	4,941,462
222				B2	16,847,291	4,676,062	17,803,495	4,941,462
223								
224	501	Fuel Related-Non NPC						
225			S		-	-	-	-
226			SE		22,159,971	5,943,922	3,416,237	916,330
227			SE		-	-	-	-
228			SE		-	-	-	-
229			SE		-	-	-	-
230				B2	22,159,971	5,943,922	3,416,237	916,330
231								
232	501NPC	Fuel Related-NPC						
233			S		(1,332,692)	-	174,552,460	174,552,460
234			SE		790,247,594	211,966,426	-	-
235			SE		-	-	-	-
236			SE		-	-	-	-
237			SE		-	-	-	-
238				B2	788,914,902	211,966,426	174,552,460	174,552,460
239								
240		Total Fuel Related		B2	811,074,873	217,910,347	177,968,697	175,468,790
241								
242	502	Steam Expenses						
243			SG		-	-	-	-
244			SG		-	-	-	-
245			SG		68,806,846	19,097,735	72,568,586	20,141,828
246				B2	68,806,846	19,097,735	72,568,586	20,141,828
247								
248	503	Steam From Other Sources-Non-NPC						
249			SE		-	-	702	188
250				B2	-	-	702	188
251								
252	503NPC	Steam From Other Sources-NPC						
253			S		-	-	-	-
254			SE		5,462,029	1,465,068	-	-
255				B2	5,462,029	1,465,068	-	-
256								
257	505	Electric Expenses						
258			SG		-	-	-	-
259			SG		-	-	-	-
260			SG		1,143,591	317,410	1,204,129	334,213
261				B2	1,143,591	317,410	1,204,129	334,213
262								
263	506	Misc. Steam Expense						
264			SG		-	-	-	-
265			SG		53,070,792	14,730,103	49,003,503	13,601,204
266			SE		-	-	5,261,096	1,411,173
267				B2	53,070,792	14,730,103	54,264,599	15,012,376
268								
269	507	Rents						
270			SG		-	-	-	-
271			SG		537,411	149,161	565,821	157,047
272			SG		-	-	-	-
273				B2	537,411	149,161	565,821	157,047
274								
275	509NPC	Allowances-NPC						
276			S		-	-	-	-
277			SG		26,044,626	7,228,836	-	-
278				B2	26,044,626	7,228,836	-	-
279								
280	510	Maint Supervision & Engineering						
281			SG		-	-	-	-
282			SG		-	-	-	-
283			SG		3,978,353	1,104,215	13,234,928	3,673,430
284				B2	3,978,353	1,104,215	13,234,928	3,673,430
285								
286								
287								
288	511	Maintenance of Structures						
289			SG		-	-	-	-
290			SG		-	-	-	-
291			SG		22,145,451	6,146,597	23,292,800	6,465,050
292				B2	22,145,451	6,146,597	23,292,800	6,465,050
293								
294	512	Maintenance of Boiler Plant						
295			SG		-	-	-	-
296			SG		-	-	-	-
297			SG		76,194,564	21,148,239	80,189,393	22,257,027
298				B2	76,194,564	21,148,239	80,189,393	22,257,027
299								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
300	513	Maintenance of Electric Plant						
301			SG		-	-	-	-
302			SG		-	-	-	-
303			SG		39,320,095	10,913,518	41,368,563	11,482,082
304				B2	39,320,095	10,913,518	41,368,563	11,482,082
305								
306	514	Maintenance of Misc. Steam Plant						
307			SG		-	-	-	-
308			SG		-	-	-	-
309			SG		15,143,359	4,203,126	15,905,566	4,414,681
310				B2	15,143,359	4,203,126	15,905,566	4,414,681
311								
312	**Total Steam Power Generation**			**B2**	**1,139,769,280**	**309,090,420**	**498,367,279**	**264,348,177**
313	517	Operation Super & Engineering						
314			SG		-	-	-	-
315				B2	-	-	-	-
316								
317	518	Nuclear Fuel Expense						
318			SE		-	-	-	-
319								
320				B2	-	-	-	-
321								
322	519	Coolants and Water						
323			SG		-	-	-	-
324				B2	-	-	-	-
325								
326	520	Steam Expenses						
327			SG		-	-	-	-
328				B2	-	-	-	-
329								
330								
331								
332	523	Electric Expenses						
333			SG		-	-	-	-
334				B2	-	-	-	-
335								
336	524	Misc. Nuclear Expenses						
337			SG		-	-	-	-
338				B2	-	-	-	-
339								
340	528	Maintenance Super & Engineering						
341			SG		-	-	-	-
342				B2	-	-	-	-
343								
344	529	Maintenance of Structures						
345			SG		-	-	-	-
346				B2	-	-	-	-
347								
348	530	Maintenance of Reactor Plant						
349			SG		-	-	-	-
350				B2	-	-	-	-
351								
352	531	Maintenance of Electric Plant						
353			SG		-	-	-	-
354				B2	-	-	-	-
355								
356	532	Maintenance of Misc Nuclear						
357			SG		-	-	-	-
358				B2	-	-	-	-
359								
360	**Total Nuclear Power Generation**			**B2**	**-**	**-**	**-**	**-**
361								
362	535	Operation Super & Engineering						
363			SG		9,487,725	2,633,373	9,927,399	2,755,407
364			SG		3,524,542	978,257	3,927,509	1,090,103
365			SG		-	-	(1,611,655)	(447,324)
366			SG		-	-	-	-
367			SG		-	-	-	-
368								
369				B2	13,012,267	3,611,630	12,243,253	3,398,185
370								
371	536	Water For Power						
372			SG		(134,016)	(37,197)	(137,665)	(38,210)
373			SG		-	-	-	-
374			SG		-	-	-	-
375								
376				B2	(134,016)	(37,197)	(137,665)	(38,210)
377								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
378	537	Hydraulic Expenses						
379			SG		5,399,465	1,498,653	5,604,357	1,555,522
380			SG		-	-	-	-
381			SG		-	-	-	-
382			SG		380,684	105,661	394,511	109,499
383				B2	5,780,149	1,604,314	5,998,868	1,665,020
384								
385	538	Electric Expenses						
386			DGP		-	-	-	-
387			SG		-	-	-	-
388			SG		-	-	-	-
389								
390				B2	-	-	-	-
391								
392	539	Misc. Hydro Expenses						
393			SG		-	-	-	-
394			SG		-	-	-	-
395			SG		-	-	-	-
396			SG		9,041,265	2,509,455	9,471,734	2,628,934
397			SG		9,588,005	2,661,206	10,055,396	2,790,933
398				B2	18,629,271	5,170,661	19,527,130	5,419,867
399								
400	540	Rents (Hydro Generation)						
401			SG		-	-	-	-
402			SG-P		1,566,710	434,849	1,621,020	449,923
403			SG-U		111,924	31,065	115,802	32,142
404								
405				B2	1,678,634	465,915	1,736,822	482,065
406								
407	541	Maint Supervision & Engineering						
408			SG		-	-	-	-
409			SG-P		381	106	397	110
410			SG-U		-	-	-	-
411								
412				B2	381	106	397	110
413								
414	542	Maintenance of Structures						
415			SG		48,957	13,588	51,255	14,226
416			SG		-	-	-	-
417			SG		-	-	-	-
418			SG		476,346	132,212	499,993	138,776
419				B2	525,303	145,801	551,248	153,002
420								
421								
422								
423								
424	543	Maintenance of Dams & Waterways						
425			SG		439,168	121,894	461,403	128,065
426			SG		-	-	-	-
427			SG		-	-	-	-
428			SG		636,824	176,754	666,319	184,941
429				B2	1,075,992	298,648	1,127,723	313,006
430								
431	544	Maintenance of Electric Plant						
432			SG		870,180	241,523	919,156	255,117
433			SG		-	-	-	-
434			SG		-	-	-	-
435			SG		684,630	190,023	716,051	198,744
436				B2	1,554,809	431,546	1,635,208	453,861
437								
438	545	Maintenance of Misc. Hydro Plant						
439			SG		4,367,284	1,212,165	4,567,312	1,267,684
440			SG		911,084	252,877	949,326	263,491
441			SG		3,435,915	953,658	-	-
442			SG		-	-	-	-
443			SG		-	-	-	-
444								
445				B2	8,714,283	2,418,699	5,516,638	1,531,175
446								
447	**Total Hydraulic Power Generation**			**B2**	**50,837,074**	**14,110,122**	**48,199,621**	**13,378,082**
448								
449								
450								
451								
452	558XP	Solar Power Expenses						
453			S		208,052	208,052	232,196	232,196
454			SG		-	-	-	-
455				B2	208,052	208,052	232,196	232,196
456								
457	**Total Solar Power Generation**			**B2**	**208,052**	**208,052**	**232,196**	**232,196**
458								
459								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
460								
461								
462	558WP	Wind Power Expenses						
463			S		-	-	-	-
464			SG		27,619,506	7,665,953	37,051,549	10,283,870
465				B2	27,619,506	7,665,953	37,051,549	10,283,870
466								
467	**Total Wind Power Generation**			**B2**	**27,619,506**	**7,665,953**	**37,051,549**	**10,283,870**
468								
469								
470								
471								
472	559NPC	Other Renewable Fuel						
473			S		-	-	1,565,734	1,565,734
474			SE		-	-	-	-
475				B2	-	-	1,565,734	1,565,734
476								
477	559	Other Renewable Expenses						
478			S		-	-	-	-
479			SG		1,482,364	411,439	1,557,054	432,169
480				B2	1,482,364	411,439	1,557,054	432,169
481								
482	**Total Other Renewable Generation**			**B2**	**1,482,364**	**411,439**	**3,122,787**	**1,997,903**
483								
484	546	Operation Super & Engineering						
485			SG		-	-	-	-
486			SG		-	-	-	-
487			SG		460,563	127,832	481,578	133,665
488				B2	460,563	127,832	481,578	133,665
489								
490	547	Fuel-Non-NPC						
491			SE		-	-	-	-
492			SE		-	-	-	-
493				B2	-	-	-	-
494								
495	547NPC	Fuel-NPC						
496			S		-	-	140,545,976	140,545,976
497			SE		394,476,811	105,809,673	-	-
498				B2	394,476,811	105,809,673	140,545,976	140,545,976
499								
500	548	Generation Expense						
501			SG		-	-	-	-
502			SG		-	-	-	-
503			SG		29,536,939	8,198,147	31,023,641	8,610,790
504				B2	29,536,939	8,198,147	31,023,641	8,610,790
505								
506	549	Miscellaneous Other						
507			S		19,939	19,939	21,060	21,060
508			SG		-	-	-	-
509			SG		-	-	-	-
510			SG		7,865,651	2,183,157	8,237,957	2,286,492
511			SG		-	-	-	-
512				B2	7,885,590	2,203,096	8,259,017	2,307,552
513								
514								
515								
516								
517	550	Rents						
518			S		184,618	184,618	193,512	193,512
519			SG		3,586,009	995,317	3,758,773	1,043,269
520			SG		-	-	-	-
521			SG		-	-	-	-
522				B2	3,770,627	1,179,936	3,952,286	1,236,782
523								
524	551	Maint Supervision & Engineering						
525			SG		-	-	-	-
526				B2	-	-	-	-
527								
528	552	Maintenance of Structures						
529			SG		-	-	-	-
530			SG		-	-	-	-
531			SG		2,889,286	801,938	3,040,690	843,961
532				B2	2,889,286	801,938	3,040,690	843,961
533								
534	553	Maint of Generation & Electric Plant						
535			SG		-	-	-	-
536			SG		-	-	-	-
537			SG		-	-	-	-
538			SG		23,452,725	6,509,439	20,737,051	5,755,688
539				B2	23,452,725	6,509,439	20,737,051	5,755,688
540								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
541	554	Maintenance of Misc.	Other					
542			SG		-	-	-	-
543			SG		-	-	-	-
544			SG		-	-	-	-
545			SG		5,897,969	1,637,015	6,185,154	1,716,725
546				B2	5,897,969	1,637,015	6,185,154	1,716,725
547								
548	**Total Other Power Generation**			**B2**	**468,370,511**	**126,467,075**	**214,225,393**	**161,151,138**
549								
550								
551	555	Purchased Power-Non NPC						
552			S		285,964,068	-	285,964,068	-
553					285,964,068	-	285,964,068	-
554								
555	555NPC	Purchased Power-NPC						
556			S		20,880,625	868,834	283,900,565	283,900,565
557			SE		(18,915,422)	(5,073,643)	(0)	(0)
558		Seasonal Contracts	SG		1,261,541,362	350,148,055	-	-
559			DGP		-	-	-	-
560					1,263,506,564	345,943,246	283,900,565	283,900,565
561								
562		Total Purchased Power		B2	1,549,470,632	345,943,246	569,864,633	283,900,565
563								
564	556	System Control & Load Dispatch						
565			SG		3,306,836	917,831	3,473,284	964,030
566								
567				B2	3,306,836	917,831	3,473,284	964,030
568								
569								
570								
571	557	Other Expenses						
572			S		16,100,253	11,880,923	4,496,880	73,841
573			SG		48,562,765	13,478,875	51,520,013	14,299,676
574			SGCT		-	-	-	-
575			SE		8,450	2,266	8,857	2,376
576			SG		-	-	-	-
577			TROJP		-	-	-	-
578								
579				B2	64,671,468	25,362,064	56,025,750	14,375,893
580								
581	Embedded Cost Differentials							
582	Company Owned Hydro		DGP		-	-	-	-
583	Company Owned Hydro		SG		-	-	-	-
584	Mid-C Contract		MC		-	-	-	-
585	Mid-C Contract		SG		-	-	-	-
586	Existing QF Contracts		S		-	-	-	-
587	Existing QF Contracts		SG		-	-	-	-
588								
589					-	-	-	-
590								
591								
592								
593								
594	2020 Protocol Adjustment							
595	Baseline ECD		S		(10,164,458)	(11,000,000)	(10,164,458)	(11,000,000)
596			S		-	-	-	-
597	2020 Protocol Adjustment				(10,164,458)	(11,000,000)	(10,164,458)	(11,000,000)
598								
599	**Total Other Power Supply**			**B2**	**1,607,284,479**	**361,223,141**	**619,199,209**	**288,240,488**
600								
601	**Total Production Expense**			**B2**	**3,295,571,265**	**819,176,201**	**1,420,398,034**	**739,631,854**
602								
603								
604	Summary of Production Expense by Factor							
605		S			311,860,405	2,162,366	881,307,994	590,085,345
606		SG			1,788,592,413	496,434,103	528,665,931	146,734,267
607		SE			1,193,439,432	320,113,712	8,686,891	2,330,066
608		SNPPH			-	-	-	-
609		TROJP			-	-	-	-
610		SGCT			-	-	-	-
611		DGP			-	-	-	-
612		DEU			-	-	-	-
613		DEP			-	-	-	-
614		SNPPS			-	-	-	-
615		SNPPO			-	-	-	-
616		DGU			-	-	-	-
617		MC			-	-	-	-
618		SSGCT			-	-	-	-
619		SSECT			-	-	-	-
620		SSGC			-	-	-	-
621		SSGCH			-	-	-	-

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
622		SSECH			-	-	-	-
623	Total Production Expense by Factor				3,293,892,250	818,710,181	1,418,660,816	739,149,679
624	560	Operation Supervision & Engineering						
625			SG		-	-	-	-
626			SG		14,010,564	3,888,712	14,741,288	4,091,529
627								
628				B2	14,010,564	3,888,712	14,741,288	4,091,529
629								
630	561	Load Dispatching						
631			SG		-	-	-	-
632			SG		21,603,066	5,996,055	22,694,126	6,298,885
633								
634				B2	21,603,066	5,996,055	22,694,126	6,298,885
635	562	Station Expense						
636			SG		-	-	-	-
637			SG		3,595,033	997,822	3,784,537	1,050,420
638								
639				B2	3,595,033	997,822	3,784,537	1,050,420
640								
641	563	Overhead Line Expense						
642			SG		-	-	-	-
643			SG		1,731,428	480,568	1,811,060	502,670
644								
645				B2	1,731,428	480,568	1,811,060	502,670
646								
647	564	Underground Line Expense						
648			SG		-	-	-	-
649								
650				B2	-	-	-	-
651								
652	565	Transmission of Electricity by Others						
653			SG		-	-	-	-
654			SE		-	-	-	-
655					-	-	-	-
656								
657	565NPC	Transmission of Electricity by Others-NPC						
658			S		-	-	66,612,911	66,612,911
659			SG		161,546,869	44,838,262	-	-
660			SE		26,339,197	7,064,907	-	-
661					187,886,066	51,903,168	66,612,911	66,612,911
662								
663		Total Transmission of Electricity by		B2	187,886,066	51,903,168	66,612,911	66,612,911
664								
665	566	Misc. Transmission Expense						
666			SG		-	-	-	-
667			SG		4,273,876	1,186,239	4,440,328	1,232,439
668								
669				B2	4,273,876	1,186,239	4,440,328	1,232,439
670								
671	567	Rents - Transmission						
672			SG		-	-	-	-
673			SG		2,391,502	663,775	2,487,885	690,527
674								
675				B2	2,391,502	663,775	2,487,885	690,527
676								
677	568	Maint Supervision & Engineering						
678			SG		-	-	-	-
679			SG		1,745,911	484,588	1,838,820	510,375
680								
681				B2	1,745,911	484,588	1,838,820	510,375
682								
683	569	Maintenance of Structures						
684			SG		-	-	-	-
685			SG		7,440,760	2,065,226	7,814,849	2,169,056
686								
687				B2	7,440,760	2,065,226	7,814,849	2,169,056
688								
689	570	Maintenance of Station Equipment						
690			SG		-	-	-	-
691			SG		13,885,779	3,854,078	14,609,218	4,054,873
692								
693				B2	13,885,779	3,854,078	14,609,218	4,054,873
694								
695	571	Maintenance of Overhead Lines						
696			SG		-	-	-	-
697			SG		30,031,808	8,335,501	14,295,018	3,967,664
698								
699				B2	30,031,808	8,335,501	14,295,018	3,967,664
700								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
701	572	Maintenance of Underground Lines						
702			SG		-	-	-	-
703			SG		118,336	32,845	123,491	34,276
704								
705				B2	118,336	32,845	123,491	34,276
706								
707	573	Maint of Misc. Transmission Plant						
708			SG		-	-	-	-
709			SG		315,906	87,682	329,615	91,487
710								
711				B2	315,906	87,682	329,615	91,487
712								
713	**Total Transmission Expense**			**B2**	**289,030,036**	**79,976,259**	**155,583,147**	**91,307,111**
714								
715	Summary of Transmission Expense by Factor							
716		SE			26,339,197	7,064,907	-	-
717		SG			262,690,839	72,911,352	88,970,236	24,694,200
718		SNPT			-	-	-	-
719	Total Transmission Expense by Factor				289,030,036	79,976,259	88,970,236	24,694,200
720	580	Operation Supervision & Engineering						
721			S		8,510,359	5,238,898	8,941,384	5,491,556
722			SNPD		7,436,503	1,902,116	7,786,584	1,991,660
723				B2	15,946,862	7,141,014	16,727,968	7,483,215
724								
725	581	Load Dispatching						
726			S		-	-	-	-
727			SNPD		17,221,992	4,405,057	18,223,846	4,661,312
728				B2	17,221,992	4,405,057	18,223,846	4,661,312
729								
730	582	Station Expense						
731			S		5,998,719	1,253,856	6,299,785	1,316,622
732			SNPD		475	121	496	127
733				B2	5,999,193	1,253,977	6,300,281	1,316,749
734								
735	583	Overhead Line Expenses						
736			S		12,755,247	1,451,878	13,465,834	1,545,622
737			SNPD		-	-	-	-
738				B2	12,755,247	1,451,878	13,465,834	1,545,622
739								
740	584	Underground Line Expense						
741			S		-	-	-	-
742			SNPD		-	-	-	-
743				B2	-	-	-	-
744								
745	585	Street Lighting & Signal Systems						
746			S		-	-	-	-
747			SNPD		305,498	78,141	322,655	82,529
748				B2	305,498	78,141	322,655	82,529
749								
750	586	Meter Expenses						
751			S		4,116,775	1,510,075	4,344,665	1,594,087
752			SNPD		10,348	2,647	10,938	2,798
753				B2	4,127,123	1,512,722	4,355,603	1,596,884
754								
755	587	Customer Installation Expenses						
756			S		20,968,733	7,107,810	22,111,871	7,502,020
757			SNPD		-	-	-	-
758				B2	20,968,733	7,107,810	22,111,871	7,502,020
759								
760	588	Misc. Distribution Expenses						
761			S		108,237	(773,986)	110,566	(816,416)
762			SNPD		(1,684,444)	(430,849)	(1,419,284)	(363,026)
763				B2	(1,576,206)	(1,204,835)	(1,308,718)	(1,179,442)
764								
765	589	Rents						
766			S		3,322,110	1,845,550	3,478,670	1,929,572
767			SNPD		572,374	146,402	598,109	152,985
768				B2	3,894,484	1,991,952	4,076,778	2,082,557
769								
770	590	Maint Supervision & Engineering						
771			S		4,945,093	1,455,857	5,194,702	1,529,238
772			SNPD		4,177,755	1,068,590	4,341,998	1,110,600
773				B2	9,122,848	2,524,447	9,536,700	2,639,838
774								
775	591	Maintenance of Structures						
776			S		3,440,909	1,406,252	3,589,410	1,466,942
777			SNPD		131,421	33,615	137,107	35,069
778				B2	3,572,330	1,439,867	3,726,518	1,502,011
779								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
780	592	Maintenance of Station Equipment						
781			S		13,022,817	5,063,811	13,705,368	5,335,515
782			SNPD		3,313,708	847,583	3,451,746	882,891
783				B2	16,336,524	5,911,394	17,157,114	6,218,406
784	593	Maintenance of Overhead Lines						
785			S		189,775,619	94,395,621	174,475,861	74,287,728
786			SNPD		3,725,705	952,964	3,910,009	1,000,106
787				B2	193,501,323	95,348,585	178,385,869	75,287,834
788								
789	594	Maintenance of Underground Lines						
790			S		42,135,120	10,893,801	44,227,046	11,445,031
791			SNPD		7,713	1,973	8,115	2,076
792				B2	42,142,834	10,895,774	44,235,161	11,447,107
793								
794	595	Maintenance of Line Transformers						
795			S		-	-	-	-
796			SNPD		1,046,180	267,593	1,102,327	281,954
797				B2	1,046,180	267,593	1,102,327	281,954
798								
799	596	Maint of Street Lighting & Signal Sys.						
800			S		2,002,490	823,527	2,105,754	867,844
801			SNPD		-	-	-	-
802				B2	2,002,490	823,527	2,105,754	867,844
803								
804	597	Maintenance of Meters						
805			S		735,198	216,151	775,339	228,077
806			SNPD		(149,492)	(38,237)	(158,709)	(40,595)
807				B2	585,707	177,914	616,630	187,482
808								
809	598	Maint of Misc. Distribution Plant						
810			S		3,405,981	1,038,810	3,553,445	1,083,990
811			SNPD		4,381,985	1,120,828	4,569,337	1,168,749
812				B2	7,787,966	2,159,638	8,122,781	2,252,739
813								
814	**Total Distribution Expense**			**B2**	**355,741,131**	**143,286,453**	**349,264,972**	**125,776,662**
815								
816								
817	Summary of Distribution Expense by Factor							
818		S			315,243,409	132,927,909	306,379,698	114,807,428
819		SNPD			40,497,721	10,358,544	42,885,274	10,969,234
820								
821	Total Distribution Expense by Factor				355,741,131	143,286,453	349,264,972	125,776,662
822								
823	901	Supervision						
824			S		-	-	-	-
825			CN		21,093,168	6,357,428	22,295,366	6,719,767
826				B2	21,093,168	6,357,428	22,295,366	6,719,767
827								
828	902	Meter Reading Expense						
829			S		7,923,233	2,037,297	8,372,328	2,151,766
830			CN		1,262,417	380,489	1,333,409	401,886
831				B2	9,185,650	2,417,786	9,705,738	2,553,652
832								
833	903	Customer Receipts & Collections						
834			S		9,382,691	972,048	11,146,428	2,270,062
835			CN		29,851,916	8,997,292	31,241,046	9,415,973
836				B2	39,234,607	9,969,340	42,387,475	11,686,034
837								
838	904	Uncollectible Accounts						
839			S		26,312,281	11,326,542	26,160,692	11,174,954
840			SG		-	-	-	-
841			CN		(8,401)	(2,532)	(8,401)	(2,532)
842				B2	26,303,880	11,324,010	26,152,291	11,172,422
843								
844	905	Misc. Customer Accounts Expense						
845			S		0	0	0	0
846			CN		-	-	-	-
847				B2	0	0	0	0
848								
849	**Total Customer Accounts Expense**			**B2**	**95,817,305**	**30,068,565**	**100,540,869**	**32,131,875**
850								
851	Summary of Customer Accts Exp by Factor							
852		S			43,618,205	14,335,887	45,679,449	15,596,781
853		CN			52,199,100	15,732,677	54,861,420	16,535,094
854		SG			-	-	-	-
855	Total Customer Accounts Expense by Factor				95,817,305	30,068,565	100,540,869	32,131,875
856								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
857	907	Supervision						
858			S		-	-	-	-
859			CN		-	-	-	-
860				B2	-	-	-	-
861								
862	908	Customer Assistance						
863			S		228,167,835	2,214,426	238,785,971	2,328,091
864			CN		4,024,825	1,213,072	4,236,323	1,276,817
865								
866								
867				B2	232,192,660	3,427,498	243,022,294	3,604,908
868								
869	909	Informational & Instructional Adv						
870			S		1,793,437	456,466	2,147,201	662,140
871			CN		3,419,806	1,030,721	3,344,728	1,008,093
872				B2	5,213,243	1,487,187	5,491,929	1,670,232
873								
874	910	Misc. Customer Service						
875			S		-	-	-	-
876			CN		154,238	46,487	162,332	48,927
877								
878				B2	154,238	46,487	162,332	48,927
879								
880	**Total Customer Service Expense**			**B2**	**237,560,141**	**4,961,172**	**248,676,556**	**5,324,067**
881								
882								
883	Summary of Customer Service Exp by Factor							
884		S			229,961,272	2,670,892	240,933,172	2,990,231
885		CN			7,598,869	2,290,280	7,743,384	2,333,836
886								
887	Total Customer Service Expense by Factor			B2	237,560,141	4,961,172	248,676,556	5,324,067
888								
889								
890	911	Supervision						
891			S		-	-	-	-
892			CN		-	-	-	-
893				B2	-	-	-	-
894								
895	912	Demonstration & Selling Expense						
896			S		-	-	-	-
897			CN		-	-	-	-
898				B2	-	-	-	-
899								
900	913	Advertising Expense						
901			S		-	-	-	-
902			CN		-	-	-	-
903				B2	-	-	-	-
904								
905	916	Misc. Sales Expense						
906			S		-	-	-	-
907			CN		-	-	-	-
908				B2	-	-	-	-
909								
910	**Total Sales Expense**			**B2**	**-**	**-**	**-**	**-**
911								
912								
913	Total Sales Expense by Factor							
914		S			-	-	-	-
915		CN			-	-	-	-
916	Total Sales Expense by Factor				-	-	-	-
917								
918	**Total Customer Service Exp Including Sales**			**B2**	**237,560,141**	**4,961,172**	**248,676,556**	**5,324,067**
919	920	Administrative & General Salaries						
920			S		24,494	(24,954)	49,671	(2,494)
921			CN		-	-	-	-
922			SO		88,243,480	24,627,777	93,332,638	26,048,105
923				B2	88,267,973	24,602,823	93,382,308	26,045,611
924								
925	921	Office Supplies & expenses						
926			S		660,927	500,213	35,487	(134,135)
927			CN		116,929	35,242	123,410	37,195
928			SO		13,955,774	3,894,902	21,284,582	5,940,291
929				B2	14,733,630	4,430,357	21,443,479	5,843,351
930								
931	922	A&G Expenses Transferred						
932			S		-	-	-	-
933			CN		-	-	-	-
934			SO		(45,396,046)	(12,669,533)	(48,264,904)	(13,470,200)
935				B2	(45,396,046)	(12,669,533)	(48,264,904)	(13,470,200)
936								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
937	923	Outside Services						
938			S		1,694,514	(635,743)	2,486,532	77,189
939			CN		-	-	-	-
940			SO		48,399,504	13,507,765	50,042,122	13,966,201
941				B2	50,094,018	12,872,022	52,528,654	14,043,390
942								
943	924	Property Insurance						
944			S		18,778,670	14,379,402	48,633,919	44,234,652
945			SG		-	-	-	-
946			SO		6,153,937	1,717,496	5,519,539	1,540,442
947				B2	24,932,607	16,096,898	54,153,458	45,775,094
948								
949	925	Injuries & Damages						
950			S		5,087,786	5,087,786	26,193,033	26,193,033
951			SO		256,259,948	71,519,311	54,915,137	15,326,206
952				B2	261,347,734	76,607,096	81,108,170	41,519,239
953								
954	926	Employee Pensions & Benefits						
955			S		1,224,653	536,407	1,224,653	536,407
956			SG		-	-	-	-
957			SO		141,471,619	39,483,161	146,974,636	41,018,992
958				B2	142,696,271	40,019,568	148,199,288	41,555,399
959								
960	927	Franchise Requirements						
961			S		-	-	-	-
962			SO		-	-	-	-
963				B2	-	-	-	-
964								
965	928	Regulatory Commission Expense						
966			S		27,082,638	11,798,603	28,177,530	12,221,673
967			SE		-	-	-	-
968			SO		2,687,052	749,926	2,807,554	783,557
969			SG		4,665,450	1,294,923	4,871,219	1,352,035
970				B2	34,435,140	13,843,452	35,856,303	14,357,265
971								
972	929	Duplicate Charges						
973			S		-	-	-	-
974			SO		(164,329,933)	(45,862,663)	(165,119,150)	(46,082,924)
975				B2	(164,329,933)	(45,862,663)	(165,119,150)	(46,082,924)
976								
977	930	Misc General Expenses						
978			S		72,190	3,026	(226,914)	(298,614)
979			CN		-	-	-	-
980			SG		-	-	(1,649,132)	(457,726)
981			SO		2,455,554	685,318	1,496,273	417,593
982				B2	2,527,744	688,344	(379,773)	(338,747)
983								
984	931	Rents						
985			S		122,650	89,979	116,895	83,392
986			SO		639,347	178,435	655,603	182,971
987				B2	761,997	268,413	772,498	266,364
988								
989	935	Maintenance of General Plant						
990			S		935,567	307,245	1,019,069	365,103
991			CN		83,150	25,061	86,540	26,083
992			SO		37,769,900	10,541,160	39,346,052	10,981,047
993				B2	38,788,617	10,873,467	40,451,661	11,372,233
994								
995	**Total Administrative & General Expense**			**B2**	**448,859,752**	**141,770,244**	**314,131,993**	**140,886,076**
996								
997	Summary of A&G Expense by Factor							
998		S			55,684,088	32,041,964	107,709,875	83,276,207
999		SE			-	-	-	-
1000		SO			388,310,135	108,373,054	202,990,081	56,652,282
1001		SG			4,665,450	1,294,923	3,222,087	894,309
1002		CN			200,079	60,303	209,950	63,278
1003	Total A&G Expense by Factor				448,859,752	141,770,244	314,131,993	140,886,076
1004								
1005	**Total O&M Expense**			**B2**	**4,722,579,629**	**1,219,238,893**	**2,588,595,571**	**1,135,057,645**
1006	403SP	Steam Depreciation						
1007			S		77,177,362	-	-	-
1008			SG		-	-	-	-
1009			SG		-	-	-	-
1010			SG		355,618,762	98,704,031	314,798,531	87,374,141
1011			SG		-	-	-	-
1012				B3	432,796,124	98,704,031	314,798,531	87,374,141
1013								
1014	403NP	Nuclear Depreciation						
1015			SG		-	-	-	-
1016				B3	-	-	-	-
1017								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
1018	403HP	Hydro Depreciation						
1019			SG		-	-	-	-
1020			SG		-	-	-	-
1021			SG		22,849,053	6,341,886	31,451,236	8,729,471
1022			SG		9,382,050	2,604,042	10,812,805	3,001,156
1023			SG		288,077	79,957	4,163,031	1,155,473
1024				B3	32,519,180	9,025,885	46,427,073	12,886,101
1025								
1026	403XP	Solar Depreciation						
1027			S		13,548	1,859	152,271	126,881
1028			SG		-	-	-	-
1029				B3	13,548	1,859	152,271	126,881
1030								
1031	403WP	Wind Depreciation						
1032			S		-	-	-	-
1033			SG		72,060,853	20,000,904	189,581,254	52,619,366
1034				B3	72,060,853	20,000,904	189,581,254	52,619,366
1035								
1036	403RP	Other Renewable Depreciation						
1037			S		-	-	-	-
1038			SG		2,516,034	698,340	3,023,588	839,214
1039				B3	2,516,034	698,340	3,023,588	839,214
1040								
1041	403OP	Other Production Depreciation						
1042			S		14,042	86	-	-
1043			SG		-	-	-	-
1044			SG		162,249,796	45,033,363	75,499,184	20,955,232
1045			SG		-	-	-	-
1046			SG		-	-	-	-
1047				B3	162,263,838	45,033,449	75,499,184	20,955,232
1048								
1049	403TP	Transmission Depreciation						
1050			S		(1,001,441)	-	(0)	(0)
1051			SG		-	-	-	-
1052			SG		-	-	-	-
1053			SG		180,407,540	50,073,150	217,813,885	60,455,495
1054				B3	179,406,099	50,073,150	217,813,885	60,455,495
1055								
1056								
1057								
1058	403	Distribution Depreciation						
1059	360	Land & Land Rights	S		553,088	74,505	993,008	157,551
1060	361	Structures	S		2,725,027	602,540	3,563,401	760,804
1061	362	Station Equipment	S		32,743,321	8,998,961	42,287,755	10,314,403
1062	362	Station Equipment	SG		1,463	406	-	-
1063	363	Storage Battery Equipment	S		3,530,997	1,294,507	4,657,790	1,507,218
1064	363	Storage Battery Equipment	SNPD		612,423	156,646	1,086,539	277,916
1065	363	Storage Battery Equipment	SO		-	-	-	-
1066	363	Storage Battery Equipment	SG		-	-	-	-
1067	364	Poles & Towers	S		60,290,805	18,675,108	70,217,547	20,549,030
1068	364	Poles & Towers	SG		-	-	-	-
1069	364	Poles & Towers	SNPD		-	-	-	-
1070	364	Poles & Towers	SO		-	-	-	-
1071	365	OH Conductors	S		27,204,166	8,329,981	33,581,971	9,533,952
1072	366	UG Conduit	S		12,123,442	2,279,015	15,083,951	2,837,885
1073	367	UG Conductor	S		24,481,058	5,003,649	31,297,392	6,290,403
1074	368	Line Trans	S		41,264,557	12,834,268	50,132,244	14,099,495
1075	369	Services	S		25,467,137	8,000,932	31,488,271	9,137,572
1076	370	Meters	S		13,845,467	1,894,191	15,574,330	2,220,557
1077	371	Inst Cust Prem	S		465,711	118,889	513,302	127,873
1078	372	Leased Property	S		-	-	-	-
1079	373	Street Lighting	S		2,400,244	632,204	2,757,903	699,721
1080				B3	247,708,906	68,895,803	303,235,403	78,514,380

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
1081								
1082	403GP	General Depreciation						
1083			S		12,364,577	3,788,995	7,490,201	2,146,608
1084			SG		-	-	-	-
1085			SG		-	-	-	-
1086			SE		100,598	26,983	95,658	25,658
1087			CN		4,814,596	1,451,107	6,972,479	2,101,488
1088			SG		7,488,999	2,078,615	2,703,736	750,437
1089			SO		40,455,878	11,290,787	68,077,147	18,999,577
1090			SG		-	-	-	-
1091			SG		-	-	-	-
1092				B3	65,224,647	18,636,487	85,339,221	24,023,768
1093								
1094	403GV0	General Vehicles						
1095			SG		-	-	-	-
1096				B3	-	-	-	-
1097								
1098	403MP	Mining Depreciation						
1099			SE		-	-	-	-
1100				B3	-	-	-	-
1101								
1102	403EP	Experimental Plant Depreciation						
1103			SG		-	-	-	-
1104			SG		-	-	-	-
1105				B3	-	-	-	-
1106	4031	ARO Depreciation						
1107			S		-	-	-	-
1108				B3	-	-	-	-
1109								
1110								
1111	**Total Depreciation Expense**			**B3**	**1,194,509,229**	**311,069,907**	**1,235,870,409**	**337,794,580**
1112								
1113	Summary	S			335,663,107	72,529,690	309,791,336	80,509,953
1114		DGP			-	-	-	-
1115		DGU			-	-	-	-
1116		SG			812,862,627	225,614,693	849,847,250	235,879,988
1117		SO			40,455,878	11,290,787	68,077,147	18,999,577
1118		CN			4,814,596	1,451,107	6,972,479	2,101,488
1119		SE			100,598	26,983	95,658	25,658
1120		SNPD			612,423	156,646	1,086,539	277,916
1121		SSGCT			-	-	-	-
1122	Total Depreciation Expense By Factor				1,194,509,229	311,069,907	1,235,870,409	337,794,580
1123								
1124	404GP	Amort of LT Plant - Leasehold Improvements						
1125			S		190,220	75,458	180,342	75,382
1126			SG		-	-	-	-
1127			SO		188,266	52,543	34,180	9,539
1128			SG		-	-	-	-
1129			CN		-	-	-	-
1130			SG		-	-	-	-
1131				B4	378,486	128,001	214,522	84,921
1132								
1133	404SP	Amort of LT Plant - Cap Lease Steam						
1134			SG		-	-	-	-
1135			SG		-	-	-	-
1136				B4	-	-	-	-
1137								
1138	404IP	Amort of LT Plant - Intangible Plant						
1139			S		173,284	8,929	160,301	8,838
1140			SE		986	265	-	-
1141			SG		8,898,775	2,469,906	5,500,965	1,526,824
1142			SO		20,134,706	5,619,373	-	-
1143			CN		6,104,294	1,839,819	-	-
1144			SG		2,697,714	748,766	2,682,975	744,675
1145			SG		264,285	73,354	255,549	70,929
1146			SG		-	-	-	-
1147			SG		-	-	-	-
1148			SG		-	-	-	-
1149			SG		-	-	-	-
1150				B4	38,274,045	10,760,412	8,599,790	2,351,266
1151								
1152	404MP	Amort of LT Plant - Mining Plant						
1153			SE		-	-	-	-
1154				B4	-	-	-	-
1155								
1156	404XP	Amort of LT Plant - Solar Plant						
1157			S		46,959	46,959	-	-
1158			SG		-	-	-	-
1159				B4	46,959	46,959	-	-
1160								
1161	404WP	Amort of LT Plant - Wind Plant						
1162			S		-	-	-	-

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
1163			SG		-	-	-	-
1164				B4	-	-	-	-
1165								
1166	404RP	Amort of LT Plant - Other Renewable Plant						
1167			S		-	-	-	-
1168			SG		-	-	-	-
1169				B4	-	-	-	-
1170								
1171	404OP	Amort of LT Plant - Other Plant						
1172			S		55,338	55,338	-	-
1173				B4	55,338	55,338	-	-
1174								
1175								
1176	404HP	Amortization of Other Electric Plant						
1177			SG		314,732	87,356	314,732	87,356
1178			SG		-	-	-	-
1179			SG		-	-	-	-
1180				B4	314,732	87,356	314,732	87,356
1181								
1182	**Total Amortization of Limited Term Plant**			**B4**	**39,069,560**	**11,078,066**	**9,129,044**	**2,523,544**
1183								
1184								
1185	405	Amortization of Other Electric Plant						
1186			S		-	-	-	-
1187								
1188				B4	-	-	-	-
1189								
1190	406	Amortization of Plant Acquisition Adj						
1191			S		301,635	-	301,635	-
1192			SG		-	-	-	-
1193			SG		-	-	-	-
1194			SG		75,351	20,914	75,351	20,914
1195			SO		-	-	-	-
1196				B4	376,987	20,914	376,987	20,914
1197	407	Amort of Prop Losses, Unrec Plant, etc						
1198			S		5,556,462	122,861	(1,371,579)	(6,805,180)
1199			SO		-	-	-	-
1200			SG-P		-	-	-	-
1201			SE		-	-	-	-
1202			SG		1,383,788	384,078	14,287,273	3,965,515
1203			TROJP		-	-	-	-
1204				B4	6,940,250	506,939	12,915,695	(2,839,665)
1205								
1206	**Total Amortization Expense**			**B4**	**46,386,797**	**11,605,919**	**22,421,726**	**(295,207)**
1207								
1208								
1209								
1210	Summary of Amortization Expense by Factor							
1211		S			6,323,898	309,545	(729,300)	(6,720,960)
1212		SE			986	265	-	-
1213		TROJP			-	-	-	-
1214		DGP			-	-	-	-
1215		DGU			-	-	-	-
1216		SO			20,322,972	5,671,916	34,180	9,539
1217		SSGCT			-	-	-	-
1218		SSGCH			-	-	-	-
1219		CN			6,104,294	1,839,819	-	-
1220		SG			13,634,646	3,784,374	23,116,846	6,416,213
1221	Total Amortization Expense by Factor				46,386,797	11,605,919	22,421,726	(295,207)
1222	408	Taxes Other Than Income						
1223			S		49,717,763	45,063,863	57,929,367	53,275,467
1224			GPS		152,360,699	42,553,672	185,102,997	51,698,451
1225			SO		22,024,729	6,146,858	22,024,729	6,146,858
1226			SE		1,159,659	311,053	1,159,659	311,053
1227			SG		4,984,631	1,383,513	5,224,557	1,450,106
1228			OPRV-ID		-	-	-	-
1229			EXCTAX		-	-	-	-
1230			SG		-	-	-	-
1231								
1232								
1233								
1234	**Total Taxes Other Than Income**			**B5**	**230,247,482**	**95,458,958**	**271,441,309**	**112,881,934**
1235								
1236								
1237	41140	Deferred Investment Tax Credit - Fed						
1238			DGU		(363,488)	-	(514)	-
1239								
1240				B7	(363,488)	-	(514)	-
1241								
1242	41141	Deferred Investment Tax Credit - Idaho						
1243			DGU		-	-	-	-
1244								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
1245				B7	-	-	-	-
1246								
1247	**Total Deferred ITC**			**B7**	**(363,488)**	**-**	**(514)**	**-**
1248								
1249								
1250	427	Interest on Long-Term Debt						
1251			S		625,555,617	178,575,329	647,000,245	178,098,945
1252			SNP		-	-	-	-
1253				B6	625,555,617	178,575,329	647,000,245	178,098,945
1254								
1255	428	Amortization of Debt Disc & Exp						
1256			SNP		7,525,246	1,998,446	7,525,246	1,998,446
1257				B6	7,525,246	1,998,446	7,525,246	1,998,446
1258								
1259	429	Amortization of Premium on Debt						
1260			SNP		-	-	-	-
1261				B6	-	-	-	-
1262								
1263	431	Other Interest Expense						
1264			OTH		-	-	-	-
1265			SO		-	-	-	-
1266			SNP		48,749,096	12,946,080	48,749,096	12,946,080
1267				B6	48,749,096	12,946,080	48,749,096	12,946,080
1268								
1269	432	AFUDC - Borrowed						
1270			SNP		(107,026,208)	(28,422,473)	(107,026,208)	(28,422,473)
1271					(107,026,208)	(28,422,473)	(107,026,208)	(28,422,473)
1272								
1273		Total Elec. Interest Deductions for T		B6	574,803,750	165,097,382	596,248,378	164,620,998
1274								
1275		Non-Regulated Portion of Interest						
1276			427 NUTIL		-	-	-	-
1277			428 NUTIL		-	-	-	-
1278			429 NUTIL		-	-	-	-
1279			431 NUTIL		-	-	-	-
1280								
1281		Total Non-Regulated Interest			-	-	-	-
1282								
1283		Total Interest Deductions for Tax		B6	574,803,750	165,097,382	596,248,378	164,620,998
1284								
1285								
1286	419	Interest & Dividends						
1287			S		-	-	-	-
1288			SNP		(161,070,065)	(42,774,659)	(10,642,278)	(2,826,222)
1289		Total Operating Deductions for Tax		B6	(161,070,065)	(42,774,659)	(10,642,278)	(2,826,222)
1290								
1291								
1292	41010	Deferred Income Tax - Federal-DR						
1293			S		(21,930,631)	166,609	(92,330,595)	(3,210,509)
1294			TROJD		-	-	-	-
1295			SG		-	-	-	-
1296			SO		97,967,891	27,341,752	(6,586,584)	(1,838,243)
1297			SNP		65,915,760	17,504,955	3,795,050	1,007,835
1298			SE		(149,795)	(40,179)	-	-
1299			SG		45,407,066	12,602,992	8,381,975	2,326,465
1300			GPS		25,323,177	7,072,652	4,198,068	1,172,502
1301			DITEXP		-	-	-	-
1302			BADDEBT		-	-	-	-
1303			CN		-	-	-	-
1304			IBT		-	-	-	-
1305			CIAC		-	-	-	-
1306			SCHMDEXP		-	-	-	-
1307			TAXDEPR		355,362,421	98,470,836	356,980,970	98,919,335
1308			SNPD		9,336	2,388	(1)	(0)
1309				B7	567,905,225	163,122,005	274,438,884	98,377,386
1310								
1311								
1312								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
1313	41110	Deferred Income Tax - Federal-CR						
1314			S		(62,243,303)	(13,135,842)	(67,838,101)	(6,989,069)
1315			SE		(1,832,284)	(491,470)	3,892,588	1,044,101
1316			SG		-	-	-	-
1317			SNP		(51,011,252)	(13,546,831)	(2,738,332)	(727,207)
1318			SG		(34,046,472)	(9,449,794)	2,957,649	820,913
1319			GPS		506,982	141,598	-	-
1320			SO		(2,250,320)	(628,039)	3,447,559	962,176
1321			SNPD		(920,236)	(235,379)	-	-
1322			BADDEBT		1,277,682	545,834	0	0
1323			SG		-	-	-	-
1324			SG		-	-	-	-
1325			TROJD		(58,006)	(16,003)	(9,103)	(2,511)
1326			CN		-	-	-	-
1327			CIAC		(44,753,800)	(11,447,167)	(9,287,598)	(2,375,590)
1328			SCHMDEXP		(292,180,384)	(79,608,159)	(301,263,024)	(82,082,837)
1329			TAXDEPR		-	-	-	-
1330				B7	(487,511,393)	(127,871,253)	(370,838,361)	(89,350,025)
1331								
1332	**Total Deferred Income Taxes**			**B7**	**80,393,832**	**35,250,752**	**(96,399,478)**	**9,027,360**
1333	SCHMAF	Additions - Flow Through						
1334			S		-	-	-	-
1335			SNP		-	-	-	-
1336			SO		-	-	-	-
1337			SE		-	-	-	-
1338			TROJP		-	-	-	-
1339			SG		-	-	-	-
1340				B6	-	-	-	-
1341								
1342	SCHMAP	Additions - Permanent						
1343			S		-	-	-	-
1344			SE		38,294	10,271	17,722	4,753
1345			SNP		-	-	-	-
1346			SO		1,666,251	465,032	2,228,878	622,055
1347			SG		-	-	-	-
1348			SCHMDEXP		142,812	38,911	134,376	36,612
1349				B6	1,847,356	514,214	2,380,975	663,421
1350								
1351	SCHMAT	Additions - Temporary						
1352			S		(28,667,399)	(7,505,114)	11,923,870	(13,389,750)
1353			SG		-	-	-	-
1354			CIAC		182,025,168	46,558,562	37,775,038	9,662,133
1355			SNP		207,475,831	55,098,432	11,137,499	2,957,736
1356			TROJD		235,928	65,090	37,028	10,216
1357			SG		-	-	-	-
1358			SE		7,452,375	1,998,935	(15,832,138)	(4,246,621)
1359			SG		1,612,426	447,538	12,102,484	3,359,114
1360			GPS		(2,062,025)	(575,914)	0	0
1361			SO		(1,376,599)	(384,194)	(11,127,808)	(3,105,648)
1362			SNPD		3,742,834	957,345	-	-
1363			BADDEBT		(5,196,660)	(2,220,046)	0	0
1364			CN		-	-	-	-
1365			SCHMDEXP		1,188,372,462	323,786,774	1,225,313,887	333,851,922
1366				B6	1,553,614,339	418,227,408	1,271,329,860	329,099,103
1367								
1368	TOTAL SCHEDULE - M ADDITIONS			B6	1,555,461,695	418,741,622	1,273,710,835	329,762,524
1369								
1370	SCHMDF	Deductions - Flow Through						
1371			S		-	-	-	-
1372			DGP		-	-	-	-
1373			DGU		-	-	-	-
1374				B6	-	-	-	-
1375	SCHMDP	Deductions - Permanent						
1376			S		-	-	-	-
1377			SE		3,623,779	971,998	5,620,656	1,507,617
1378			SNP		79,071	20,999	0	0
1379			SCHMDEXP		-	-	-	-
1380			SG		-	-	-	-
1381			SO		-	-	-	-
1382				B6	3,702,850	992,997	5,620,656	1,507,617
1383								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
1384	SCHMDT	Deductions - Temporary						
1385			S		(89,197,459)	677,644	(375,532,146)	(13,057,961)
1386			BADDEBT		-	-	-	-
1387			SNP		268,096,276	71,197,133	15,435,437	4,099,120
1388			CN		-	-	-	-
1389			SG		-	-	-	-
1390			DGP		-	-	-	-
1391			SE		(609,257)	(163,420)	(0)	(0)
1392			SG		184,682,178	51,259,600	34,091,648	9,462,333
1393			GPS		102,995,844	28,766,285	17,074,616	4,768,865
1394			SO		398,460,507	111,205,911	(26,789,325)	(7,476,604)
1395			TAXDEPR		1,445,349,992	400,506,113	1,451,933,046	402,330,276
1396			SNPD		37,979	9,714	0	0
1397				B6	2,309,816,061	663,458,981	1,116,213,277	400,126,029
1398								
1399	TOTAL SCHEDULE - M DEDUCTIONS			B6	2,313,518,911	664,451,978	1,121,833,933	401,633,646
1400								
1401	**TOTAL SCHEDULE - M ADJUSTMENTS**			**B6**	**(758,057,216)**	**(245,710,356)**	**151,876,902**	**(71,871,122)**
1402								
1403								
1404								
1405	40911	State Income Taxes						
1406					(10,561,442)	(3,358,031)	112,048,550	4,648,805
1407			S		17,136,960	8,399,814	9,229,930	492,784
1408		PTC	SG		-	-	-	-
1409			IBT		-	-	-	-
1410	**Total State Tax Expense**				**6,575,518**	**5,041,783**	**121,278,480**	**5,141,589**
1411								
1412								
1413	Calculation of Taxable Income:							
1414		Operating Revenues			7,127,285,895	1,930,056,563	7,019,076,002	1,921,396,720
1415		Operating Deductions:						
1416		O & M Expenses			4,722,579,629	1,219,238,893	2,588,595,571	1,135,057,645
1417		Depreciation Expense			1,194,509,229	311,069,907	1,235,870,409	337,794,580
1418		Amortization Expense			46,386,797	11,605,919	22,421,726	(295,207)
1419		Taxes Other Than Income			230,247,482	95,458,958	271,441,309	112,881,934
1420		Interest & Dividends (AFUDC-Equity)			(161,070,065)	(42,774,659)	(10,642,278)	(2,826,222)
1421		Misc Revenue & Expense			(5,597,257)	(1,384,747)	(1,011,940)	(104,716)
1422		Total Operating Deductions			6,027,055,814	1,593,214,271	4,106,674,797	1,582,508,013
1423		Other Deductions:						
1424		Interest Deductions			574,803,750	165,097,382	596,248,378	164,620,998
1425		Interest on PCRBS			-	-	-	-
1426		Schedule M Adjustments			(758,057,216)	(245,710,356)	151,876,902	(71,871,122)
1427								
1428		Income Before State Taxes			(232,630,885)	(73,965,445)	2,468,029,728	102,396,587
1429								
1430		State Income Taxes			6,575,518	5,041,783	121,278,480	5,141,589
1431								
1432	Total Taxable Income				(239,206,403)	(79,007,229)	2,346,751,248	97,254,998
1433								
1434	Tax Rate				21.0%	21.0%	21.0%	21.0%
1435								
1436	Federal Income Tax - Calculated				(50,233,345)	(16,591,518)	492,817,762	20,423,550
1437								
1438	Adjustments to Calculated Tax:							
1439	40910		SE		(32,172)	(8,629)	(13,813)	(3,705)
1440	40910	PTC	SG		(228,945,221)	(63,545,062)	0	0
1441	40910		SO		(53,814)	(15,019)	(55,263)	(15,423)
1442	40910	PTC	S		-	-	(81,033,112)	(81,033,112)
1443	**Federal Income Tax Expense**				**(279,264,551)**	**(80,160,228)**	**411,715,574**	**(60,628,691)**
1444								
1445	**Total Operating Expenses**				**5,995,467,190**	**1,596,121,237**	**4,553,911,138**	**1,538,874,495**
1446	310	Land and Land Rights						
1447			SG		-	-	-	-
1448			SG		-	-	-	-
1449			SG		50,518,330	14,021,653	50,518,330	14,021,653
1450			S		-	-	-	-
1451			SG		-	-	-	-
1452				B8	50,518,330	14,021,653	50,518,330	14,021,653
1453								
1454	311	Structures and Improvements						
1455			SG		-	-	-	-
1456			SG		-	-	-	-
1457			SG		1,049,095,490	291,182,482	1,049,095,490	291,182,482
1458			SG		-	-	-	-
1459				B8	1,049,095,490	291,182,482	1,049,095,490	291,182,482
1460								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
1461	312	Boiler Plant Equipment						
1462			SG		-	-	-	-
1463			SG		-	-	-	-
1464			SG		4,407,779,222	1,223,404,453	4,432,182,022	1,230,177,591
1465			SG		-	-	-	-
1466				B8	4,407,779,222	1,223,404,453	4,432,182,022	1,230,177,591
1467								
1468	314	Turbogenerator Units						
1469			SG		-	-	-	-
1470			SG		-	-	-	-
1471			SG		965,486,229	267,976,251	965,486,229	267,976,251
1472			SG		-	-	-	-
1473				B8	965,486,229	267,976,251	965,486,229	267,976,251
1474								
1475	315	Accessory Electric Equipment						
1476			SG		-	-	-	-
1477			SG		-	-	-	-
1478			SG		441,152,287	122,444,352	441,152,287	122,444,352
1479			SG		-	-	-	-
1480				B8	441,152,287	122,444,352	441,152,287	122,444,352
1481								
1482								
1483								
1484	316	Misc Power Plant Equipment						
1485			SG		-	-	-	-
1486			SG		-	-	-	-
1487			SG		32,916,409	9,136,138	32,916,409	9,136,138
1488			SG		-	-	-	-
1489				B8	32,916,409	9,136,138	32,916,409	9,136,138
1490								
1491	317	Steam Plant ARO						
1492			S		-	-	-	-
1493				B8	-	-	-	-
1494								
1495	SP	Unclassified Steam Plant - Account 300						
1496			SG		176,015,597	48,854,140	176,015,597	48,854,140
1497				B8	176,015,597	48,854,140	176,015,597	48,854,140
1498								
1499								
1500	**Total Steam Production Plant**			**B8**	**7,122,963,563**	**1,977,019,471**	**7,147,366,363**	**1,983,792,608**
1501								
1502								
1503	Summary of Steam Production Plant by Factor							
1504		S			-	-	-	-
1505		DGP			-	-	-	-
1506		DGU			-	-	-	-
1507		SG			7,122,963,563	1,977,019,471	7,147,366,363	1,983,792,608
1508		SSGCH			-	-	-	-
1509	Total Steam Production Plant by Factor				7,122,963,563	1,977,019,471	7,147,366,363	1,983,792,608
1510	320	Land and Land Rights						
1511			SG		-	-	-	-
1512			SG		-	-	-	-
1513				B8	-	-	-	-
1514								
1515	321	Structures and Improvements						
1516			SG		-	-	-	-
1517			SG	B8	-	-	-	-
1518					-	-	-	-
1519								
1520	322	Reactor Plant Equipment						
1521			SG		-	-	-	-
1522			SG		-	-	-	-
1523				B8	-	-	-	-
1524								
1525	323	Turbogenerator Units						
1526			SG		-	-	-	-
1527			SG		-	-	-	-
1528				B8	-	-	-	-
1529								
1530	324	Land and Land Rights						
1531			SG		-	-	-	-
1532			SG		-	-	-	-
1533				B8	-	-	-	-
1534								
1535	325	Misc. Power Plant Equipment						
1536			SG		-	-	-	-
1537			SG		-	-	-	-
1538				B8	-	-	-	-
1539								
1540								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
1541	NP	Unclassified Nuclear Plant - Acct 300						
1542			SG		-	-	-	-
1543				B8	-	-	-	-
1544								
1545								
1546	**Total Nuclear Production Plant**			**B8**	**-**	**-**	**-**	**-**
1547								
1548								
1549								
1550	Summary of Nuclear Production Plant by Factor							
1551		DGP			-	-	-	-
1552		DGU			-	-	-	-
1553		SG			-	-	-	-
1554		SG-P			-	-	-	-
1555	Total Nuclear Plant by Factor				-	-	-	-
1556								
1557	330	Land and Land Rights						
1558			SG		-	-	-	-
1559			SG		-	-	-	-
1560			SG		30,913,012	8,580,084	30,913,012	8,580,084
1561			SG		6,598,315	1,831,400	6,598,315	1,831,400
1562				B8	37,511,327	10,411,484	37,511,327	10,411,484
1563								
1564	331	Structures and Improvements						
1565			SG		-	-	-	-
1566			SG		-	-	-	-
1567			SG		301,728,202	83,746,396	301,728,202	83,746,396
1568			SG		23,286,122	6,463,197	23,286,122	6,463,197
1569				B8	325,014,324	90,209,593	325,014,324	90,209,593
1570								
1571	332	Reservoirs, Dams & Waterways						
1572			SG		-	-	-	-
1573			SG		-	-	-	-
1574			SG		424,848,504	117,919,144	569,002,622	157,929,948
1575			SG		107,957,568	29,964,243	144,760,734	40,179,174
1576			SG		-	-	(1,000,472)	(277,687)
1577				B8	532,806,072	147,883,387	712,762,883	197,831,434
1578								
1579	333	Water Wheel, Turbines, & Generators						
1580			SG		-	-	-	-
1581			SG		-	-	-	-
1582			SG		81,146,050	22,522,553	81,146,050	22,522,553
1583			SG		51,284,522	14,234,314	51,284,522	14,234,314
1584				B8	132,430,572	36,756,866	132,430,572	36,756,866
1585								
1586	334	Accessory Electric Equipment						
1587			SG		-	-	-	-
1588			SG		-	-	-	-
1589			SG		13,047,000	3,621,270	13,047,000	3,621,270
1590			SG		58,178,441	16,147,761	58,178,441	16,147,761
1591			SG		14,716,774	4,084,725	14,716,774	4,084,725
1592				B8	85,942,215	23,853,756	85,942,215	23,853,756
1593								
1594								
1595								
1596	335	Misc. Power Plant Equipment						
1597			SG		-	-	-	-
1598			SG		-	-	-	-
1599			SG		3,230,593	896,670	3,230,593	896,670
1600			SG		219,614	60,955	219,614	60,955
1601				B8	3,450,207	957,625	3,450,207	957,625
1602								
1603	336	Roads, Railroads & Bridges						
1604			SG		-	-	-	-
1605			SG		-	-	-	-
1606			SG		23,403,109	6,495,667	23,403,109	6,495,667
1607			SG		4,492,225	1,246,843	4,492,225	1,246,843
1608				B8	27,895,334	7,742,510	27,895,334	7,742,510
1609								
1610	337	Hydro Plant ARO						
1611			S		-	-	-	-
1612				B8	-	-	-	-
1613								
1614	HP	Unclassified Hydro Plant - Acct 300						
1615			S		-	-	-	-
1616			SG		-	-	-	-
1617			SG		-	-	-	-
1618			SG		-	-	-	-
1619				B8	-	-	-	-
1620								
1621	**Total Hydraulic Production Plant**			**B8**	**1,145,050,050**	**317,815,222**	**1,325,006,862**	**367,763,269**
1622								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
1623	Summary of Hydraulic Plant by Factor							
1624		S			-	-	-	-
1625		SG			1,145,050,050	317,815,222	1,325,006,862	367,763,269
1626		DGP			-	-	-	-
1627		DGU			-	-	-	-
1628	Total Hydraulic Plant by Factor				1,145,050,050	317,815,222	1,325,006,862	367,763,269
1629								
1630	338XP	Solar Plant						
1631			S		1,331,496	770,480	1,477,691	919,203
1632			SG		56,322	15,632	56,322	15,632
1633				B8	1,387,818	786,112	1,534,013	934,836
1634								
1635								
1636	**Total Solar Plant**			**B8**	**1,387,818**	**786,112**	**1,534,013**	**934,836**
1637								
1638	Summary of Solar Plant by Factor							
1639		S			1,331,496	770,480	1,477,691	919,203
1640		SG			56,322	15,632	56,322	15,632
1641	Total Solar Plant by Factor				1,387,818	786,112	1,534,013	934,836
1642								
1643	338WP	Wind Plant						
1644			S		-	-	-	-
1645			SG		4,002,239,279	1,110,844,512	4,750,040,478	1,318,401,032
1646				B8	4,002,239,279	1,110,844,512	4,750,040,478	1,318,401,032
1647								
1648								
1649	**Total Wind Plant**			**B8**	**4,002,239,279**	**1,110,844,512**	**4,750,040,478**	**1,318,401,032**
1650								
1651	Summary of Wind Plant by Factor							
1652		S			-	-	-	-
1653		SG			4,002,239,279	1,110,844,512	4,750,040,478	1,318,401,032
1654	Total Wind Plant by Factor				4,002,239,279	1,110,844,512	4,750,040,478	1,318,401,032
1655								
1656	339	Other Renewable Plant						
1657			S		-	-	-	-
1658			SG		157,826,749	43,805,721	159,468,649	44,261,440
1659				B8	157,826,749	43,805,721	159,468,649	44,261,440
1660								
1661	**Total Other Renewable Plant**			**B8**	**157,826,749**	**43,805,721**	**159,468,649**	**44,261,440**
1662								
1663	Summary of Other Renewable Plant by Factor							
1664		S			-	-	-	-
1665		SG			157,826,749	43,805,721	159,468,649	44,261,440
1666	Total Other Renewable Plant by Factor				157,826,749	43,805,721	159,468,649	44,261,440
1667								
1668	340	Land and Land Rights						
1669			S		-	-	-	-
1670			SG		39,257,634	10,896,182	39,257,634	10,896,182
1671			SG		-	-	-	-
1672			SG		-	-	-	-
1673				B8	39,257,634	10,896,182	39,257,634	10,896,182
1674								
1675	341	Structures and Improvements						
1676			S		-	-	-	-
1677			SG		175,538,274	48,721,657	175,538,274	48,721,657
1678			SG		-	-	-	-
1679			SG		-	-	-	-
1680			SG		-	-	-	-
1681				B8	175,538,274	48,721,657	175,538,274	48,721,657
1682								
1683	342	Fuel Holders, Producers & Accessories						
1684			SG		16,439,353	4,562,837	16,439,353	4,562,837
1685			SG		-	-	-	-
1686			SG		-	-	-	-
1687				B8	16,439,353	4,562,837	16,439,353	4,562,837

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
1688								
1689	343	Prime Movers						
1690			S		-	-	-	-
1691			SG		-	-	-	-
1692			SG		-	-	-	-
1693			SG		1,165,620,094	323,524,556	1,221,185,188	338,946,967
1694			SG		-	-	-	-
1695				B8	1,165,620,094	323,524,556	1,221,185,188	338,946,967
1696								
1697	344	Generators						
1698			S		-	-	-	-
1699			SG		-	-	-	-
1700			SG		435,567,770	120,894,338	435,567,770	120,894,338
1701			SG		-	-	-	-
1702				B8	435,567,770	120,894,338	435,567,770	120,894,338
1703								
1704	345	Accessory Electric Plant						
1705			S		-	-	-	-
1706			SG		217,908,917	60,481,872	217,908,917	60,481,872
1707			SG		-	-	-	-
1708			SG		-	-	-	-
1709			SG		-	-	-	-
1710				B8	217,908,917	60,481,872	217,908,917	60,481,872
1711								
1712								
1713								
1714	346	Misc. Power Plant Equipment						
1715			SG		12,977,877	3,602,084	12,977,877	3,602,084
1716			SG		-	-	-	-
1717			SG		-	-	-	-
1718				B8	12,977,877	3,602,084	12,977,877	3,602,084
1719								
1720	347	Other Production ARO						
1721			S		-	-	-	-
1722				B8	-	-	-	-
1723								
1724	OP	Unclassified Other Prod Plant-Acct 300						
1725			S		-	-	-	-
1726			SG		-	-	-	-
1727					-	-	-	-
1728								
1729	**Total Other Production Plant**			**B8**	**2,063,309,919**	**572,683,525**	**2,118,875,013**	**588,105,936**
1730								
1731	Summary of Other Production Plant by Factor							
1732		S			-	-	-	-
1733		DGU			-	-	-	-
1734		SG			2,063,309,919	572,683,525	2,118,875,013	588,105,936
1735		SSGCT			-	-	-	-
1736	Total of Other Production Plant by Factor				2,063,309,919	572,683,525	2,118,875,013	588,105,936
1737								
1738	Experimental Plant							
1739	103	Experimental Plant						
1740			SG		-	-	-	-
1741	**Total Experimental Production Plant**			**B8**	**-**	**-**	**-**	**-**
1742								
1743	**Total Production Plant**			**B8**	**14,492,777,378**	**4,022,954,563**	**15,502,291,377**	**4,303,259,121**
1744	350	Land and Land Rights						
1745			SG		-	-	-	-
1746			SG		-	-	-	-
1747			SG		439,915,244	122,101,004	439,915,244	122,101,004
1748				B8	439,915,244	122,101,004	439,915,244	122,101,004
1749								
1750	351	Energy Storage						
1751			S		-	-	-	-
1752			SG		292,593,500	81,211,007	292,593,500	81,211,007
1753					292,593,500	81,211,007	292,593,500	81,211,007
1754								
1755	352	Structures and Improvements						
1756			S		-	-	-	-
1757			SG		-	-	-	-
1758			SG		-	-	-	-
1759			SG		475,456,182	131,965,596	475,225,563	131,901,586
1760				B8	475,456,182	131,965,596	475,225,563	131,901,586
1761								
1762	353	Station Equipment						
1763			SG		-	-	-	-
1764			SG		-	-	-	-
1765			SG		2,999,976,065	832,660,597	2,995,470,086	831,409,936
1766				B8	2,999,976,065	832,660,597	2,995,470,086	831,409,936
1767								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
1768	354	Towers and Fixtures						
1769			SG		-	-	-	-
1770			SG		-	-	-	-
1771			SG		2,589,458,008	718,718,951	2,589,458,008	718,718,951
1772				B8	2,589,458,008	718,718,951	2,589,458,008	718,718,951
1773								
1774	355	Poles and Fixtures						
1775			S		-	-	0	0
1776			SG		-	-	-	-
1777			SG		1,559,870,627	432,951,057	2,433,431,177	675,412,807
1778				B8	1,559,870,627	432,951,057	2,433,431,177	675,412,807
1779								
1780	356	Clearing and Grading						
1781			SG		-	-	-	-
1782			SG		-	-	-	-
1783			SG		2,376,247,353	659,541,109	2,376,247,353	659,541,109
1784				B8	2,376,247,353	659,541,109	2,376,247,353	659,541,109
1785								
1786	357	Underground Conduit						
1787			SG		-	-	-	-
1788			SG		-	-	-	-
1789			SG		3,924,286	1,089,208	3,924,286	1,089,208
1790				B8	3,924,286	1,089,208	3,924,286	1,089,208
1791								
1792	358	Underground Conductors						
1793			SG		-	-	-	-
1794			SG		-	-	-	-
1795			SG		9,083,639	2,521,216	9,083,639	2,521,216
1796				B8	9,083,639	2,521,216	9,083,639	2,521,216
1797								
1798	359	Roads and Trails						
1799			SG		-	-	-	-
1800			SG		-	-	-	-
1801			SG		12,141,468	3,369,934	12,141,468	3,369,934
1802				B8	12,141,468	3,369,934	12,141,468	3,369,934
1803								
1804	TP	Unclassified Trans Plant - Acct 300						
1805			SG		691,399,059	191,901,782	691,399,059	191,901,782
1806				B8	691,399,059	191,901,782	691,399,059	191,901,782
1807								
1808	TS0	Unclassified Trans Sub Plant - Acct 300						
1809			SG		-	-	-	-
1810				B8	-	-	-	-
1811								
1812	**Total Transmission Plant**			**B8**	**11,450,065,431**	**3,178,031,461**	**12,318,889,382**	**3,419,178,541**
1813	Summary of Transmission Plant by Factor							
1814		DGP			-	-	-	-
1815		DGU			-	-	-	-
1816		SG			11,450,065,431	3,178,031,461	12,318,889,382	3,419,178,541
1817	Total Transmission Plant by Factor				11,450,065,431	3,178,031,461	12,318,889,382	3,419,178,541
1818	360	Land and Land Rights						
1819			S		83,614,703	16,649,324	96,593,548	18,539,263
1820				B8	83,614,703	16,649,324	96,593,548	18,539,263
1821								
1822	361	Structures and Improvements						
1823			S		159,347,721	39,449,050	183,962,000	42,930,779
1824				B8	159,347,721	39,449,050	183,962,000	42,930,779
1825								
1826	362	Station Equipment						
1827			S		1,324,448,169	326,646,954	1,530,031,721	356,583,387
1828				B8	1,324,448,169	326,646,954	1,530,031,721	356,583,387
1829								
1830	363	Storage Battery Equipment						
1831			S		167,516,883	63,067,556	200,760,284	67,908,356
1832			CN		10,802,634	3,255,887	10,802,634	3,255,887
1833			SNPD		35,847,239	9,169,039	37,730,467	9,650,733
1834				B8	214,166,756	75,492,482	249,293,386	80,814,976
1835								
1836	364	Poles, Towers & Fixtures						
1837			S		1,886,752,055	652,713,426	2,179,617,565	695,359,584
1838				B8	1,886,752,055	652,713,426	2,179,617,565	695,359,584
1839								
1840	365	Overhead Conductors						
1841			S		1,212,214,100	422,910,335	1,400,376,450	450,309,947
1842				B8	1,212,214,100	422,910,335	1,400,376,450	450,309,947
1843								
1844	366	Underground Conduit						
1845			S		562,696,704	134,110,659	650,039,637	146,829,263
1846				B8	562,696,704	134,110,659	650,039,637	146,829,263
1847								
1848								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
1849								
1850								
1851	367	Underground Conductors						
1852			S		1,295,564,397	255,830,480	1,496,664,550	285,114,054
1853				B8	1,295,564,397	255,830,480	1,496,664,550	285,114,054
1854								
1855	368	Line Transformers						
1856			S		1,781,234,132	570,186,837	2,057,720,934	610,447,978
1857				B8	1,781,234,132	570,186,837	2,057,720,934	610,447,978
1858								
1859	369	Services						
1860			S		1,144,422,539	393,973,651	1,322,062,144	419,840,973
1861				B8	1,144,422,539	393,973,651	1,322,062,144	419,840,973
1862								
1863	370	Meters						
1864			S		328,600,867	111,652,839	379,606,965	119,080,187
1865				B8	328,600,867	111,652,839	379,606,965	119,080,187
1866								
1867	371	Installations on Customers' Premises						
1868			S		9,045,516	2,755,753	10,449,580	2,960,208
1869				B8	9,045,516	2,755,753	10,449,580	2,960,208
1870								
1871	372	Leased Property						
1872			S		-	-	-	-
1873				B8	-	-	-	-
1874								
1875	373	Street Lights						
1876			S		67,979,442	25,386,390	78,531,350	26,922,926
1877				B8	67,979,442	25,386,390	78,531,350	26,922,926
1878								
1879	DP	Unclassified Dist Plant - Acct 300						
1880			S		317,938,278	122,182,731	317,938,278	122,182,731
1881				B8	317,938,278	122,182,731	317,938,278	122,182,731
1882								
1883	DS0	Unclassified Dist Sub Plant - Acct 300						
1884			S		-	-	-	-
1885				B8	-	-	-	-
1886								
1887								
1888	**Total Distribution Plant**			**B8**	**10,388,025,380**	**3,149,940,913**	**11,952,888,109**	**3,377,916,256**
1889								
1890	Summary of Distribution Plant by Factor							
1891			S		10,341,375,507	3,137,515,987	11,904,355,007	3,365,009,636
1892			CN		10,802,634	3,255,887	10,802,634	3,255,887
1893			SNPD		35,847,239	9,169,039	37,730,467	9,650,733
1894								
1895	Total Distribution Plant by Factor				10,388,025,380	3,149,940,913	11,952,888,109	3,377,916,256
1896	389	Land and Land Rights						
1897			S		19,106,578	9,084,974	19,106,578	9,084,974
1898			CN		1,128,506	340,129	1,128,506	340,129
1899			SG		-	-	-	-
1900			SG		1,560	433	1,560	433
1901			SO		7,611,617	2,124,318	7,611,617	2,124,318
1902				B8	27,848,261	11,549,854	27,848,261	11,549,854
1903								
1904	390	Structures and Improvements						
1905			S		151,673,623	44,496,575	151,673,623	44,496,575
1906			SG		-	-	-	-
1907			SG		-	-	-	-
1908			CN		8,218,829	2,477,134	8,218,829	2,477,134
1909			SG		12,023,520	3,337,197	12,023,520	3,337,197
1910			SE		940,953	252,390	940,953	252,390
1911			SO		117,070,442	32,673,063	117,070,442	32,673,063
1912				B8	289,927,366	83,236,359	289,927,366	83,236,359
1913								
1914	391	Office Furniture & Equipment						
1915			S		2,786,446	1,045,284	2,786,446	1,045,284
1916			SG		-	-	-	-
1917			SG		-	-	-	-
1918			CN		307,766	92,760	307,766	92,760
1919			SG		1,999,273	554,910	1,999,273	554,910
1920			SE		3,822	1,025	3,822	1,025
1921			SO		16,378,196	4,570,973	16,378,196	4,570,973
1922			SG		-	-	-	-
1923			SG		-	-	-	-
1924				B8	21,475,503	6,264,952	21,475,503	6,264,952

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
1925								
1926	392	Transportation Equipment						
1927			S		112,148,624	27,547,977	112,148,624	27,547,977
1928			SO		6,322,053	1,764,415	6,322,053	1,764,415
1929			SG		24,622,473	6,834,109	24,622,473	6,834,109
1930			CN		-	-	-	-
1931			SG		-	-	-	-
1932			SE		159,837	42,873	159,837	42,873
1933			SG		-	-	-	-
1934			SG		-	-	-	-
1935			SG		-	-	-	-
1936				B8	143,252,987	36,189,374	143,252,987	36,189,374
1937								
1938	393	Stores Equipment						
1939			S		11,913,385	3,974,550	11,913,385	3,974,550
1940			SG		-	-	-	-
1941			SG		-	-	-	-
1942			SO		283,479	79,116	283,479	79,116
1943			SG		7,815,837	2,169,330	7,815,837	2,169,330
1944			SG		-	-	-	-
1945				B8	20,012,702	6,222,996	20,012,702	6,222,996
1946								
1947	394	Tools, Shop & Garage Equipment						
1948			S		37,339,318	10,470,028	37,339,318	10,470,028
1949			SG		-	-	-	-
1950			SG		22,430,751	6,225,784	22,430,751	6,225,784
1951			SO		1,603,787	447,599	1,603,787	447,599
1952			SE		125,691	33,714	125,691	33,714
1953			SG		-	-	-	-
1954			SG		-	-	-	-
1955			SG		-	-	-	-
1956				B8	61,499,547	17,177,125	61,499,547	17,177,125
1957								
1958	395	Laboratory Equipment						
1959			S		27,574,505	10,534,808	27,574,505	10,534,808
1960			SG		-	-	-	-
1961			SG		-	-	-	-
1962			SO		4,436,256	1,238,110	4,436,256	1,238,110
1963			SE		1,225,288	328,656	1,225,288	328,656
1964			SG		5,904,754	1,638,898	5,904,754	1,638,898
1965			SG		-	-	-	-
1966			SG		-	-	-	-
1967				B8	39,140,803	13,740,472	39,140,803	13,740,472
1968								
1969	396	Power Operated Equipment						
1970			S		176,107,144	49,430,917	176,107,144	49,430,917
1971			SG		-	-	-	-
1972			SG		32,063,214	8,899,329	32,063,214	8,899,329
1973			SO		5,683,753	1,586,273	5,683,753	1,586,273
1974			SG		-	-	-	-
1975			SE		74,794	20,062	74,794	20,062
1976			SG		-	-	-	-
1977			SG		-	-	-	-
1978				B8	213,928,905	59,936,580	213,928,905	59,936,580
1979	397	Communication Equipment						
1980			S		11,820,895	3,781,784	20,590,122	(2,706,709)
1981			SG		-	-	-	-
1982			SG		-	-	-	-
1983			SO		598,210,109	166,953,810	619,584,453	172,919,153
1984			CN		228,947,935	69,004,331	227,354,102	68,523,954
1985			SG		12,122,071	3,364,551	(7,338,285)	(2,036,783)
1986			SE		278,927	74,816	10,433	2,798
1987			SG		-	-	-	-
1988			SG		-	-	-	-
1989				B8	851,379,938	243,179,291	860,200,825	236,702,412
1990								
1991	398	Misc. Equipment						
1992			S		3,788,640	1,379,092	3,788,640	1,379,092
1993			SG		-	-	-	-
1994			SG		-	-	-	-
1995			CN		80,053	24,128	80,053	24,128
1996			SO		3,657,984	1,020,903	3,657,984	1,020,903
1997			SE		3,966	1,064	3,966	1,064
1998			SG		2,944,157	817,168	2,944,157	817,168
1999			SG		-	-	-	-
2000				B8	10,474,800	3,242,354	10,474,800	3,242,354

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
2001								
2002	399	Coal Mine						
2003			SE		1,822,901	488,953	39,748,016	10,661,525
2004	MP		SE		-	-	-	-
2005				B8	1,822,901	488,953	39,748,016	10,661,525
2006								
2007	399L	WIDCO Capital Lease						
2008			SE		-	-	-	-
2009					-	-	-	-
2010								
2011		Remove Capital Leases			-	-	-	-
2012					-	-	-	-
2013								
2014	1011390	General Capital Leases						
2015			S		22,285,718	7,816,249	22,285,718	7,816,249
2016			SG		6,235,401	1,730,671	6,235,401	1,730,671
2017			SO		-	-	-	-
2018				B9	28,521,120	9,546,920	28,521,120	9,546,920
2019								
2020		Remove Capital Leases			(28,521,120)	(9,546,920)	(28,521,120)	(9,546,920)
2021					-	-	-	-
2022								
2023	1011346	General Gas Line Capital Leases						
2024			SG		-	-	-	-
2025				B9	-	-	-	-
2026								
2027		Remove Capital Leases			-	-	-	-
2028					-	-	-	-
2029								
2030	GP	Unclassified Gen Plant - Acct 300						
2031			S		-	-	-	-
2032			SO		198,333,670	55,352,729	198,333,670	55,352,729
2033			CN		-	-	-	-
2034			SG		-	-	-	-
2035			SG		-	-	-	-
2036			SG		-	-	-	-
2037				B8	198,333,670	55,352,729	198,333,670	55,352,729
2038								
2039	399G	Unclassified Gen Plant - Acct 300						
2040			S		-	-	-	-
2041			SO		-	-	-	-
2042			SG		-	-	-	-
2043			SG		-	-	-	-
2044			SG		-	-	-	-
2045				B8	-	-	-	-
2046								
2047	**Total General Plant**			**B8**	**1,879,097,382**	**536,581,039**	**1,925,843,384**	**540,276,733**
2048								
2049	Summary of General Plant by Factor							
2050		S			576,544,878	169,562,237	585,314,105	163,073,744
2051		DGP			-	-	-	-
2052		DGU			-	-	-	-
2053		SG			128,163,011	35,572,380	108,702,655	30,171,047
2054		SO			959,591,346	267,811,308	980,965,690	273,776,650
2055		SE			4,636,178	1,243,552	42,292,799	11,344,107
2056		CN			238,683,088	71,938,482	237,089,255	71,458,104
2057		DEU			-	-	-	-
2058		SSGCT			-	-	-	-
2059		SSGCH			-	-	-	-
2060		Less Capital Leases			(28,521,120)	(9,546,920)	(28,521,120)	(9,546,920)
2061	Total General Plant by Factor				1,879,097,382	536,581,039	1,925,843,384	540,276,733
2062	301	Organization						
2063			S		-	-	-	-
2064			SO		-	-	-	-
2065			SG		-	-	-	-
2066				B8	-	-	-	-
2067	302	Franchise & Consent						
2068			S		1,000,000	-	1,000,000	-
2069			SG		24,555,063	6,815,399	24,512,823	6,803,675
2070			SG		103,455,075	28,714,551	103,455,075	28,714,551
2071			SG		10,501,813	2,914,839	10,195,370	2,829,784
2072			SG		-	-	-	-
2073			SG		-	-	-	-
2074				B8	139,511,951	38,444,788	139,163,268	38,348,009

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
2075								
2076	303	Miscellaneous Intangible Plant						
2077			S		23,164,744	4,601,718	23,001,523	4,597,089
2078			SG		178,129,067	49,440,746	171,644,833	47,641,010
2079			SO		-	-	(13,908,637)	(3,881,746)
2080			SE		-	-	-	-
2081			CN		-	-	(3,178,870)	(958,104)
2082			SG		-	-	-	-
2083			SG		-	-	-	-
2084				B8	201,293,811	54,042,464	177,558,849	47,398,249
2085	303	Less Non-Regulated Plant						
2086			S		-	-	-	-
2087					201,293,811	54,042,464	177,558,849	47,398,249
2088	IP	Unclassified Intangible Plant - Acct 300						
2089			S		-	-	-	-
2090			SG		-	-	-	-
2091			SG		-	-	-	-
2092			SO		-	-	-	-
2093					-	-	-	-
2094								
2095	**Total Intangible Plant**			**B8**	**340,805,762**	**92,487,252**	**316,722,118**	**85,746,258**
2096								
2097	Summary of Intangible Plant by Factor							
2098			S		24,164,744	4,601,718	24,001,523	4,597,089
2099			DGP		-	-	-	-
2100			DGU		-	-	-	-
2101			SG		316,641,017	87,885,534	309,808,102	85,989,019
2102			SO		-	-	(13,908,637)	(3,881,746)
2103			CN		-	-	(3,178,870)	(958,104)
2104			SSGCT		-	-	-	-
2105			SSGCH		-	-	-	-
2106			SE		-	-	-	-
2107	Total Intangible Plant by Factor				340,805,762	92,487,252	316,722,118	85,746,258
2108	Summary of Unclassified Plant (Account 106)							
2109			DP		317,938,278	122,182,731	317,938,278	122,182,731
2110			DS0		-	-	-	-
2111			GP		198,333,670	55,352,729	198,333,670	55,352,729
2112			HP		-	-	-	-
2113			NP		-	-	-	-
2114			OP		-	-	-	-
2115			TP		691,399,059	191,901,782	691,399,059	191,901,782
2116			TS0		-	-	-	-
2117			IP		-	-	-	-
2118			MP		-	-	-	-
2119			SP		176,015,597	48,854,140	176,015,597	48,854,140
2120	Total Unclassified Plant by Factor				1,383,686,604	418,291,382	1,383,686,604	418,291,382
2121								
2122	**Total Electric Plant In Service**			**B8**	**38,550,771,333**	**10,979,995,227**	**42,016,634,369**	**11,726,376,909**
2123	Summary of Electric Plant by Factor							
2124			S		10,943,416,625	3,312,450,422	12,515,148,326	3,533,599,673
2125			SE		4,636,178	1,243,552	42,292,799	11,344,107
2126			DGU		-	-	-	-
2127			DGP		-	-	-	-
2128			SG		26,386,315,341	7,323,673,458	28,238,213,825	7,837,678,525
2129			SO		959,591,346	267,811,308	967,057,053	269,894,904
2130			CN		249,485,723	75,194,368	244,713,019	73,755,887
2131			DEU		-	-	-	-
2132			SNPD		35,847,239	9,169,039	37,730,467	9,650,733
2133			SSGCT		-	-	-	-
2134			Less Capital Leases		(28,521,120)	(9,546,920)	(28,521,120)	(9,546,920)
2135					38,550,771,333	10,979,995,227	42,016,634,369	11,726,376,909
2136	105	Plant Held For Future Use						
2137			S		9,731,278	4,562,424	-	-
2138			SG		-	-	-	-
2139			SG		-	-	-	-
2140			SG		-	-	-	-
2141			SE		-	-	-	-
2142			SG		1,461,372	405,612	-	-
2143								
2144								
2145	**Total Plant Held For Future Use**			**B10**	**11,192,650**	**4,968,037**	**-**	**-**
2146								
2147	114	Electric Plant Acquisition Adjustments						
2148			S		11,763,784	-	11,763,784	-
2149			SG		144,704,699	40,163,621	144,704,699	40,163,621
2150			SG		-	-	-	-
2151	**Total Electric Plant Acquisition Adjustment**			**B15**	**156,468,483**	**40,163,621**	**156,468,483**	**40,163,621**

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
2152								
2153	115	Accum Provision for Asset Acquisition Adjustments						
2154			S		(3,104,083)	-	(3,104,083)	-
2155			SG		(142,164,204)	(39,458,492)	(142,239,555)	(39,479,406)
2156			SG		-	-	-	-
2157				B15	(145,268,287)	(39,458,492)	(145,343,638)	(39,479,406)
2158								
2159	128	Pensions						
2160			SO		158,341,112	44,191,249	-	-
2161	**Total Pensions**			**B15**	**158,341,112**	**44,191,249**	**-**	**-**
2162								
2163	124	Weatherization						
2164			S		465,169	-	465,169	-
2165			SO		-	-	-	-
2166				B16	465,169	-	465,169	-
2167								
2168	182W	Weatherization						
2169			S		350,035,460	-	350,035,460	-
2170			SG		-	-	-	-
2171			SGCT		-	-	-	-
2172			SO		-	-	-	-
2173				B16	350,035,460	-	350,035,460	-
2174								
2175	186W	Weatherization						
2176			S		-	-	-	-
2177			CN		-	-	-	-
2178			CNP		-	-	-	-
2179			SG		-	-	-	-
2180			SO		-	-	-	-
2181				B16	-	-	-	-
2182								
2183	**Total Weatherization**			**B16**	**350,500,629**	**-**	**350,500,629**	**-**
2184								
2185	151	Fuel Stock						
2186			DEU		-	-	-	-
2187			SE		297,728,656	79,859,122	347,164,314	93,119,143
2188			SE		-	-	-	-
2189			SE		-	-	-	-
2190				B13	297,728,656	79,859,122	347,164,314	93,119,143
2191								
2192	152	Fuel Stock - Undistributed						
2193			SE		-	-	-	-
2194					-	-	-	-
2195								
2196	25316	UAMPS Working Capital Deposit						
2197			SE		-	-	(6,559,077)	(1,759,327)
2198				B13	-	-	(6,559,077)	(1,759,327)
2199								
2200	25317	DG&T Working Capital Deposit						
2201			SE		-	-	(5,684,852)	(1,524,836)
2202				B13	-	-	(5,684,852)	(1,524,836)
2203								
2204	25319	Provo Working Capital Deposit						
2205			SE		-	-	-	-
2206					-	-	-	-
2207								
2208	**Total Fuel Stock**			**B13**	**297,728,656**	**79,859,122**	**334,920,385**	**89,834,980**
2209	154	Materials and Supplies						
2210			S		439,887,578	196,859,862	439,887,578	196,859,862
2211			SG		159,383,503	44,237,807	159,383,503	44,237,807
2212			SE		-	-	-	-
2213			SO		(2,775,992)	(774,749)	(2,775,992)	(774,749)
2214			SG		-	-	-	-
2215			SG		-	-	-	-
2216			SNPD		(1,618,347)	(413,942)	(1,618,347)	(413,942)
2217			SG		-	-	-	-
2218			SG		-	-	-	-
2219			SG		-	-	-	-
2220			SG		-	-	-	-
2221			SG		-	-	-	-
2222			SG		-	-	-	-
2223				B13	594,876,742	239,908,978	594,876,742	239,908,978
2224								
2225	158	WA GHG Allocation Inventory						
2226			S		76,629,359	-	76,629,359	-
2227								
2228				B13	76,629,359	-	76,629,359	-

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
2229								
2230	25318	Provo Working Capital Deposit						
2231			SG		-	-	-	-
2232								
2233				B13	-	-	-	-
2234								
2235	**Total Materials and Supplies**			**B13**	**671,506,101**	**239,908,978**	**671,506,101**	**239,908,978**
2236								
2237	165	Prepayments						
2238			S		13,818,775	6,166,939	13,818,775	6,166,939
2239			GPS		80,059	22,360	80,059	22,360
2240			SG		6,660,844	1,848,756	6,660,844	1,848,756
2241			SE		(88,954)	(23,860)	(88,954)	(23,860)
2242			SO		154,231,659	43,044,346	154,231,659	43,044,346
2243	**Total Prepayments**			**B15**	**174,702,384**	**51,058,541**	**174,702,384**	**51,058,541**
2244								
2245	182M	Misc Regulatory Assets						
2246			S		1,333,879,849	(748,239)	1,330,203,065	-
2247			SG		11,490,613	3,189,286	(0)	(0)
2248			SGCT		-	-	-	-
2249			SG-P		-	-	-	-
2250			SE		155,925,391	41,823,535	82,931,611	22,244,569
2251			SG		-	-	-	-
2252			SO		316,969,335	88,462,628	116,709,610	32,572,358
2253				B16	1,818,265,189	132,727,210	1,529,844,286	54,816,928
2254								
2255	186M	Misc Deferred Debits						
2256			S		6,599,943	-	6,599,943	-
2257			SG		-	-	-	-
2258			SG		-	-	-	-
2259			SG		137,666,377	38,210,094	136,270,370	37,822,624
2260			SO		1,006,304	280,848	1,006,304	280,848
2261			SE		306,510	82,215	306,510	82,215
2262			SG		-	-	-	-
2263			EXCTAX		-	-	-	-
2264	**Total Misc. Deferred Debits**			**B11**	**145,579,134**	**38,573,157**	**144,183,127**	**38,185,687**
2265								
2266	Working Capital							
2267	CWC	Cash Working Capital						
2268			S		89,375,839	37,944,013	64,396,835	36,514,128
2269			SO		-	-	-	-
2270			SE		-	-	-	-
2271				B14	89,375,839	37,944,013	64,396,835	36,514,128
2272								
2273	OWC	Other Work. Cap.						
2274	131	Cash	SNP		-	-	-	-
2275	135	Working Funds	SG		-	-	-	-
2276	141	Notes Receivable	SO		-	-	-	-
2277	143	Other A/R	SO		154,209,947	43,038,287	154,209,947	43,038,287
2278	232	A/P	S		(256,969)	-	(256,969)	-
2279	232	A/P	SO		(7,452,820)	(2,079,999)	(7,452,820)	(2,079,999)
2280	232	A/P	SE		(7,451,576)	(1,998,720)	(7,451,576)	(1,998,720)
2281	232	A/P	SG		(4,704,205)	(1,305,679)	(4,704,205)	(1,305,679)
2282	2533	Other Msc. Df. Crd.	S		-	-	-	-
2283	2533	Other Msc. Df. Crd.	SE		(10,619,764)	(2,848,517)	(9,849,796)	(2,641,990)
2284	2533	Other Msc. Df. Crd.	SO		-	-	-	-
2285	253	Other Msc. Df. Crd.	SE		-	-	-	-
2286	230	Asset Retir. Oblig.	SG		-	-	-	-
2287	230	Asset Retir. Oblig.	S		(2,032,458)	-	(2,032,458)	-
2288	254	Decom. Reg Liability	SG		-	-	(32,435,550)	(9,002,673)
2289	254	Reclam. Reg Liability	SE		-	-	-	-
2290	2533	Cholla Reclamation	SE		-	-	-	-
2291				B14	121,692,157	34,805,372	90,026,575	26,009,225
2292								
2293	**Total Working Capital**			**B14**	**211,067,996**	**72,749,385**	**154,423,410**	**62,523,353**
2294	Miscellaneous Rate Base							
2295	18221	Unrec Plant & Reg Study Costs						
2296			S		-	-	-	-
2297								
2298					-	-	-	-
2299								
2300	18222	Nuclear Plant - Trojan						
2301			S		-	-	-	-
2302			TROJP		-	-	-	-
2303			TROJD		-	-	-	-
2304				B16	-	-	-	-

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
2305								
2306								
2307								
2308	1869	Misc Deferred Debits						
2309			S		-	-	(14,356,267)	(14,356,267)
2310			SG		-	-	-	-
2311					-	-	(14,356,267)	(14,356,267)
2312								
2313	**Total Miscellaneous Rate Base**			**B15**	**-**	**-**	**(14,356,267)**	**(14,356,267)**
2314								
2315	**Total Rate Base Additions**				**3,850,084,046**	**664,740,807**	**3,356,848,899**	**522,656,415**
2316	235	Customer Service Deposits						
2317			S		-	-	-	-
2318			CN		-	-	-	-
2319	**Total Customer Service Deposits**			B15	**-**	**-**	**-**	**-**
2320								
2321	2281	Prop Ins	S		718,959	48,747,812	718,959	48,747,812
2322	2282	Inj & Dam	SO		(1,380,942,925)	(385,405,863)	-	-
2323	2283	Pen & Ben	SO		(753,363)	(210,255)	(753,363)	(210,255)
2324	2282	Prov for Injuries & Da	S		506,680,000	3,443,229	506,680,000	3,443,229
2325	2281	Prop Ins	SO		(2,028,750)	(566,202)	-	-
2326	25335	Reg Liabilities	SE		(79,856,959)	(21,419,862)	(79,856,959)	(21,419,862)
2327				B15	(956,183,038)	(355,411,140)	426,788,637	30,560,924
2328								
2329	22841	Accum Misc. Operating Provisions						
2330			S		-	-	-	-
2331			SG		(234,889)	(65,195)	(234,889)	(65,195)
2332				B15	(234,889)	(65,195)	(234,889)	(65,195)
2333								
2334	254105	ARO	S		-	-	-	-
2335	230	ARO	TROJD		(7,998,127)	(2,206,591)	(7,998,127)	(2,206,591)
2336	254	Reg Liabilities	SO		(51,542,521)	(14,384,946)	(51,542,521)	(14,384,946)
2337	254		S		(1,299,972,624)	(326,375,801)	(1,275,948,568)	(302,351,746)
2338				B15	(1,359,513,272)	(342,967,339)	(1,335,489,217)	(318,943,284)
2339								
2340	252	Customer Advances for Construction						
2341			S		(65,755,439)	(64,843,129)	(50,727,686)	(10,054,115)
2342			SE		-	-	-	-
2343			SG		(267,276,376)	(74,184,094)	(282,304,129)	(78,355,133)
2344			SO		-	-	-	-
2345			CN		-	-	-	-
2346	**Total Customer Advances for Construction**			**B20**	**(333,031,816)**	**(139,027,223)**	**(333,031,816)**	**(88,409,248)**
2347								
2348	25398	SO2 Emissions						
2349			SE		-	-	-	-
2350					-	-	-	-
2351								
2352	25399	Other Deferred Credits						
2353			S		149,643	(149,453)	149,643	(149,453)
2354			SO		(51,614,757)	(14,405,106)	(51,614,757)	(14,405,106)
2355			SG		(186,295,559)	(51,707,403)	(186,295,559)	(51,707,403)
2356			SE		(1,059,601)	(284,215)	(1,059,601)	(284,215)
2357				B15	(238,820,274)	(66,546,177)	(238,820,274)	(66,546,177)
2358								
2359	190	Accumulated Deferred Income Taxes						
2360			S		329,148,902	67,699,247	321,399,581	61,529,569
2361			CN		-	-	-	-
2362			SO		433,122,596	120,879,716	62,923,221	17,561,174
2363			DGP		-	-	-	-
2364			IBT		-	-	-	-
2365			SG		-	-	-	-
2366			SG		-	-	-	-
2367			BADDEBT		5,461,226	2,333,070	5,371,150	2,294,589
2368			TROJD		1,201,724	331,542	1,207,691	333,188
2369			SG		649,223	180,196	9,182,705	2,548,712
2370			SE		24,681,262	6,620,202	5,676,441	1,522,580
2371			SNP		-	-	-	-
2372			SNPD		672,009	171,887	3,154,869	806,955
2373			SG		-	-	-	-
2374				B19	794,936,943	198,215,859	408,915,659	86,596,767
2375								
2376	281	Accumulated Deferred Income Taxes						
2377			S		-	-	-	-
2378			SG		(104,695,016)	(29,058,703)	-	-
2379			SG		-	-	-	-
2380				B19	(104,695,016)	(29,058,703)	-	-

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
2381								
2382	282	Accumulated Deferred Income Taxes						
2383			S		66,623,499	11,771,262	(550,296,152)	(83,200,282)
2384			DITBAL		(3,134,532,755)	(808,051,718)	15	4
2385			SNP		(427,751)	(113,596)	(427,751)	(113,596)
2386			SO		-	-	(107,861,492)	(30,102,947)
2387			GPS		-	-	-	-
2388			CIAC		-	-	-	-
2389			SNPD		-	-	-	-
2390			SCHMDEXP		-	-	-	-
2391			TAXDEPR		-	-	-	-
2392			SG		-	-	-	-
2393			IBT		-	-	-	-
2394			SG		-	-	-	-
2395			CN		-	-	-	-
2396			SE		(929,588)	(249,341)	(273,957)	(73,483)
2397			SG		-	-	(2,658,038,905)	(737,753,973)
2398				B19	(3,069,266,594)	(796,643,393)	(3,316,898,242)	(851,244,277)
2399								
2400	283	Accumulated Deferred Income Taxes						
2401			S		(400,358,371)	(1,365,699)	(225,225,136)	(1,516,241)
2402			SG		(3,593,746)	(997,465)	(1,270,249)	(352,565)
2403			SE		(25,892,552)	(6,945,104)	(1,439,677)	(386,161)
2404			SO		(137,564,388)	(38,392,696)	(32,000,508)	(8,930,987)
2405			GPS		(7,334,333)	(2,048,447)	(7,486,718)	(2,091,007)
2406			SNP		(380,208)	(100,970)	(369,850)	(98,219)
2407			TROJD		-	-	-	-
2408			SG		-	-	-	-
2409			SG		-	-	-	-
2410			SG		-	-	-	-
2411				B19	(575,123,598)	(49,850,380)	(267,792,138)	(13,375,181)
2412								
2413	**Total Accum Deferred Income Tax**			**B19**	**(2,954,148,265)**	**(677,336,618)**	**(3,175,774,720)**	**(778,022,691)**
2414	255	Accumulated Investment Tax Credit						
2415			S		(1,800,221)	-	(469,238)	-
2416			ITC84		-	-	-	-
2417			ITC85		-	-	-	-
2418			ITC86		-	-	-	-
2419			ITC88		-	-	-	-
2420			ITC89		-	-	-	-
2421			ITC90		-	-	-	-
2422			SG		(146,354)	(40,621)	(93,723)	(26,013)
2423	**Total Accumulated ITC**			**B19**	**(1,946,575)**	**(40,621)**	**(562,961)**	**(26,013)**
2424								
2425	**Total Rate Base Deductions**				**(5,843,878,129)**	**(1,581,394,313)**	**(4,657,125,239)**	**(1,221,451,684)**
2426								
2427								
2428								
2429	108SP	Steam Prod Plant Accumulated Depr						
2430			S		(126,704,591)	(1,070,726)	(125,633,865)	-
2431			SG		-	-	-	-
2432			SG		-	-	-	-
2433			SG		(4,393,953,167)	(1,219,566,952)	(6,049,553,958)	(1,679,088,466)
2434			SG		-	-	-	-
2435			SG		-	-	-	-
2436				B17	(4,520,657,758)	(1,220,637,678)	(6,175,187,822)	(1,679,088,466)
2437								
2438	108NP	Nuclear Prod Plant Accumulated Depr						
2439			SG		-	-	-	-
2440			SG		-	-	-	-
2441			SG		-	-	-	-
2442				B17	-	-	-	-
2443								
2444								
2445	108HP	Hydraulic Prod Plant Accum Depr						
2446			S		-	-	-	-
2447			SG		-	-	-	-
2448			SG		-	-	-	-
2449			SG		(368,720,672)	(102,340,542)	(415,929,560)	(115,443,640)
2450			SG		(126,399,616)	(35,082,940)	(140,832,124)	(39,088,765)
2451			SG		(7,198,384)	(1,997,953)	(17,893,097)	(4,966,332)
2452				B17	(502,318,671)	(139,421,434)	(574,654,781)	(159,498,737)
2453								
2454	108XP	Solar Prod Plant Accum Depr						
2455			S		(95,706)	(10,885)	(383,257)	(250,088)
2456			SG		(67,257)	(18,667)	(67,257)	(18,667)
2457				B17	(162,962)	(29,552)	(450,514)	(268,755)
2458								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	JUNE 2025 UNADJUSTED RESULTS OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	DECEMBER 2027 NORMALIZED RESULTS OREGON
2459	108WP	Wind Prod Plant Accum Depr						
2460			S		-	-	(149,452,701)	(149,452,701)
2461			SG		(160,358,936)	(44,508,544)	(515,040,842)	(142,952,545)
2462				B17	(160,358,936)	(44,508,544)	(664,493,543)	(292,405,247)
2463								
2464	108RP	Other Renewable Prod Plant Accum Depr						
2465			S		-	-	-	-
2466			SG		(101,699,389)	(28,227,250)	(107,717,078)	(29,897,494)
2467				B17	(101,699,389)	(28,227,250)	(107,717,078)	(29,897,494)
2468								
2469	108OP	Other Production Plant - Accum Depr						
2470			S		-	-	-	-
2471			SG		-	-	-	-
2472			SG		-	-	-	-
2473			SG		(735,733,959)	(204,207,189)	(833,460,220)	(231,331,674)
2474			SG		-	-	-	-
2475				B17	(735,733,959)	(204,207,189)	(833,460,220)	(231,331,674)
2476								
2477	108EP	Experimental Plant - Accum Depr						
2478			SG		-	-	-	-
2479			SG		-	-	-	-
2480					-	-	-	-
2481								
2482	**Total Production Plant Accum Depreciation**			**B17**	**(6,020,931,676)**	**(1,637,031,647)**	**(8,355,963,959)**	**(2,392,490,373)**
2483								
2484	Summary of Prod Plant Depreciation by Factor							
2485		S			(126,800,296)	(1,081,611)	(275,469,823)	(149,702,789)
2486		DGP			-	-	-	-
2487		DGU			-	-	-	-
2488		SG			(5,894,131,379)	(1,635,950,036)	(8,080,494,136)	(2,242,787,584)
2489		SSGCH			-	-	-	-
2490		SSGCT			-	-	-	-
2491	Total of Prod Plant Depreciation by Factor				(6,020,931,676)	(1,637,031,647)	(8,355,963,959)	(2,392,490,373)
2492								
2493								
2494	108TP	Transmission Plant Accumulated Depr						
2495			S		-	-	0	0
2496			SG		-	-	-	-
2497			SG		-	-	-	-
2498			SG		(2,617,610,617)	(726,532,869)	(2,986,638,199)	(828,958,596)
2499	**Total Trans Plant Accum Depreciation**			**B17**	**(2,617,610,617)**	**(726,532,869)**	**(2,986,638,199)**	**(828,958,596)**
2500	108360	Land and Land Rights						
2501			S		(11,302,855)	(2,545,610)	(14,522,244)	(3,371,639)
2502				B17	(11,302,855)	(2,545,610)	(14,522,244)	(3,371,639)
2503								
2504	108361	Structures and Improvements						
2505			S		(41,047,247)	(10,686,319)	(47,182,559)	(12,260,514)
2506				B17	(41,047,247)	(10,686,319)	(47,182,559)	(12,260,514)
2507								
2508	108362	Station Equipment						
2509			S		(410,970,178)	(113,181,294)	(461,964,960)	(126,265,511)
2510				B17	(410,970,178)	(113,181,294)	(461,964,960)	(126,265,511)
2511								
2512	108363	Storage Battery Equipment						
2513			S		(76,147,932)	(27,724,094)	(84,393,922)	(29,839,846)
2514			CN		(10,802,634)	(3,255,887)	(10,802,634)	(3,255,887)
2515			SNPD		(28,952,540)	(7,405,507)	(31,082,684)	(7,950,357)
2516				B17	(115,903,106)	(38,385,487)	(126,279,240)	(41,046,090)
2517								
2518	108364	Poles, Towers & Fixtures						
2519			S		(772,298,806)	(283,867,224)	(844,907,597)	(302,470,250)
2520				B17	(772,298,806)	(283,867,224)	(844,907,597)	(302,470,250)
2521								
2522	108365	Overhead Conductors						
2523			S		(384,980,442)	(149,168,001)	(431,653,913)	(161,143,458)
2524				B17	(384,980,442)	(149,168,001)	(431,653,913)	(161,143,458)
2525								
2526	108366	Underground Conduit						
2527			S		(205,530,815)	(54,361,730)	(227,196,137)	(59,920,607)
2528				B17	(205,530,815)	(54,361,730)	(227,196,137)	(59,920,607)
2529								
2530	108367	Underground Conductors						
2531			S		(438,463,933)	(108,313,956)	(488,346,613)	(121,112,830)
2532				B17	(438,463,933)	(108,313,956)	(488,346,613)	(121,112,830)
2533								
2534	108368	Line Transformers						
2535			S		(673,186,272)	(272,018,629)	(741,768,530)	(289,615,432)
2536				B17	(673,186,272)	(272,018,629)	(741,768,530)	(289,615,432)
2537								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
2538	108369	Services						
2539			S		(434,405,556)	(167,541,098)	(478,468,871)	(178,846,843)
2540				B17	(434,405,556)	(167,541,098)	(478,468,871)	(178,846,843)
2541								
2542	108370	Meters						
2543			S		(134,702,141)	(43,010,549)	(147,354,150)	(46,256,795)
2544				B17	(134,702,141)	(43,010,549)	(147,354,150)	(46,256,795)
2545								
2546								
2547								
2548	108371	Installations on Customers' Premises						
2549			S		(7,317,227)	(2,110,909)	(7,665,504)	(2,200,269)
2550				B17	(7,317,227)	(2,110,909)	(7,665,504)	(2,200,269)
2551								
2552	108372	Leased Property						
2553			S		-	-	-	-
2554				B17	-	-	-	-
2555								
2556	108373	Street Lights						
2557			S		(33,885,188)	(12,321,462)	(36,502,578)	(12,993,031)
2558				B17	(33,885,188)	(12,321,462)	(36,502,578)	(12,993,031)
2559								
2560	108D00	Unclassified Dist Plant - Acct 300						
2561			S		-	-	-	-
2562				B17	-	-	-	-
2563								
2564	108DS	Unclassified Dist Sub Plant - Acct 300						
2565			S		-	-	-	-
2566				B17	-	-	-	-
2567								
2568	108DP	Unclassified Dist Sub Plant - Acct 300						
2569			S		5,633,788	1,460,620	5,633,788	1,460,620
2570				B17	5,633,788	1,460,620	5,633,788	1,460,620
2571								
2572								
2573	**Total Distribution Plant Accum Depreciation**			**B17**	**(3,658,359,979)**	**(1,256,051,649)**	**(4,048,179,107)**	**(1,356,042,651)**
2574								
2575	Summary of Distribution Plant Depr by Factor							
2576		S			(3,618,604,805)	(1,245,390,255)	(4,006,293,789)	(1,344,836,407)
2577								
2578	Total Distribution Depreciation by Factor				(3,618,604,805)	(1,245,390,255)	(4,006,293,789)	(1,344,836,407)
2579	108GP	General Plant Accumulated Depr						
2580			S		(243,175,391)	(68,887,615)	(262,678,824)	(68,620,248)
2581			SG		-	-	165,454	45,923
2582			SG		-	-	513,009	142,389
2583			SG		(62,906,146)	(17,459,962)	(60,300,157)	(16,736,655)
2584			CN		(209,784,783)	(63,228,605)	(222,176,030)	(66,963,296)
2585			SO		(513,990,979)	(143,449,185)	(596,683,846)	(166,527,847)
2586			SE		(1,598,780)	(428,837)	(1,561,399)	(418,811)
2587			SG		-	-	-	-
2588			SG		-	-	-	-
2589				B17	(1,031,456,080)	(293,454,205)	(1,142,721,792)	(319,078,546)
2590								
2591								
2592	108MP	Mining Plant Accumulated Depr.						
2593			S		-	-	-	-
2594			SE		-	-	-	-
2595				B17	-	-	-	-
2596	108MP	Less Centralia Situs Depreciation						
2597			S		-	-	-	-
2598				B17	-	-	-	-
2599								
2600	1081390	Accum Depr - Capital Lease						
2601			SO	B17	-	-	-	-
2602					-	-	-	-
2603								
2604		Remove Capital Leases			-	-	-	-
2605				B17	-	-	-	-
2606								
2607	1081399	Accum Depr - Capital Lease						
2608			S		-	-	-	-
2609			SE	B17	-	-	-	-
2610					-	-	-	-
2611								
2612		Remove Capital Leases			-	-	-	-
2613				B17	-	-	-	-
2614								
2615								
2616	**Total General Plant Accum Depreciation**			**B17**	**(1,031,456,080)**	**(293,454,205)**	**(1,142,721,792)**	**(319,078,546)**
2617								
2618								
2619								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
2620	Summary of General Depreciation by Factor							
2621		S			(243,175,391)	(68,887,615)	(262,678,824)	(68,620,248)
2622		DGP			-	-	-	-
2623		DGU			-	-	-	-
2624		SE			(1,598,780)	(428,837)	(1,561,399)	(418,811)
2625		SO			(513,990,979)	(143,449,185)	(596,683,846)	(166,527,847)
2626		CN			(209,784,783)	(63,228,605)	(222,176,030)	(66,963,296)
2627		SG			(62,906,146)	(17,459,962)	(59,621,694)	(16,548,344)
2628		DEU			-	-	-	-
2629		SSGCT			-	-	-	-
2630		SSGCH			-	-	-	-
2631		Remove Capital Leases			-	-	-	-
2632	Total General Depreciation by Factor				(1,031,456,080)	(293,454,205)	(1,142,721,792)	(319,078,546)
2633								
2634								
2635	**Total Accum Depreciation - Plant In Service**			**B17**	**(13,328,358,351)**	**(3,913,070,370)**	**(16,533,503,057)**	**(4,896,570,165)**
2636	111OP	Accum Prov for Amort-Other						
2637			S		-	-	-	-
2638			SG		-	-	-	-
2639				B18	-	-	-	-
2640								
2641								
2642	111GP	Accum Prov for Amort-General						
2643			S		(13,135,244)	(5,253,064)	(13,495,928)	(5,403,828)
2644			CN		-	-	-	-
2645			SG		-	-	-	-
2646			SO		(1,875,315)	(523,380)	(1,943,674)	(542,458)
2647			SE		-	-	-	-
2648				B18	(15,010,559)	(5,776,444)	(15,439,603)	(5,946,286)
2649								
2650								
2651	111HP	Accum Prov for Amort-Hydro						
2652			SG		-	-	-	-
2653			SG		-	-	-	-
2654			SG		(4,393,786)	(1,219,521)	(5,023,251)	(1,394,232)
2655			SG		-	-	-	-
2656				B18	(4,393,786)	(1,219,521)	(5,023,251)	(1,394,232)
2657								
2658								
2659	111XP	Accum Prov for Amort-Solar						
2660			S		(279,419)	(279,419)	(279,419)	(279,419)
2661			SG		-	-	-	-
2662				B18	(279,419)	(279,419)	(279,419)	(279,419)
2663								
2664	111WP	Accum Prov for Amort-Wind						
2665			S		-	-	-	-
2666			SG		-	-	-	-
2667				B18	-	-	-	-
2668								
2669	111RP	Accum Prov for Amort-Other Renewable						
2670			S		-	-	-	-
2671			SG		-	-	-	-
2672				B18	-	-	-	-
2673								
2674	111IP	Accum Prov for Amort-Intangible Plant						
2675			S		(1,962,072)	(157,116)	(2,120,862)	(170,171)
2676			SG		-	-	-	-
2677			SG		-	-	18,570	5,154
2678			SE		-	-	-	-
2679			SG		(83,406,888)	(23,150,061)	(88,082,469)	(24,447,795)
2680			SG		(51,222,738)	(14,217,165)	(56,588,688)	(15,706,515)
2681			SG		(7,408,884)	(2,056,378)	(7,595,160)	(2,108,080)
2682			CN		-	-	3,178,870	958,104
2683			SG		-	-	-	-
2684			SG		-	-	-	-
2685			SO		-	-	13,908,637	3,881,746
2686				B18	(144,000,582)	(39,580,721)	(137,281,100)	(37,587,557)
2687	111IP	Less Non-Regulated Plant						
2688			OTH		-	-	-	-
2689					(144,000,582)	(39,580,721)	(137,281,100)	(37,587,557)
2690								
2691	111390	Accum Amtr - Capital Lease						
2692			S		-	-	-	-
2693			SG		-	-	-	-
2694			SO		-	-	-	-
2695				B9	-	-	-	-
2696								
2697		Remove Capital Lease Amtr			-	-	-	-
2698								
2699	**Total Accum Provision for Amortization**			**B18**	**(163,684,346)**	**(46,856,104)**	**(158,023,373)**	**(45,207,495)**
2700								
2701								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2025 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS TOTAL	 OREGON
2702								
2703								
2704	Summary of Amortization by Factor							
2705		S			(15,376,735)	(5,689,599)	(15,896,209)	(5,853,418)
2706		DGP			-	-	-	-
2707		DGU			-	-	-	-
2708		SE			-	-	-	-
2709		SO			(1,875,315)	(523,380)	11,964,963	3,339,288
2710		CN			-	-	3,178,870	958,104
2711		SSGCT			-	-	-	-
2712		SSGCH			-	-	-	-
2713		SG			(146,432,296)	(40,643,125)	(157,270,997)	(43,651,469)
2714		Less Capital Lease			-	-	-	-
2715	Total Provision For Amortization by Factor				(163,684,346)	(46,856,104)	(158,023,373)	(45,207,495)

Tab 3 - Revenue

PacifiCorp **Page 3.0.1**
Oregon General Rate Case – December 2027
Revenue Adjustment Index

The Company used actual revenue for the 12 months ended June 30, 2025 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 2027 test period.

3.1 Pro Forma Revenues
3.2 REC Revenue
3.3 Wheeling Revenue

PacifiCorp
Oregon General Rate Case - December 2027
Tab 3 Adjustment Summary

		Total Adjustments	3.1 Pro Forma Revenues	3.2 REC Revenues_CONF	3.3 Wheeling Revenue
1	Operating Revenues:				
2	General Business Revenues	(24,444,721)	(24,444,721)	-	-
3	Interdepartmental	-	-	-	-
4	Special Sales	-	-	-	-
5	Other Operating Revenues	(4,007,373)	-	(3,001,862)	(1,005,511)
6	Total Operating Revenues	(28,452,094)	(24,444,721)	(3,001,862)	(1,005,511)
7					
8	Operating Expenses:				
9	Steam Production	-	-	-	-
10	Nuclear Production	-	-	-	-
11	Hydro Production	-	-	-	-
12	Solar Production	-	-	-	-
13	Wind Production	-	-	-	-
14	Other Renewable Production	-	-	-	-
15	Other Power Supply	-	-	-	-
16	Transmission	-	-	-	-
17	Distribution	-	-	-	-
18	Customer Accounting	-	-	-	-
19	Customer Service & Info	-	-	-	-
20	Sales	-	-	-	-
21	Administrative & General	-	-	-	-
22					
23	Total O&M Expenses	-	-	-	-
24					
25	Depreciation	-	-	-	-
26	Amortization	-	-	-	-
27	Taxes Other Than Income	-	-	-	-
28	Income Taxes - Federal	(5,702,527)	(4,899,347)	(601,650)	(201,530)
29	Income Taxes - State	(1,291,464)	(1,109,566)	(136,257)	(45,641)
30	Income Taxes - Def Net	-	-	-	-
31	Investment Tax Credit Adj.	-	-	-	-
32	Misc Revenue & Expense	-	-	-	-
33					
34	Total Operating Expenses:	(6,993,991)	(6,008,913)	(737,907)	(247,171)
35					
36	Operating Rev For Return:	(21,458,103)	(18,435,808)	(2,263,955)	(758,340)
37					
38	Rate Base:				
39	Electric Plant In Service	-	-	-	-
40	Plant Held for Future Use	-	-	-	-
41	Misc Deferred Debits	-	-	-	-
42	Elec Plant Acq Adj	-	-	-	-
43	Nuclear Fuel	-	-	-	-
44	Prepayments	-	-	-	-
45	Fuel Stock	-	-	-	-
46	Material & Supplies	-	-	-	-
47	Working Capital	(212,206)	(182,317)	(22,389)	(7,499)
48	Weatherization Loans	-	-	-	-
49	Misc Rate Base	-	-	-	-
50					
51	Total Electric Plant:	(212,206)	(182,317)	(22,389)	(7,499)
52					
53	Rate Base Deductions:				
54	Accum Prov For Deprec	-	-	-	-
55	Accum Prov For Amort	-	-	-	-
56	Accum Def Income Tax	-	-	-	-
57	Unamortized ITC	-	-	-	-
58	Customer Adv For Const	-	-	-	-
59	Customer Service Deposits	-	-	-	-
60	Misc Rate Base Deductions	-	-	-	-
61					
62	Total Rate Base Deductions	-	-	-	-
63					
64	Total Rate Base:	(212,206)	(182,317)	(22,389)	(7,499)
65					
66	Return on Rate Base	-0.351%	-0.302%	-0.037%	-0.012%
67					
68	Return on Equity	-0.703%	-0.604%	-0.074%	-0.025%
69					
70	TAX CALCULATION:				
71	Operating Revenue	(28,452,094)	(24,444,721)	(3,001,862)	(1,005,511)
72	Other Deductions		-	-	-
73	Interest (AFUDC)	-	-	-	-
74	Interest	(5,740)	(4,932)	(606)	(203)
75	Schedule "M" Additions	-	-	-	-
76	Schedule "M" Deductions	-	-	-	-
77	Income Before Tax	(28,446,354)	(24,439,789)	(3,001,256)	(1,005,309)
78					
79	State Income Taxes	(1,291,464)	(1,109,566)	(136,257)	(45,641)
80	Taxable Income	(27,154,890)	(23,330,223)	(2,864,999)	(959,668)
81					
82	Federal Income Taxes + Other	(5,702,527)	(4,899,347)	(601,650)	(201,530)
	APPROXIMATE PRICE CHANGE	29,446,997	25,301,657	3,105,211	1,040,129

PacifiCorp PAGE 3.1
Oregon General Rate Case - December 2027
Pro Forma Revenues

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Residential	440	3	($68,556,056)	OR	Situs	(68,556,056)	3.1.1
Commercial	442	3	57,596,121	OR	Situs	57,596,121	3.1.1
Industrial[1]	442	3	($11,924,462)	OR	Situs	(11,924,462)	3.1.1
Public St. & Hwy	444	3	($1,560,324)	OR	Situs	(1,560,324)	3.1.1
Total			(24,444,721)			(24,444,721)	3.1.1

[1]Includes Irrigation

Description of Adjustment:

This adjustment normalizes general business revenues by adjusting to the pro forma revenue level for the 12 months ending December 2027 based on forecasted loads. Page 3.1.4 shows a breakout between the TAM and general rate case revenues.

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Revenues
Actual 12 Months Ended June 2025
Forecast 12 Months Ending December 2027

	A	B	C	D	E	F	G	H	I	J	K	L	M
	Total Revenue	Normalizing Adjustments[1] (305 Report)	Unadjusted Revenues	Remove Tariff Riders[2]	Actual Base Rate Revenues	Normalizing Adjustments[3]	Temperature Normalization	Total Type 1 Adjusted Revenue	Type 2 Annualized Price Change[4]	Total Type 2 Adjusted Revenue	Type 3 Pro Forma Price Change[5]	Total Oregon Forecast Revenue	**Total Adjustment**
Residential	$888,649,163	($390,650)	$888,258,513	($86,645,218)	$801,613,295	$12,885,896	($245,322)	$814,253,869	($625,999)	$813,627,870	$6,074,586	$819,702,456	**($68,556,056)**
Commercial	$801,662,573	($54,075,576)	$747,586,997	($74,009,693)	$673,577,304	($15,218,245)	($1,364,468)	$656,994,592	$10,873,339	$667,867,931	$137,315,188	$805,183,118	**$57,596,121**
Industrial	$158,479,007	($13,163,349)	$145,315,658	($12,910,116)	$132,405,542	($402,632)	$0	$132,002,910	$4,463,889	$136,466,799	($8,757,995)	$127,708,805	**($17,606,854)**
Irrigation	$32,091,524	($945,243)	$31,146,281	($3,460,747)	$27,685,534	$3,673,158	$146,369	$31,505,061	$2,642,399	$34,147,459	$2,681,214	$36,828,673	**$5,682,392**
Public St & Hwy	$5,638,567	($240,088)	$5,398,480	($483,682)	$4,914,798	($1,055,675)	$0	$3,859,123	$2,201	$3,861,324	($23,169)	$3,838,155	**($1,560,324)**
Total Oregon	$1,886,520,834	($68,814,905)	**$1,817,705,929**	($177,509,455)	$1,640,196,474	($117,497)	($1,463,421)	$1,638,615,555	$17,355,829	$1,655,971,384	$137,289,824	$1,793,261,208	**($24,444,721)**
Source / Formula	305 Report			Ref. 3.1.8 - B	C + D	Ref. 3.1.9	Ref. 3.1.9	E + F + G	Ref. 3.1.9	H + I	Ref. 3.1.9	J + K	L - C **To. 3.1**

[1] Solar Feed-In Revenue, Community Solar Revenue, Other Customer Retail Revenue, Revenue Adjustment I&D Reserve, DSM, Blue Sky, BPA.

[2] Revenue Accounting Adjustments, Customer Bill Credits, BPA (Sch98), Wildfire Mitigation and Vegetation Management Adjustment (Sch 94), Property Sales Adjustment (Sch 96), Intervenor Fund Adjustment (Sch 97), Wildfire Mitigation Plan Cost Recovery Adjustment (Sch 190), Deferred Accounting Adjustment (Sch 192), Replaced Meter Deferred Amounts Adjustment (194), Renewable Resource Deferral Adjustment (Sch 203), Oregon Solar Incentive Program (Sch 204), Power Cost Adjustment Mechanism Adjustment (Sch 206) and Community Solar Adjustment (207).

[3] Removal of Irrigation Demand Charge Accrual (net zero for calendar year), Rate Mitigation Adjustment (299), & Out of Period adjustment

[4] Includes rate changes for: General Rate Case (GRC) and Transition Adjustment Mechanism (TAM) effective January 1, 2025 Includes adjustment bringing direct access consumers to cost of service.

[5] TAM and Renewable Adjustment Clause (RAC) rate change effective January 1, 2026; adjustment to forecast.

Exhibit PAC/802
McCoy/53

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Revenues
Adjustment to MWhs
Historical 12 Months Ended June 2025; Forecast 12 Months Ended December 2027

	A	B	C	D	E	F	G	H
	Total MWhs	Normalizing Adjustments MWhs[1]	Temperature Adjustments MWhs	Type 1 Adjusted MWhs	Type 2 Adjustments MWhs[2]	Total Oregon Adjusted Actual MWhs	Type 3 Adjustment MWhs[3]	Total Oregon Forecast MWhs
Residential	5,846,620	204	(128,799)	5,718,025	214	5,718,239	236	5,718,475
Commercial	6,836,101	1,470	(17,724)	6,819,847	147,974	6,967,821	1,748,016	8,715,838
Industrial	1,394,520	11,521	0	1,406,041	70,532	1,476,573	(113,388)	1,363,185
Irrigation	224,847	(3,155)	1,075	222,767	(14)	222,753	23,136	245,889
Public St & Hwy	29,495	(122)	0	29,372	(0)	29,372	(484)	28,888
Total Oregon	14,331,583	9,917	(145,448)	14,196,053	218,706	14,414,759	1,657,516	16,072,275
Source / Formula	305 Report	Table 2	Table 2	A + B + C	Table 2	D + E	Table 2	F + G

[1] Out of Period adjustment.
[2] Adjustment made to reconcile booked MWh with blocking MWh. Includes adjustment to incorporate direct access MWh.
[3] Adjustment from actual to forecast.

Exhibit PAC/802
McCoy/54

PacifiCorp Page 3.1.3
Oregon General Rate Case - December 2027
Pro Forma Revenues
Present TAM Revenues In Rates
Forecast 12 Months Ended December 31, 2027

Base Rate Schedule	MWH	TAM Collection (Schedule 201 Revenue)
4	5,580,023	$210,932,029
23	1,107,088	$39,483,080
28	1,971,881	$69,647,739
29	1,126	$36,490
30	1,270,076	$44,073,437
41	225,796	$7,635,233
47	35,271	$1,125,475
48	1,948,928	$64,649,991
848	0	$0
49	3,894,623	$123,369,424
15	7,817	$85,926
51	20,175	$297,043
53	8,105	$79,750
54	1,365	$13,429
Total	16,072,275	$561,429,046

Comparison to UE 450	MWH	Approved TAM
2026 Test Period	15,878,954	$557,039,507
Difference resulting from change in test period	193,321	$4,389,539
Percentage Change	1.2%	0.8%

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Revenues
Revenue split between TAM and GRC Proforma Revenue

Total Revenue - 2027	TAM/ NPC	NON-TAM / NON NPC
$1,793,261,208	$561,429,046	$1,231,832,162
Ref 3.1.1	Ref 3.1.3	

The above calculation shows the split of proforma revenue between the TAM and the General Rate Case.

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Revenues
Historical 12 Months Ended June 2025; Forecast 12 Months Ended December 2027
Revenue, kWh and Customer Adjustments

	CUSTOMERS			KWH				
					Type 1			
	305 Average Customers	Adjustment Customers	Forecast Customers	305 Booked kWh	Normalizing Adjustment kWh	Temperature Adjustments kWh	Type 1 Adjustments kWh	Total Type 1 Adjusted kWh
Residential								
15	2,171	-78	2,094	1,747,485	17,458		17,458	1,764,943
4	544,491	13,193	557,684	5,727,307,693	122,686	(126,758,677)	(126,635,991)	5,600,671,702
23	17,159	212	17,371	93,837,791	46,144	(2,040,445)	(1,994,301)	91,843,490
28	213	5	218	43,369,345	17,444		17,444	43,386,789
BPA Balancing Account	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Other Customer Retail Rev	0			0			0	0
Community Solar Revenue	0			0			0	0
Revenue Adjustment - I&D Reserve	0			0			0	0
DSM	0			0			0	0
Blue Sky	0			0			0	0
Unbilled	0			(19,642,000)			0	(19,642,000)
Paperless Credit	0			0			0	0
AGA	0			0			0	0
Total Residential	**564,034**	**13,332**	**577,367**	**5,846,620,314**	**203,732**	**(128,799,121)**	**(128,595,389)**	**5,718,024,925**
Commercial								
15	3,685	-44	3,641	5,933,697	(4,302)		(4,302)	5,929,395
23	68,000	1,729	69,729	1,081,100,394	(374,135)	(4,983,164)	(5,357,299)	1,075,743,095
28	9,707	316	10,022	1,908,838,272	(1,296,114)	(8,202,692)	(9,498,806)	1,899,339,466
30	701	15	716	1,051,495,643	(759,320)	(4,537,903)	(5,297,223)	1,046,198,420
47	5	0	5	36,974,492	827,000		827,000	37,801,492
48	109	11	120	2,670,208,335	3,062,600	0	3,062,600	2,673,270,935
54	97	-1	96	1,353,280	14,019		14,019	1,367,299
848	1	0	1	0	0		0	0
BPA Balancing Account	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Community Solar Revenue								
Other Customer Retail Rev								
Revenue Adjustment - I&D Reserve	0			0			0	0
DSM	0			0			0	0
Blue Sky	0			0			0	0
Unbilled	0			80,197,000			0	80,197,000
Paperless Credit	0			0			0	0
AGA	0			0			0	0
Total Commercial	**82,304**	**2,025**	**84,330**	**6,836,101,113**	**1,469,748**	**(17,723,758)**	**(16,254,010)**	**6,819,847,103**
Industrial								
15	106	1	107	220,976	353		353	221,329
23	949	-3	946	17,000,037	16,462	0	16,462	17,016,499
28	378	5	383	72,725,043	(341,150)	0	(341,150)	72,383,893
30	119	4	123	160,074,631	456,300		456,300	160,530,931
47	1	0	1	5,640,000	0		0	5,640,000
48	78	-1	77	1,190,297,542	11,389,100		11,389,100	1,201,686,642
BPA Balancing Account	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Community Solar Revenue	0			0			0	0
Other Customer Retail Rev	0			0			0	0
Revenue Adjustment - I&D Reserve	0			0			0	0
DSM	0			0			0	0
Blue Sky	0			0			0	0
Unbilled	0			(51,438,000)			0	(51,438,000)
Paperless Credit	0			0			0	0
AGA	0			0			0	0
Total Industrial	**1,630**	**7**	**1,637**	**1,394,520,229**	**11,521,065**	**0**	**11,521,065**	**1,406,041,294**
Irrigation								
41	7,856	-48	7,808	209,213,263	(3,330,871)	1,022,164	(2,308,707)	206,904,556
23	1	-1	0	2,001	(2,001)		(2,001)	0
48	3	0	3	19,945,600	177,600	53,118	230,718	20,176,318
BPA Balancing Account	0			0			0	0
BPA Adjustment	0			0			0	0
Demand Charge Accrual	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Community Solar Revenue	0			0			0	0
Other Customer Retail Rev	0			0			0	0
Revenue Adjustment - I&D Reserve	0			0			0	0
DSM	0			0			0	0
Blue Sky	0			0			0	0
Unbilled	0			(4,314,000)			0	(4,314,000)
Paperless Credit	0			0			0	0
AGA	0			0			0	0
Total Irrigation	**7,860**	**(49)**	**7,811**	**224,846,864**	**(3,155,272)**	**1,075,282**	**(2,079,990)**	**222,766,874**
Lighting								
15	0	0	0	0	0		0	0
23	15	0	15	553,122	51,219		51,219	604,341
51	1,284	21	1,306	20,648,844	(28,531)		(28,531)	20,620,313
53	302	0	302	8,127,733	(145,026)		(145,026)	7,982,707
Solar Feed-In Revenue	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Community Solar Revenue	0			0			0	0
Other Customer Retail Rev	0			0			0	0
DSM	0			0			0	0
Unbilled	0			165,000			0	165,000
Paperless Credit	0			0			0	0
AGA	0			0			0	0
Total Lighting	**1,601**	**21**	**1,623**	**29,494,699**	**(122,338)**	**0**	**(122,338)**	**29,372,361**
TOTAL COMPANY	**657,429**	**15,337**	**672,767**	**14,331,583,219**	**9,916,935**	**(145,447,597)**	**(135,530,662)**	**14,196,052,557**

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Revenues
Historical 12 Months Ended June 2025; Foreca
Revenue, kWh and Customer Adjustments

	KWH		KWH		REVENUES			
						Type 1		
	Type 2		Type 3					
	Blocking Adjustment kWh	Total Type 2 Adjusted kWh	Forecast Adjustment kWh	Total Type 3 Adjusted kWh	305 Booked Revenues	Remove Tariff Riders $	Actual Base Rate Revenues	Normalizing Adjustments $
Residential								
15	(94)	1,764,849	(72,691)	1,692,158	$310,382	($23,052)	$287,330	($42,723)
4	214,931	5,600,886,633	(20,863,196)	5,580,023,438	$825,238,485	($44,638,420)	$780,600,066	$12,888,881
23	(865)	91,842,625	(882,658)	90,959,967	$16,184,153	($887,126)	$15,297,027	$308,899
28	19	43,386,808	2,412,342	45,799,150	$4,628,309	($281,715)	$4,346,594	($269,161)
BPA Balancing Account		0		0	($1,382,677)	$1,382,677	$0	$0
Solar Feed-In Revenue		0		0	$1,324,800	($1,324,800)	$0	$0
Revenue Accounting Adjustment		0		0	($8,942,760)	$8,942,760	$0	$0
Other Customer Retail Rev		0		0	$705,193	($705,193)	$0	$0
Community Solar Revenue		0		0	$703,200	($703,200)	$0	$0
Revenue Adjustment - I&D Reserve		0		0	$1,618,829	($1,618,829)	$0	$0
DSM		0		0	$44,007,509	($44,007,509)	$0	$0
Blue Sky		0		0	$1,423,819	($1,423,819)	$0	$0
Unbilled		(19,642,000)	19,642,000	0	$2,816,000	$0	$2,816,000	$0
Paperless Credit		0		0	$0	($1,747,644)	($1,747,644)	$0
AGA		0		0	$13,922	$0	$13,922	$0
Total Residential	**213,991**	**5,718,238,916**	**235,797**	**5,718,474,713**	**$888,649,163**	**($87,035,868)**	**$801,613,295**	**$12,885,896**
Commercial								
15	(269)	5,929,126	(37,365)	5,891,761	$842,016	($80,890)	$761,126	($137,335)
23	538,246	1,076,281,341	(76,299,589)	999,981,752	$165,699,063	($18,962,070)	$146,736,994	$3,374,961
28	5,689,333	1,905,028,799	(47,618,204)	1,857,410,595	$221,115,150	($23,131,425)	$197,983,725	($11,802,973)
30	51,664,448	1,097,862,868	16,920,035	1,114,782,903	$112,896,735	($11,294,294)	$101,602,441	($6,654,920)
47	0	37,801,492	(3,634,408)	34,167,084	$4,670,431	($357,271)	$4,313,160	$55,224
48	90,082,600	2,763,353,535	1,938,885,351	4,702,238,886	$226,949,008	($26,109,481)	$200,839,527	($12,397)
54	0	1,367,299	(2,613)	1,364,686	$145,330	($13,794)	$131,536	($40,804)
848	0	0	0	0	$1,937,454	($418,024)	$1,519,430	$0
BPA Balancing Account		0		0	($29,525)	$29,525	$0	$0
Solar Feed-In Revenue		0		0	$1,342,696	($1,342,696)	$0	$0
Revenue Accounting Adjustment		0		0	($7,591,265)	$7,591,265	$0	$0
Community Solar Revenue					$772,290	($772,290)	$0	$0
Other Customer Retail Rev					$857,888	($857,888)	$0	$0
Revenue Adjustment - I&D Reserve		0		0	$2,080,022	($2,080,022)	$0	$0
DSM		0		0	$48,455,930	($48,455,930)	$0	$0
Blue Sky		0		0	$1,605,991	($1,605,991)	$0	$0
Unbilled		80,197,000	(80,197,000)	0	$17,155,000	$0	$17,155,000	$0
Paperless Credit		0		0	$0	($223,994)	($223,994)	$0
AGA		0		0	$2,758,359	$0	$2,758,359	$0
Total Commercial	**147,974,358**	**6,967,821,461**	**1,748,016,206**	**8,715,837,667**	**$801,662,573**	**($128,085,269)**	**$673,577,304**	**($15,218,245)**
Industrial								
15	(6)	221,323	11,898	233,221	$25,190	($2,663)	$22,527	($4,396)
23	89	17,016,588	(1,478,643)	15,537,945	$2,648,086	($302,701)	$2,345,385	$56,841
28	30	72,383,923	(2,586,426)	69,797,497	$8,977,914	($902,995)	$8,074,919	($468,667)
30	1,029,333	161,560,264	(6,267,203)	155,293,061	$19,008,187	($1,740,282)	$17,267,905	($878,912)
47	0	5,640,000	(4,536,000)	1,104,000	$1,227,615	($49,271)	$1,178,344	($813)
48	69,502,400	1,271,189,042	(149,969,370)	1,121,219,672	$112,453,180	($12,069,046)	$100,384,134	$893,315
BPA Balancing Account		0		0	($16)	$16	$0	$0
Solar Feed-In Revenue		0		0	$281,981	($281,981)	$0	$0
Revenue Accounting Adjustment		0		0	($2,161,718)	$2,161,718	$0	$0
Community Solar Revenue		0		0	$166,847	($166,847)	$0	$0
Other Customer Retail Rev		0		0	$175,405	($175,405)	$0	$0
Revenue Adjustment - I&D Reserve		0		0	$891,081	($891,081)	$0	$0
DSM		0		0	$10,900,265	($10,900,265)	$0	$0
Blue Sky		0		0	$748,966	($748,966)	$0	$0
Unbilled		(51,438,000)	51,438,000	0	($3,668,000)	$0	($3,668,000)	$0
Paperless Credit		0		0	$0	($3,698)	($3,698)	$0
AGA		0		0	$6,804,026	$0	$6,804,026	$0
Total Industrial	**70,531,846**	**1,476,573,140**	**(113,387,744)**	**1,363,185,396**	**$158,479,007**	**($26,073,465)**	**$132,405,542**	**($402,632)**
Irrigation								
41	(13,731)	206,890,825	18,905,589	225,796,414	$27,958,861	($2,746,079)	$25,212,782	$3,841,731
23	0	0	0	0	$512	($26)	$486	($486)
48	0	20,176,318	(83,671)	20,092,647	$1,932,002	($155,258)	$1,776,744	$14,913
BPA Balancing Account		0		0	($24,299)	$24,299	$0	$0
BPA Adjustment		0		0	$23,708	($23,708)	$0	$0
Demand Charge Accrual		0		0	$183,000	$0	$183,000	($183,000)
Solar Feed-In Revenue		0		0	$38,186	($38,186)	$0	$0
Revenue Accounting Adjustment		0		0	($287,267)	$287,267	$0	$0
Community Solar Revenue		0		0	$24,686	($24,686)	$0	$0
Other Customer Retail Rev		0		0	$24,815	($24,815)	$0	$0
Revenue Adjustment - I&D Reserve		0		0	$118,818	($118,818)	$0	$0
DSM		0		0	$1,571,650	($1,571,650)	$0	$0
Blue Sky		0		0	$648	($648)	$0	$0
Unbilled		(4,314,000)	4,314,000	0	$388,000	$0	$388,000	$0
Paperless Credit		0		0	$0	($13,681)	($13,681)	$0
AGA		0		0	$138,203	$0	$138,203	$0
Total Irrigation	**(13,731)**	**222,753,143**	**23,135,918**	**245,889,061**	**$32,091,524**	**($4,405,989)**	**$27,685,534**	**$3,673,158**
Lighting								
15	0	0	0	0	$0	$0	$0	$0
23	0	604,341	4,314	608,655	$159,524	($7,643)	$151,881	$15,162
51	(211)	20,620,102	(445,298)	20,174,804	$4,523,581	($440,152)	$4,083,430	($870,148)
53	(55)	7,982,652	122,016	8,104,668	$716,336	($74,575)	$641,761	($200,688)
Solar Feed-In Revenue		0		0	$3,336	($3,336)	$0	$0
Revenue Accounting Adjustment		0		0	($40,961)	$40,961	$0	$0
Community Solar Revenue		0		0	$1,613	($1,613)	$0	$0
Other Customer Retail Rev		0		0	$3,728	($3,728)	$0	$0
DSM		0		0	$231,411	($231,411)	$0	$0
Unbilled		165,000	(165,000)	0	$40,000	$0	$40,000	$0
Paperless Credit		0		0	$0	($2,273)	($2,273)	$0
AGA		0		0	$0	$0	$0	$0
Total Lighting	**(266)**	**29,372,095**	**(483,968)**	**28,888,127**	**$5,638,567**	**($723,769)**	**$4,914,798**	**($1,055,675)**
TOTAL COMPANY	**218,706,198**	**14,414,758,755**	**1,657,516,210**	**16,072,274,964**	**$1,886,520,834**	**($246,324,360)**	**$1,640,196,474**	**($117,497)**

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Revenues
Historical 12 Months Ended June 2025; Foreca
Revenue, kWh and Customer Adjustments

	REVENUES					
	Type 1		Type 2		Type 3	
	Temperature Adjustment $	Total Type 1 Adjusted Revenues	Type 2 Adjustments $	Total Type 2 Adjusted Revenues	Type 3 Adjustments $	Total Adjusted Revenues
Residential						
15		$244,607	$839	$245,446	($4,851)	$240,595
4	$0	$793,488,947	($1,218,455)	$792,270,492	$8,541,724	$800,812,216
23	($245,322)	$15,360,604	$616,882	$15,977,486	$63,055	$16,040,541
28	$0	$4,077,433	($25,265)	$4,052,168	$290,658	$4,342,826
BPA Balancing Account		$0		$0		$0
Solar Feed-In Revenue		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Other Customer Retail Rev		$0		$0		$0
Community Solar Revenue		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Blue Sky		$0		$0		$0
Unbilled		$2,816,000		$2,816,000	($2,816,000)	$0
Paperless Credit		($1,747,644)	$0	($1,747,644)		($1,747,644)
AGA		$13,922		$13,922		$13,922
Total Residential	**($245,322)**	**$814,253,869**	**($625,999)**	**$813,627,870**	**$6,074,586**	**$819,702,456**
Commercial						
15		$623,791	$1,809	$625,600	$6,857	$632,457
23	($586,496)	$149,525,458	$4,524,127	$154,049,585	($7,886,022)	$146,163,563
28	($560,914)	$185,619,838	($716,482)	$184,903,356	($1,487,620)	$183,415,736
30	($217,058)	$94,730,463	$2,939,606	$97,670,069	$3,207,642	$100,877,711
47		$4,368,383	$400,741	$4,769,125	($394,408)	$4,374,717
48	$0	$200,827,130	$2,746,115	$203,573,245	$161,599,213	$365,172,458
54		$90,732	($150)	$90,582	$1,582	$92,164
848		$1,519,430	$977,574	$2,497,004	($577,057)	$1,919,947
BPA Balancing Account		$0		$0		$0
Solar Feed-In Revenue		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Community Solar Revenue		$0		$0		$0
Other Customer Retail Rev		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Blue Sky		$0		$0		$0
Unbilled		$17,155,000		$17,155,000	($17,155,000)	$0
Paperless Credit		($223,994)	$0	($223,994)		($223,994)
AGA		$2,758,359		$2,758,359		$2,758,359
Total Commercial	**($1,364,468)**	**$656,994,592**	**$10,873,339**	**$667,867,931**	**$137,315,188**	**$805,183,118**
Industrial						
15		$18,132	$289	$18,420	$1,046	$19,466
23	$0	$2,402,226	$72,684	$2,474,910	($165,116)	$2,309,794
28	$0	$7,606,252	$29,786	$7,636,038	($152,591)	$7,483,447
30		$16,388,993	$147,486	$16,536,479	($363,518)	$16,172,961
47		$1,177,531	$129,964	$1,307,495	($1,006,699)	$300,796
48		$101,277,449	$4,083,680	$105,361,129	($10,739,117)	$94,622,012
BPA Balancing Account		$0		$0		$0
Solar Feed-In Revenue		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Community Solar Revenue		$0		$0		$0
Other Customer Retail Rev		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Blue Sky		$0		$0		$0
Unbilled		($3,668,000)		($3,668,000)	$3,668,000	$0
Paperless Credit		($3,698)	$0	($3,698)		($3,698)
AGA		$6,804,026		$6,804,026		$6,804,026
Total Industrial	**$0**	**$132,002,910**	**$4,463,889**	**$136,466,799**	**($8,757,995)**	**$127,708,805**
Irrigation						
41	$143,672	$29,198,184	$2,591,735	$31,789,919	$3,105,704	$34,895,623
23	$0	$0	$0	$0	$0	$0
48	$2,697	$1,794,354	$50,664	$1,845,018	($36,490)	$1,808,528
BPA Balancing Account		$0		$0		$0
BPA Adjustment		$0		$0		$0
Demand Charge Accrual		$0		$0		$0
Solar Feed-In Revenue		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Community Solar Revenue		$0		$0		$0
Other Customer Retail Rev		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Blue Sky		$0		$0		$0
Unbilled		$388,000		$388,000	($388,000)	$0
Paperless Credit		($13,681)	$0	($13,681)		($13,681)
AGA		$138,203		$138,203		$138,203
Total Irrigation	**$146,369**	**$31,505,061**	**$2,642,399**	**$34,147,459**	**$2,681,214**	**$36,828,673**
Lighting						
15		$0	$0	$0	$0	$0
23		$167,042	$11,670	$178,712	$1,437	$180,149
51		$3,213,282	($6,267)	$3,207,014	($1,996)	$3,205,018
53		$441,073	($3,201)	$437,871	$17,390	$455,261
Solar Feed-In Revenue		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Community Solar Revenue		$0		$0		$0
Other Customer Retail Rev		$0		$0		$0
DSM		$0		$0		$0
Unbilled		$40,000		$40,000	($40,000)	$0
Paperless Credit		($2,273)	$0	($2,273)		($2,273)
AGA		$0		$0		$0
Total Lighting	**$0**	**$3,859,123**	**$2,201**	**$3,861,324**	**($23,169)**	**$3,838,155**
TOTAL COMPANY	**($1,463,421)**	**$1,638,615,555**	**$17,355,829**	**$1,655,971,384**	**$137,289,824**	**$1,793,261,208**

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Revenues
Historical 12 Months Ended June 2025; Forecast 12 Months Ended December 2027
Revenue Adjustments

		Remove Tariff Riders													
	305 Booked Revenues	Remove Accounting Adjustments	Paperless Billing Credit Sch 300	Sch 98 BPA Adjust	Sch 94 WMVM Adjust	Sch 96 Prop Sales Adjust	Sch 97 Intv Fnd Adj Adjust	190 WMP Adjust	192 Def. Acct. Adjust	194 Repl. Meter Def. Adjust	Sch 203 Renw Rsrc Def Adjust	Sch 204 OSIP Adjust	Sch 206 PCAM Adjust	Sch 207 Com. Sol. Adjust	**Total Remove Tariff Riders**
Residential															
15	$310,382		$0	$4,469	($6,493)	($25)	$0	($13,297)	($1,736)	($192)	($208)	($84)	($5,438)	($48)	($23,052)
4	$825,238,485		$1,708,794	$46,983,429	($12,449,567)	$0	($1,775,465)	($26,085,528)	($9,820,178)	($1,890,012)	($3,264,565)	($1,267,015)	($36,091,036)	($687,277)	($44,638,420)
23	$16,184,153		$38,371	$765,323	($230,873)	$0	$0	($480,611)	($153,719)	($31,905)	($50,672)	($19,419)	($712,360)	($11,261)	($887,126)
28	$4,628,309		$479	$256,801	($43,523)	$0	$0	($92,078)	($34,564)	($10,842)	($22,986)	($8,897)	($321,332)	($4,771)	($281,715)
BPA Balancing Account	($1,382,677)			$1,382,677											$1,382,677
Solar Feed-In Revenue	$1,324,800	($1,324,800)													($1,324,800)
Revenue Accounting Adjustment	($8,942,760)	$8,942,760													$8,942,760
Other Customer Retail Rev	$705,193	($705,193)													($705,193)
Community Solar Revenue	$703,200	($703,200)													($703,200)
Revenue Adjustment - I&D Reserve	$1,618,829	($1,618,829)													($1,618,829)
DSM	$44,007,509	($44,007,509)													($44,007,509)
Blue Sky	$1,423,819	($1,423,819)													($1,423,819)
Unbilled	$2,816,000														$0
Paperless Credit	$0		($1,747,644)												($1,747,644)
AGA	$13,922														$0
Total Residential	**$888,649,163**	**($40,840,590)**	**$0**	**$49,392,700**	**($12,730,456)**	**($25)**	**($1,775,465)**	**($26,671,514)**	**($10,010,198)**	**($1,932,951)**	**($3,338,431)**	**($1,295,416)**	**($37,130,165)**	**($703,356)**	**($87,035,868)**
Commercial															
15	$842,016		$0	$3,254	($19,842)	($47)	$0	($40,660)	($5,345)	($586)	($635)	($258)	($16,624)	($147)	($80,890)
23	$165,699,063		$193,327	$179,337	($2,696,491)	$0	$0	($5,562,630)	($1,725,079)	($367,699)	($583,993)	($221,679)	($8,047,387)	($129,776)	($18,962,070)
28	$221,115,150		$27,715	$401,663	($1,934,347)	$0	$0	($4,071,598)	($1,501,362)	($478,705)	($1,014,859)	($390,928)	($13,958,374)	($210,631)	($23,131,425)
30	$112,896,735		$2,357	$280,480	($720,783)	$0	$0	($1,549,345)	($674,053)	($253,869)	($573,965)	($217,360)	($7,466,340)	($121,416)	($11,294,294)
47	$4,670,431		$6	$0	($13,882)	$0	($8,874)	($31,182)	($18,195)	($7,395)	($18,487)	($6,752)	($248,443)	($4,067)	($357,271)
48	$226,949,008		$397	$135,853	($1,022,898)	$0	($662,535)	($2,318,623)	($1,402,803)	($552,112)	($1,380,281)	($509,294)	($18,093,522)	($303,662)	($26,109,481)
54	$145,330		$193	$0	($2,544)	$0	$0	($5,162)	($1,740)	($311)	($514)	($208)	($3,385)	($122)	($13,794)
848	$1,937,454		$0	$0	($83,254)	$0	($52,314)	($182,426)	($100,030)	$0	$0	$0	$0	$0	($418,024)
BPA Balancing Account	($29,525)			$29,525											$29,525
Solar Feed-In Revenue	$1,342,696	($1,342,696)													($1,342,696)
Revenue Accounting Adjustment	($7,591,265)	$7,591,265													$7,591,265
Community Solar Revenue	$772,290	($772,290)													($772,290)
Other Customer Retail Rev	$857,888	($857,888)													($857,888)
Revenue Adjustment - I&D Reserve	$2,080,022	($2,080,022)													($2,080,022)
DSM	$48,455,930	($48,455,930)													($48,455,930)
Blue Sky	$1,605,991	($1,605,991)													($1,605,991)
Unbilled	$17,155,000														$0
Paperless Credit	$0		($223,994)												($223,994)
AGA	$2,758,359														$0
Total Commercial	**$801,662,573**	**($47,523,551)**	**$0**	**$1,030,113**	**($6,494,041)**	**($47)**	**($723,723)**	**($13,761,626)**	**($5,428,608)**	**($1,660,678)**	**($3,572,734)**	**($1,346,479)**	**($47,834,075)**	**($769,820)**	**($128,085,269)**
Industrial															
15	$25,190		$0	$6	($639)	($1)	$0	($1,295)	($159)	($19)	($20)	($8)	($522)	($5)	($2,663)
23	$2,648,086		$2,276	$1,032	($42,027)	$0	$0	($87,374)	($27,801)	($5,780)	($9,180)	($3,516)	($128,291)	($2,040)	($302,701)
28	$8,977,914		$849	$142	($73,155)	$0	$0	($155,095)	($58,606)	($18,181)	($38,544)	($14,969)	($537,435)	($8,000)	($902,995)
30	$19,008,187		$282	$0	($104,126)	$0	$0	($224,746)	($98,626)	($36,817)	($83,239)	($31,611)	($1,143,790)	($17,608)	($1,740,282)
47	$1,227,615		$6	$0	($2,331)	$0	($1,354)	($4,903)	($2,283)	($1,128)	($2,820)	($972)	($32,865)	($620)	($49,271)
48	$112,453,180		$286	$0	($470,166)	$0	($302,352)	($1,059,301)	($629,124)	($251,960)	($629,900)	($231,119)	($8,356,832)	($138,578)	($12,069,046)
BPA Balancing Account	($16)			$16											$16
Solar Feed-In Revenue	$281,981	($281,981)													($281,981)
Revenue Accounting Adjustment	($2,161,718)	$2,161,718													$2,161,718
Community Solar Revenue	$166,847	($166,847)													($166,847)
Other Customer Retail Rev	$175,405	($175,405)													($175,405)
Revenue Adjustment - I&D Reserve	$891,081	($891,081)													($891,081)
DSM	$10,900,265	($10,900,265)													($10,900,265)
Blue Sky	$748,966	($748,966)													($748,966)
Unbilled	($3,668,000)														$0
Paperless Credit	$0		($3,698)												($3,698)
AGA	$6,804,026														$0
Total Industrial	**$158,479,007**	**($11,002,826)**	**$0**	**$1,195**	**($692,444)**	**($1)**	**($303,706)**	**($1,532,714)**	**($816,600)**	**($313,885)**	**($763,703)**	**($282,195)**	**($10,199,735)**	**($166,851)**	**($26,073,465)**
Irrigation															
41	$27,958,861		$13,663	$824,201	($615,383)	$0	$0	($1,205,133)	($224,985)	($73,225)	($108,791)	($37,642)	($1,295,771)	($23,013)	($2,746,079)
23	$512		$6	$0	($6)	$0	$0	($11)	($2)	($1)	($1)	($0)	($11)	($0)	($26)
48	$1,932,002		$12	$8,769	($9,176)	$0	($4,787)	($17,132)	($5,122)	($3,989)	($9,973)	($3,090)	($108,576)	($2,194)	($155,258)
BPA Balancing Account	($24,299)			$24,299											$24,299
BPA Adjustment	$23,708			($23,708)											($23,708)
Demand Charge Accrual	$183,000														$0
Solar Feed-In Revenue	$38,186	($38,186)													($38,186)
Revenue Accounting Adjustment	($287,267)	$287,267													$287,267
Community Solar Revenue	$24,686	($24,686)													($24,686)
Other Customer Retail Rev	$24,815	($24,815)													($24,815)
Revenue Adjustment - I&D Reserve	$118,818	($118,818)													($118,818)
DSM	$1,571,650	($1,571,650)													($1,571,650)
Blue Sky	$648	($648)													($648)
Unbilled	$388,000														$0
Paperless Credit	$0		($13,681)												($13,681)
AGA	$138,203														$0
Total Irrigation	**$32,091,524**	**($1,491,537)**	**$0**	**$833,561**	**($624,565)**	**$0**	**($4,787)**	**($1,222,276)**	**($230,108)**	**($77,214)**	**($118,765)**	**($40,733)**	**($1,404,358)**	**($25,208)**	**($4,405,989)**
Lighting															
15	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	$159,524		$2,273	$0	($1,377)	$0	$0	($2,837)	($886)	($188)	($299)	($114)	($4,150)	($66)	($7,643)
51	$4,523,581		$0	$0	($106,160)	($254)	$0	($216,947)	($28,059)	($4,002)	($3,638)	($1,430)	($78,844)	($819)	($440,152)
53	$716,336		$0	$0	($12,215)	$0	$0	($24,853)	($10,514)	($1,382)	($3,007)	($1,270)	($20,603)	($731)	($74,575)
Solar Feed-In Revenue	$3,336	($3,336)													($3,336)
Revenue Accounting Adjustment	($40,961)	$40,961													$40,961
Community Solar Revenue	$1,613	($1,613)													($1,613)
Other Customer Retail Rev	$3,728	($3,728)													($3,728)
DSM	$231,411	($231,411)													($231,411)
Unbilled	$40,000														$0
Paperless Credit	$0		($2,273)												($2,273)
AGA	$0														$0
Total Lighting	**$5,638,567**	**($199,127)**	**$0**	**$0**	**($119,751)**	**($254)**	**$0**	**($244,637)**	**($39,459)**	**($5,571)**	**($6,944)**	**($2,814)**	**($103,597)**	**($1,616)**	**($723,769)**
TOTAL COMPANY	**$1,886,520,834**	**($101,057,629)**	**$0**	**$51,257,568**	**($20,661,256)**	**($327)**	**($2,807,681)**	**($43,432,766)**	**($16,524,973)**	**($3,990,299)**	**($7,800,577)**	**($2,967,637)**	**($96,671,930)**	**($1,666,851)**	**($246,324,360)**

Exhibit PAC/802
McCoy/60

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Revenues
Historical 12 Months Ended June 2025; Forecast 1
Revenue Adjustments

	Actual Base Rate Revenues	Demand Charge Accrual	Sch 299 RMA Adjust	Out of Period Adjust	Subtotal Normalization Adjustments	Temperature Adjustment	Total Type 1 Adjusted Revenues	Type 2 Price Changes	Total Type 2 Adj.	Total Type 2 Adjusted Revenues	Type 3 Price Changes	Adjustment to Forecast	Total Type 3 Adj.	Total Type 3 Adjusted Revenues
Residential														
15	$287,330		($45,101)	$2,378	($42,723)		$244,607	$839	$839	$245,446	$5,485	($10,336)	($4,851)	$240,595
4	$780,600,066		$12,868,377	$20,505	$12,888,881	$0	$793,488,947	($1,218,455)	($1,218,455)	$792,270,492	$9,180,035	($638,311)	$8,541,724	$800,812,216
23	$15,297,027		$298,158	$10,740	$308,899	($245,322)	$15,360,604	$616,882	$616,882	$15,977,486	$138,797	($75,742)	$63,055	$16,040,541
28	$4,346,594		($271,526)	$2,365	($269,161)		$4,077,433	($25,265)	($25,265)	$4,052,168	$66,382	$224,276	$290,658	$4,342,826
BPA Balancing Account	$0				$0		$0			$0			$0	$0
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Other Customer Retail Rev	$0				$0		$0			$0			$0	$0
Community Solar Revenue	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserve	$0				$0		$0			$0			$0	$0
DSM	$0				$0		$0			$0			$0	$0
Blue Sky	$0				$0		$0			$0			$0	$0
Unbilled	$2,816,000				$0		$2,816,000			$2,816,000		($2,816,000)	($2,816,000)	$0
Paperless Credit	($1,747,644)				$0		($1,747,644)			($1,747,644)			$0	($1,747,644)
AGA	$13,922				$0		$13,922			$13,922			$0	$13,922
Total Residential	**$801,613,295**	**$0**	**$12,849,908**	**$35,988**	**$12,885,896**	**($245,322)**	**$814,253,869**	**($625,999)**	**($625,999)**	**$813,627,870**	**$9,390,699**	**($3,316,113)**	**$6,074,586**	**$819,702,456**
Commercial														
15	$761,126		($137,229)	($106)	($137,335)		$623,791	$1,809	$1,809	$625,600	$10,871	($4,013)	$6,857	$632,457
23	$146,736,994		$3,404,954	($29,993)	$3,374,961	($586,496)	$149,525,458	$4,524,127	$4,524,127	$154,049,585	$1,668,392	($9,554,414)	($7,886,022)	$146,163,563
28	$197,983,725		($11,701,003)	($101,970)	($11,802,973)	($560,914)	$185,619,838	($716,482)	($716,482)	$184,903,356	$2,914,984	($4,402,604)	($1,487,620)	$183,415,736
30	$101,602,441		($6,665,146)	$10,226	($6,654,920)	($217,058)	$94,730,463	$2,939,606	$2,939,606	$97,670,069	$1,647,369	$1,560,273	$3,207,642	$100,877,711
47	$4,313,160		($4,652)	$59,876	$55,224		$4,368,383	$400,741	$400,741	$4,769,125	$52,782	($447,190)	($394,408)	$4,374,717
48	$200,839,527		($290,802)	$278,405	($12,397)	$0	$200,827,130	$2,746,115	$2,746,115	$203,573,245	$3,886,515	$157,712,698	$161,599,213	$365,172,458
54	$131,536		($41,649)	$845	($40,804)		$90,732	($150)	($150)	$90,582	$1,805	($223)	$1,582	$92,164
848	$1,519,430				$0		$1,519,430	$977,574	$977,574	$2,497,004	$0	($577,057)	($577,057)	$1,919,947
BPA Balancing Account	$0				$0		$0			$0			$0	$0
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Community Solar Revenue	$0				$0		$0			$0			$0	$0
Other Customer Retail Rev	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserve	$0				$0		$0			$0			$0	$0
DSM	$0				$0		$0			$0			$0	$0
Blue Sky	$0				$0		$0			$0			$0	$0
Unbilled	$17,155,000				$0		$17,155,000			$17,155,000		($17,155,000)	($17,155,000)	$0
Paperless Credit	($223,994)				$0		($223,994)			($223,994)			$0	($223,994)
AGA	$2,758,359				$0		$2,758,359			$2,758,359			$0	$2,758,359
Total Commercial	**$673,577,304**	**$0**	**($15,435,527)**	**$217,283**	**($15,218,245)**	**($1,364,468)**	**$656,994,592**	**$10,873,339**	**$10,873,339**	**$667,867,931**	**$10,182,718**	**$127,132,470**	**$137,315,188**	**$805,183,118**
Industrial														
15	$22,527		($4,411)	$15	($4,396)		$18,132	$289	$289	$18,420	$56	$990	$1,046	$19,466
23	$2,345,385		$53,950	$2,891	$56,841	$0	$2,402,226	$72,684	$72,684	$2,474,910	$26,315	($191,431)	($165,116)	$2,309,794
28	$8,074,919		($443,254)	($25,413)	($468,667)	$0	$7,606,252	$29,786	$29,786	$7,636,038	$110,817	($263,408)	($152,591)	$7,483,447
30	$17,267,905		($996,738)	$117,826	($878,912)		$16,388,993	$147,486	$147,486	$16,536,479	$242,523	($606,041)	($363,518)	$16,172,961
47	$1,178,344		($813)	$0	($813)		$1,177,531	$129,964	$129,964	$1,307,495	$8,290	($1,014,989)	($1,006,699)	$300,796
48	$100,384,134		($145,378)	$1,038,693	$893,315		$101,277,449	$4,083,680	$4,083,680	$105,361,129	$1,733,903	($12,473,020)	($10,739,117)	$94,622,012
BPA Balancing Account	$0				$0		$0			$0			$0	$0
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Community Solar Revenue	$0				$0		$0			$0			$0	$0
Other Customer Retail Rev	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserve	$0				$0		$0			$0			$0	$0
DSM	$0				$0		$0			$0			$0	$0
Blue Sky	$0				$0		$0			$0			$0	$0
Unbilled	($3,668,000)				$0		($3,668,000)			($3,668,000)		$3,668,000	$3,668,000	$0
Paperless Credit	($3,698)				$0		($3,698)			($3,698)			$0	($3,698)
AGA	$6,804,026				$0		$6,804,026			$6,804,026			$0	$6,804,026
Total Industrial	**$132,405,542**	**$0**	**($1,536,644)**	**$1,134,012**	**($402,632)**	**$0**	**$132,002,910**	**$4,463,889**	**$4,463,889**	**$136,466,799**	**$2,121,904**	**($10,879,899)**	**($8,757,995)**	**$127,708,805**
Irrigation														
41	$25,212,782		$4,221,326	($379,595)	$3,841,731	$143,672	$29,198,184	$2,591,735	$2,591,735	$31,789,919	$299,992	$2,805,712	$3,105,704	$34,895,623
23	$486		$5	($491)	($486)		$0	$0	$0	$0	$0	$0	$0	$0
48	$1,776,744		($3,733)	$18,646	$14,913	$2,697	$1,794,354	$50,664	$50,664	$1,845,018	$27,586	($64,076)	($36,490)	$1,808,528
BPA Balancing Account	$0				$0		$0			$0			$0	$0
BPA Adjustment	$0				$0		$0			$0			$0	$0
Demand Charge Accrual	$183,000	($183,000)			($183,000)		$0			$0			$0	$0
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Community Solar Revenue	$0				$0		$0			$0			$0	$0
Other Customer Retail Rev	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserve	$0				$0		$0			$0			$0	$0
DSM	$0				$0		$0			$0			$0	$0
Blue Sky	$0				$0		$0			$0			$0	$0
Unbilled	$388,000				$0		$388,000			$388,000		($388,000)	($388,000)	$0
Paperless Credit	($13,681)				$0		($13,681)			($13,681)			$0	($13,681)
AGA	$138,203				$0		$138,203			$138,203			$0	$138,203
Total Irrigation	**$27,685,534**	**($183,000)**	**$4,217,598**	**($361,440)**	**$3,673,158**	**$146,369**	**$31,505,061**	**$2,642,399**	**$2,642,399**	**$34,147,459**	**$327,578**	**$2,353,636**	**$2,681,214**	**$36,828,673**
Lighting														
15	$0		$0	$0	$0		$0	$0	$0	$0	$0	$0	$0	$0
23	$151,881		$1,707	$13,455	$15,162		$167,042	$11,670	$11,670	$178,712	$901	$536	$1,437	$180,149
51	$4,083,430		($864,605)	($5,543)	($870,148)		$3,213,282	($6,267)	($6,267)	$3,207,014	$68,736	($70,732)	($1,996)	$3,205,018
53	$641,761		($192,688)	($8,000)	($200,688)		$441,073	($3,201)	($3,201)	$437,871	$10,537	$6,853	$17,390	$455,261
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Community Solar Revenue	$0				$0		$0			$0			$0	$0
Other Customer Retail Rev	$0				$0		$0			$0			$0	$0
DSM	$0				$0		$0			$0			$0	$0
Unbilled	$40,000				$0		$40,000			$40,000		($40,000)	($40,000)	$0
Paperless Credit	($2,273)				$0		($2,273)			($2,273)			$0	($2,273)
AGA	$0				$0		$0			$0			$0	$0
Total Lighting	**$4,914,798**	**$0**	**($1,055,586)**	**($88)**	**($1,055,675)**	**$0**	**$3,859,123**	**$2,201**	**$2,201**	**$3,861,324**	**$80,174**	**($103,343)**	**($23,169)**	**$3,838,155**
TOTAL COMPANY	**$1,640,196,474**	**($183,000)**	**($960,251)**	**$1,025,754**	**($117,497)**	**($1,463,421)**	**$1,638,615,555**	**$17,355,829**	**$17,355,829**	**$1,655,971,384**	**$22,103,073**	**$115,186,751**	**$137,289,824**	**$1,793,261,208**

Exhibit PAC/802
McCoy/61

PacifiCorp
Oregon General Rate Case - December 2027
Confidential REC Revenues

Note: Please see Confidential Exhibit PAC/806_CONF for redacted information.

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Remove June 2025 Booked Revenues (Including Accruals)	456	1	(17,823,609)	SG	27.756%	(4,947,045)	3.2.1
Remove June 2025 REC Deferrals	456	1	6,179,888	SG	27.756%	1,715,263	3.2.1
Remove June 2025 Leaning Juniper Indemnity	456	1	16,440	SG	27.756%	4,563	3.2.1
Add December 2027 Forecasted REC Revenues	456	3	[redacted]	SG	27.756%	[redacted]	3.2.2

Description of Adjustment:

This adjustment removes REC revenue and REC deferrals booked during the 12 months ended June 2025. Most of Oregon's share of the renewable energy credits (RECs) are banked for compliance; however, not all RECs meet the Oregon RPS qualifications. Oregon's revenues from RPS ineligible RECs that are sold are passed backed to customers through the Oregon property sales balancing account per Commission Order No. 10-210 in Docket UP 260. REC revenues received through Schedule 272 are added back into Test Year results on a forecast basis.

PacifiCorp
Oregon General Rate Case - December 2027
Confidential REC Revenues
Actuals as Booked

Posting Date	Fin Accrual	Fin Reversal	Back Office Actual	Kennecott Removal	NET Rec Revenue
FERC Acct (Ref B1)	4562700	4562700	4562700	4562700	
SAP Acct	301944	301944	301945	301945	
July-24	(600,296)	51,398	(50,000)	50,000	(548,898)
August-24	(175,283)	600,296	(598,700)	50,000	(123,687)
September-24	(2,582,070)	1,404,818	(50,000)	50,000	(1,177,251)
October-24	(2,970,748)	2,837,909	(1,227,500)	50,000	(1,310,339)
November-24	(4,101,933)	1,485,374	(1,360,288)	50,000	(3,926,847)
December-24	(798,066)	4,101,933	(4,100,272)	50,000	(746,404)
January-25	(1,737,922)	798,066	(796,525)	50,000	(1,686,381)
February-25	(2,753,359)	1,737,922	(1,737,525)	50,000	(2,702,961)
March-25	(1,355,877)	2,753,359	(2,750,750)	50,000	(1,303,268)
April-25	(2,962,486)	1,355,877	(1,352,500)	50,000	(2,909,109)
May-25	(592,657)	2,962,486	(2,958,750)	50,000	(538,921)
June-25	(904,697)	592,657	(587,500)	50,000	(849,539)
12 ME June 2025 Total	(21,535,394)	20,682,095	(17,570,310)	600,000	(17,823,609)

REC Deferrals Included in Unadjusted Results:

FERC Account 4562700
Amount Yr. Ended June 2025 **6,179,888** **Ref. 3.2**

Leaning Juniper indemnity REC revenue included in unadjusted results:

FERC Account 4562700
Amount Yr. Ended June 2025 **16,440** **Ref. 3.2**

PacifiCorp
Oregon General Rate Case - December 2027
Confidential REC Revenues
Pryor Mountain REC Revenue
Calendar Year 2027 Forecast

Note: Please see Confidential Exhibit PAC/806_CONF for redacted information.

Posting Date	Pryor Mountain Forecast	
January-27	[redacted]	
February-27		
March-27		
April-27		
May-27		
June-27		
July-27		
August-27		
September-27		
October-27		
November-27		
December-27		
12 ME December 2027 Total		**Ref. 3.2**

PacifiCorp PAGE 3.3
Oregon General Rate Case - December 2027
Wheeling Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Other Electric Revenues	456	1	35,029,437	SG	27.756%	9,722,621	3.3.2
Other Electric Revenues	456	1	(783)	SE	26.823%	(210)	3.3.2
Other Electric Revenues	456	2	(36,070,562)	SG	27.756%	(10,011,592)	3.3.2
Other Electric Revenues	456	3	(2,580,855)	SG	27.756%	(716,331)	3.3.2
			(3,622,763)			(1,005,511)	
Adjustment Detail:							
Actual Wheeling Revenues 12 ME June 2025			194,394,512				3.3.2
Total Adjustments			(3,622,763)				Above
Adjusted Wheeling Revenues 12 ME December 2027			190,771,749				3.3.2

Description of Adjustment:

This adjustment removes out-of-period and one-time adjustments from wheeling revenues recorded in 12 months ended June 2025 and adds in pro forma changes through December 2027.

PacifiCorp
Oregon General Rate Case - December 2027
Wheeling Revenue

Customer	Total
Airport Solar LLC	(2,767,156)
Altop Energy Trading LLC	(259,267)
Arizona Electric Power Cooperative, Inc.	(280)
Avangrid Renewables, LLC	(7,756,935)
Avista	-
Basin Electric Power Cooperative	(816,758)
BHG	(1,066)
Black Hills Corporation	(94,148)
Black Hills/Colorado Electric Utility Company	(1,543)
Bonneville Power Administration	(29,122,319)
BP Energy Company	(65,831)
Brookfield Renewable Trading & Marketing LP	-
Calpine Energy Solutions	(957,417)
City of Roseville	(2,387,331)
Clark County PUD	(2,210,560)
Clatskanie Peoples Utility District	(669,038)
Conoco Phillips Company	-
Constellation Energy Generation, LLC (ESS)	(219,429)
Constellation Energy Generation, LLC (Stateline)	(6,442,328)
CP Energy Marketing (US) Inc.	-
Deseret Generation & Trans.	(9,961,055)
Dynasty Power Inc.	(2,682,658)
EDF Trading North America, LLC	(607,544)
Energy Keepers, Inc	(1,132,035)
Eugene Water & Electric Board	-
Evergreen Biopower	(561,668)
Fall River Rural Electric Cooperative	(151,308)
Falls Creek H.P. LP	(236,766)
Foote Creek IV, LLC	-
Garrett Solar LLC	(428,972)
Guzman Energy, LLC	(1,427,762)
Idaho Power Company	(5,160,346)
Idaho Power Company - Power Supply Merchant	1,351,976
Imperial Irrigation District	-
Intermountain Power Agency	-
Klamath Energy LLC	-
Los Angeles Department of Water & Power	-
Macquarie Energy, LLC	(2,238,987)
MAG Energy Solutions, Inc.	(373,073)
Marysville Hydro Partners	-
Mercuria Energy America, LLC	(2,873,301)
Montana-Dakota Utilities Co.	(2,442,314)
Moon Lake Electric Association	(20,424)
Morgan Stanley	(4,518,474)
Navajo Tribal Utility Authority	(647,008)
Nevada Power Company	(140,826)
NextEra Energy Resources, LLC	(657,548)
Ormat Nevada Inc.	(449,131)
Pacific Gas & Electric Company	(25,946)
PACIFICORP	-
PACIFICORP TRANSFER	(0)
Phillips 66 Energy Trading LLC	(14,219,491)

PacifiCorp
Oregon General Rate Case - December 2027
Wheeling Revenue

Customer	Total
Portland General Electric Company	(37,752)
Powerex Corporation	(40,919,704)
Public Services Company of Colorado	(112,932)
Puget Sound Energy, INC	(739,751)
Rainbow Energy Marketing	(870,896)
Sacramento Municipal Utility District	(977,963)
Salt River Project	(1,286,794)
Seattle City Light	(14)
Shell Energy North America	(6,201,134)
Sierra Pacific Power Company	(36,159)
Southern California Edison Company	(5,586,969)
Southern California Public Power Authority	(29,269)
State of South Dakota	(227,729)
TEC Energy Inc.	(19,796)
Tenaska Power Services Co	(2,046,558)
The Energy Authority, Inc.	(1,159,364)
Thermo No. 1 BE-01, LLC	(619,705)
TransAlta Energy Marketing (U.S.) Inc.	(691,908)
Tri-State Generation & Trans.	(972,921)
U.S. Bureau of Reclamation CR	(11,473)
U.S. Bureau of Reclamation FNO	(23,527)
U.S. Bureau of Reclamation WB	(29,226)
Uniper Global Commodities North America LLC	-
Utah Associated Municipal Power Sys OM	-
Utah Associated Municipal Power Systems	(33,751,699)
Utah Municipal Power Agency	(8,837,983)
Vitol Inc.	(449)
Warm Springs Power Enterprises	(119,700)
West Point RNG LLC	(5,643)
Western Area Power Adm CO River	(1,234)
Western Area Power Adm FNO	(97,899)
Western Area Power Adm LAP	(993,388)
Western Area Power Administration	(2,981,768)
SAP Adjustments	18,372,862
Total	**(194,394,512)**
	Ref 3.3

Type

1	Remove refunds and other out of period adjustments	(35,028,653)
2	Annualized Changes	36,070,562
3	Proforma Adjustments	2,580,855

Incremental Adjustments	**3,622,763**
	Ref 3.3
Accum Totals	**(190,771,749)**
	Ref 3.3

Tab 4 - Operation & Maintenance Expense

PacifiCorp **Page 4.0.1**
Oregon General Rate Case – December 2027
Operation & Maintenance Expense Adjustment Index

The Company's June 2025 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 2027 test period. The following adjustments are included:

4.1 Miscellaneous General Expense & Revenue
4.2 Wages & Employee Benefits Adjustment
4.3 Pension Related Non-Service Expense
4.4 Remove Non-Recurring Entries
4.5 Insurance Expense
4.6 Generation Overhaul Expense
4.7 Revenue Sensitive Items & Uncollectible Accounts
4.8 Memberships & Subscriptions
4.9 Meals & Entertainment Adjustment
4.10 O&M Escalation
4.11 Wildfire Mitigation and Vegetation Management Expenses
4.12 Customer Payment Fees

PacifiCorp
Oregon General Rate Case - December 2027
Tab 4 Adjustment Summary

		4.1	4.2	4.3	4.4	4.5	4.6	4.7
	Total Adjustments	Miscellaneous General Expense & Revenue	Wage & Employee Benefits Adjustment	Pension Related Non-Service Expense	Remove Non-Recurring Entries	Insurance Expense	Generation Overhaul Expense	Revenue Sensitive Items & Uncollectible Accounts
1 Operating Revenues:								
2 General Business Revenues	44,283	44,283	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-	-	-
6 Total Operating Revenues	44,283	44,283	-	-	-	-	-	-
7								
8 Operating Expenses:								
9 Steam Production	7,201,933	-	1,945,206	-	-	-	2,389,212	-
10 Nuclear Production	-	-	-	-	-	-	-	-
11 Hydro Production	(299,697)	-	530,279	-	(953,658)	-	-	-
12 Solar Production	24,144	-	82,181	-	-	-	-	-
13 Wind Production	355,570	-	185	-	-	-	-	-
14 Other Renewable Production	20,730	-	6,682	-	-	-	-	-
15 Other Power Supply	947,362	-	839,356	-	-	-	(819,788)	-
16 Transmission	(3,378,890)	-	749,190	-	-	-	-	-
17 Distribution	(17,509,790)	-	4,197,297	-	-	-	-	-
18 Customer Accounting	2,063,311	(85,936)	736,478	-	-	-	-	(151,589)
19 Customer Service & Info	362,895	93,203	220,934	-	-	-	-	-
20 Sales	-	-	-	-	-	-	-	-
21 Administrative & General	(167,125)	1,750,292	560,430	1,535,831	-	(5,409,661)	-	(87,578)
22								
23 Total O&M Expenses	(10,379,558)	1,757,558	9,868,217	1,535,831	(953,658)	(5,409,661)	1,569,424	(239,167)
24								
25 Depreciation	-	-	-	-	-	-	-	-
26 Amortization	-	-	-	-	-	-	-	-
27 Taxes Other Than Income	(584,460)	-	-	-	-	-	-	(584,460)
28 Income Taxes - Federal	21,089,675	(600,224)	(1,979,466)	(308,072)	191,294	20,223,202	(314,811)	165,211
29 Income Taxes - State	4,776,228	(135,934)	(448,294)	(69,770)	43,323	4,579,995	(71,296)	37,416
30 Income Taxes - Def Net	(25,408,597)	-	-	-	-	(25,408,597)	-	-
31 Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
32 Misc Revenue & Expense	1,280,031	1,280,031	-	-	-	-	-	-
33								
34 Total Operating Expenses:	(9,226,682)	2,301,430	7,440,457	1,157,989	(719,041)	(6,015,061)	1,183,317	(620,999)
35								
36 Operating Rev For Return:	9,270,965	(2,257,147)	(7,440,457)	(1,157,989)	719,041	6,015,061	(1,183,317)	620,999
37								
38 Rate Base:								
39 Electric Plant In Service	-	-	-	-	-	-	-	-
40 Plant Held for Future Use	-	-	-	-	-	-	-	-
41 Misc Deferred Debits	-	-	-	-	-	-	-	-
42 Elec Plant Acq Adj	-	-	-	-	-	-	-	-
43 Nuclear Fuel	-	-	-	-	-	-	-	-
44 Prepayments	-	-	-	-	-	-	-	-
45 Fuel Stock	-	-	-	-	-	-	-	-
46 Material & Supplies	-	-	-	-	-	-	-	-
47 Working Capital	452,140	30,990	225,752	35,135	(21,817)	588,422	35,903	(18,842)
48 Weatherization Loans	-	-	-	-	-	-	-	-
49 Misc Rate Base	-	-	-	-	-	-	-	-
50								
51 Total Electric Plant:	452,140	30,990	225,752	35,135	(21,817)	588,422	35,903	(18,842)
52								
53 Rate Base Deductions:								
54 Accum Prov For Deprec	-	-	-	-	-	-	-	-
55 Accum Prov For Amort	-	-	-	-	-	-	-	-
56 Accum Def Income Tax	(95,544,651)	-	-	-	-	(95,544,651)	-	-
57 Unamortized ITC	-	-	-	-	-	-	-	-
58 Customer Adv For Const	-	-	-	-	-	-	-	-
59 Customer Service Deposits	-	-	-	-	-	-	-	-
60 Misc Rate Base Deductions	385,972,065	-	-	-	-	385,972,065	-	-
61								
62 Total Rate Base Deductions	290,427,413	-	-	-	-	290,427,413	-	-
63								
64 Total Rate Base:	290,879,554	30,990	225,752	35,135	(21,817)	291,015,836	35,903	(18,842)
65								
66 Return on Rate Base	-0.088%	-0.037%	-0.122%	-0.019%	0.012%	-0.131%	-0.019%	0.010%
67								
68 Return on Equity	-0.176%	-0.074%	-0.244%	-0.038%	0.024%	-0.263%	-0.037%	0.019%
69								
70 TAX CALCULATION:								
71 Operating Revenue	9,728,270	(2,993,306)	(9,868,217)	(1,535,831)	953,658	5,409,661	(1,569,424)	823,627
72 Other Deductions	-	-	-	-	-	-	-	-
73 Interest (AFUDC)	-	-	-	-	-	-	-	-
74 Interest	7,868,292	838	6,107	950	(590)	7,871,978	971	(510)
75 Schedule "M" Additions	-	-	-	-	-	-	-	-
76 Schedule "M" Deductions	(103,343,273)	-	-	-	-	(103,343,273)	-	-
77 Income Before Tax	105,203,251	(2,994,144)	(9,874,324)	(1,536,782)	954,248	100,880,956	(1,570,395)	824,136
78								
79 State Income Taxes	4,776,228	(135,934)	(448,294)	(69,770)	43,323	4,579,995	(71,296)	37,416
80 Taxable Income	100,427,023	(2,858,210)	(9,426,029)	(1,467,012)	910,925	96,300,960	(1,499,100)	786,720
81								
82 Federal Income Taxes + Other	21,089,675	(600,224)	(1,979,466)	(308,072)	191,294	20,223,202	(314,811)	165,211
APPROXIMATE PRICE CHANGE	17,419,609	3,101,368	10,236,271	1,593,113	(989,226)	21,922,241	1,627,959	(875,399)

PacifiCorp
Oregon General Rate Case - December 2027
Tab 4 Adjustment Summary

		4.8	4.9	4.10	4.11	4.12
		Memberships and Subscriptions	Meals and Entertainment Adjustment	O&M Escalation	Wildfire Mitigation and Vegetation Management Expenses	Customer Payment Fees
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	-	(25,620)	2,893,135	-	-
10	Nuclear Production	-	-	-	-	-
11	Hydro Production	-	(11,295)	134,976	-	-
12	Solar Production	-	-	(58,037)	-	-
13	Wind Production	-	(2,507)	357,892	-	-
14	Other Renewable Production	-	(229)	14,277	-	-
15	Other Power Supply	-	(21,224)	949,018	-	-
16	Transmission	-	(12,451)	435,838	(4,551,466)	-
17	Distribution	-	(127,163)	(482,850)	(21,097,074)	-
18	Customer Accounting	-	(4,285)	317,478	-	1,251,165
19	Customer Service & Info	-	(17,154)	57,706	8,206	-
20	Sales	-	-	-	-	-
21	Administrative & General	(242,829)	(19,855)	1,734,762	713,460	(701,977)
22						
23	Total O&M Expenses	(242,829)	(241,781)	6,354,194	(24,926,874)	549,188
24						
25	Depreciation	-	-	-	-	-
26	Amortization	-	-	-	-	-
27	Taxes Other Than Income	-	-	-	-	-
28	Income Taxes - Federal	48,709	48,499	(1,274,588)	5,000,083	(110,162)
29	Income Taxes - State	11,031	10,984	(288,659)	1,132,380	(24,949)
30	Income Taxes - Def Net	-	-	-	-	-
31	Investment Tax Credit Adj.	-	-	-	-	-
32	Misc Revenue & Expense	-	-	-	-	-
33						
34	Total Operating Expenses:	(183,089)	(182,299)	4,790,947	(18,794,411)	414,078
35						
36	Operating Rev For Return:	183,089	182,299	(4,790,947)	18,794,411	(414,078)
37						
38	Rate Base:					
39	Electric Plant In Service	-	-	-	-	-
40	Plant Held for Future Use	-	-	-	-	-
41	Misc Deferred Debits	-	-	-	-	-
42	Elec Plant Acq Adj	-	-	-	-	-
43	Nuclear Fuel	-	-	-	-	-
44	Prepayments	-	-	-	-	-
45	Fuel Stock	-	-	-	-	-
46	Material & Supplies	-	-	-	-	-
47	Working Capital	(5,555)	(5,531)	145,363	(570,244)	12,564
48	Weatherization Loans	-	-	-	-	-
49	Misc Rate Base	-	-	-	-	-
50						
51	Total Electric Plant:	(5,555)	(5,531)	145,363	(570,244)	12,564
52						
53	Rate Base Deductions:					
54	Accum Prov For Deprec	-	-	-	-	-
55	Accum Prov For Amort	-	-	-	-	-
56	Accum Def Income Tax	-	-	-	-	-
57	Unamortized ITC	-	-	-	-	-
58	Customer Adv For Const	-	-	-	-	-
59	Customer Service Deposits	-	-	-	-	-
60	Misc Rate Base Deductions	-	-	-	-	-
61						
62	Total Rate Base Deductions	-	-	-	-	-
63						
64	Total Rate Base:	(5,555)	(5,531)	145,363	(570,244)	12,564
65						
66	Return on Rate Base	0.003%	0.003%	-0.075%	0.294%	-0.006%
67						
68	Return on Equity	0.006%	0.006%	-0.150%	0.589%	-0.013%
69						
70	TAX CALCULATION:					
71	Operating Revenue	242,829	241,781	(6,354,194)	24,926,874	(549,188)
72	Other Deductions	-	-	-	-	-
73	Interest (AFUDC)	-	-	-	-	-
74	Interest	(150)	(150)	3,932	(15,425)	340
75	Schedule "M" Additions	-	-	-	-	-
76	Schedule "M" Deductions	-	-	-	-	-
77	Income Before Tax	242,979	241,931	(6,358,126)	24,942,300	(549,528)
78						
79	State Income Taxes	11,031	10,984	(288,659)	1,132,380	(24,949)
80	Taxable Income	231,948	230,947	(6,069,467)	23,809,919	(524,579)
81						
82	Federal Income Taxes + Other	48,709	48,499	(1,274,588)	5,000,083	(110,162)
	APPROXIMATE PRICE CHANGE	(251,864)	(250,777)	6,590,609	(25,854,307)	569,621

PacifiCorp PAGE 4.1
Oregon General Rate Case - December 2027
Miscellaneous General Expense & Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Gain on Property Sales	421	1	4,783,245	SO	27.909%	1,334,951	
Gain on Property Sales	421	1	(208,376)	SG	27.756%	(57,836)	
Loss on Property Sales	421	1	10,447	SO	27.909%	2,916	
			4,585,317			1,280,031	4.1.1
Commercial & Industrial	442	1	44,283	OR	Situs	44,283	4.1.1
Adjustment to Expense:							
Office Supplies and Expenses	921	1	(78,611)	SO	27.909%	(21,940)	
Office Supplies and Expenses	921	1	(41,061)	SO	27.909%	(11,460)	
Re-allocate Regulatory Commission	928	1	3,380	SG	27.756%	938	
Re-allocate Regulatory Commission	928	1	(3,380)	OR	Situs	(3,380)	
Credit facility fees	921	1	6,399,871	SO	27.909%	1,786,133	
Payment Services Fees	903	1	(262,229)	CN	30.140%	(79,035)	
Blue Sky	909	1	6,047	OR	Situs	6,047	
Blue Sky	903	1	(6,901)	OR	Situs	(6,901)	
Informational Advertising	909	1	(243,209)	CN	30.140%	(73,303)	
Informational Advertising	909	1	1,222	ID	Situs	-	
Informational Advertising	909	1	823	WY	Situs	-	
Informational Advertising	909	1	405	WA	Situs	-	
Informational Advertising	909	1	79,984	CA	Situs	-	
Informational Advertising	909	1	160,458	OR	Situs	160,458	
			6,016,798			1,757,558	4.1.1
Total Adjustment			10,646,398			3,081,872	

Description of Adjustment:

This adjustment removes from results of operations certain miscellaneous expenses that should have been charged to non-regulated accounts. It also reallocates certain items such as gains and losses on property sales to reflect the appropriate allocation. In addition, it recognizes revenues from the Oregon Customer Opt-Out deferral.

PacifiCorp
Oregon General Rate Case - December 2027
Miscellaneous General Expense & Revenue

Description	FERC	Factor	Amount	
Adjustment to Revenue:				
FERC 421 - (Gain)/Loss on Sale of Utility Plant				
Gain on Property Sales	421	SO	4,783,245	
Gain on Property Sales	421	SG	(208,376)	
Loss on Property Sales	421	SO	10,447	
			4,585,317	**Ref 4.1**
Five-Year Opt-Out Amortization				
Commercial & Industrial (includes Irrigation)	442	OR	44,283	
			44,283	**Ref 4.1**
Non Regulated Flights				
Office Supplies and Expenses	921	SO	**(78,611)**	**Ref 4.1**
FERC 921 - Office Supplies & Expenses				
Office Supplies and Expenses	921	SO	**(41,061)**	**Ref 4.1**
FERC 928 - Regulatory Commission Expenses				
Re-allocate Regulatory Commission	928	SG	3,380	
Re-allocate Regulatory Commission	928	OR	(3,380)	
			-	**Ref 4.1**
Credit Facility Fee Adjustment				
Credit facility fees	921	SO	**6,399,871**	**Ref 4.1**
Payment Services Fees				
Payment Services Fees	903	CN	**(262,229)**	**Ref 4.1**
Informational & Instructional Advertising				
Blue Sky	909	OR	6,047	
Blue Sky	903	OR	(6,901)	
Remove system allocation	909	CN	(243,209)	
Add situs allocation	909	ID	1,222	
Add situs allocation	909	WY	823	
Add situs allocation	909	WA	405	
Add situs allocation	909	CA	79,984	
Add situs allocation	909	OR	160,458	
			(1,171)	**Ref 4.1**
Total Adjustment			**10,646,398**	**Ref 4.1**

PacifiCorp PAGE 4.2
Oregon General Rate Case - December 2027
Wage and Employee Benefits Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Production	500	3	855,016	SG	27.756%	237,315	
Steam Production	502	3	1,395,331	SG	27.756%	387,282	
Steam Production	503	3	7,823	SE	26.823%	2,098	
Steam Production	505	3	890	SG	27.756%	247	
Steam Production	506	3	1,758,003	SG	27.756%	487,944	
Steam Production	510	3	175,673	SG	27.756%	48,759	
Steam Production	511	3	380,900	SG	27.756%	105,721	
Steam Production	512	3	1,524,868	SG	27.756%	423,236	
Steam Production	513	3	756,473	SG	27.756%	209,963	
Steam Production	514	3	153,628	SG	27.756%	42,640	
Hydro Production	535	3	277,288	SG-P	27.756%	76,963	
Hydro Production	535	3	713,207	SG-U	27.756%	197,955	
Hydro Production	536	3	2,921	SG-P	27.756%	811	
Hydro Production	537	3	51,131	SG-P	27.756%	14,192	
Hydro Production	537	3	1,868	SG-U	27.756%	519	
Hydro Production	539	3	334,130	SG-P	27.756%	92,740	
Hydro Production	539	3	375,492	SG-U	27.756%	104,220	
Hydro Production	540	3	51	SG-P	27.756%	14	
Hydro Production	542	3	15,919	SG-P	27.756%	4,418	
Hydro Production	542	3	975	SG-U	27.756%	271	
Hydro Production	543	3	15,793	SG-P	27.756%	4,383	
Hydro Production	543	3	11,377	SG-U	27.756%	3,158	
Hydro Production	544	3	45,532	SG-P	27.756%	12,638	
Hydro Production	544	3	12,296	SG-U	27.756%	3,413	
Hydro Production	545	3	48,793	SG-P	27.756%	13,543	
Hydro Production	545	3	3,759	SG-U	27.756%	1,043	
Other Power Supply	546	3	1,704	SG	27.756%	473	
Other Power Supply	548	3	386,833	SG	27.756%	107,368	
Other Power Supply	549	3	994	OR	Situs	994	
Other Power Supply	549	3	191,938	SG	27.756%	53,274	
Other Power Supply	552	3	67,360	SG	27.756%	18,696	
Other Power Supply	553	3	138,573	SG	27.756%	38,462	
Other Power Supply	554	3	5,564	SG	27.756%	1,544	
Other Power Supply	556	3	41,518	SG	27.756%	11,524	
Other Power Supply	557	3	2,518	ID	Situs	-	
Other Power Supply	557	3	18	OR	Situs	18	
Other Power Supply	557	3	-	SE	26.823%	-	
Other Power Supply	557	3	2,186,964	SG	27.756%	607,004	
Wind Production	558WP	3	667	SG	27.756%	185	
Solar Production	558XP	3	82,181	OR	Situs	82,181	
Other Renewable	559	3	24,073	SG	27.756%	6,682	
Transmission	560	3	615,978	SG	27.756%	170,968	
Transmission	561	3	783,548	SG	27.756%	217,478	
Transmission	562	3	150,178	SG	27.756%	41,683	
Transmission	563	3	38,211	SG	27.756%	10,606	
			13,637,958			3,844,623	

Description of Adjustment:

This adjustment recognizes wage and benefit increases that have occurred during the base period 12 months ended June 2025, or are projected to occur during the twelve month period ending December 2027 for labor charged to operation & maintenance accounts. See page 4.2.5 for more information on how this adjustment was calculated.

PacifiCorp PAGE 4.2.1
Oregon General Rate Case - December 2027
Wage and Employee Benefits Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Transmission	566	3	6,188	SG	27.756%	1,718	
Transmission	567	3	10,760	SG	27.756%	2,986	
Transmission	568	3	106,890	SG	27.756%	29,668	
Transmission	569	3	204,172	SG	27.756%	56,669	
Transmission	570	3	492,629	SG	27.756%	136,732	
Transmission	571	3	290,611	SG	27.756%	80,661	
Transmission	572	3	77	SG	27.756%	21	
Distribution	580	3	57,696	CA	Situs	-	
Distribution	580	3	12,443	ID	Situs	-	
Distribution	580	3	83,241	OR	Situs	83,241	
Distribution	580	3	755,815	SNPD	25.578%	193,323	
Distribution	580	3	43,175	UT	0.000%	-	
Distribution	580	3	8,747	WA	0.000%	-	
Distribution	580	3	9,827	WYP	Situs	-	
Distribution	580	3	5,836	WYU	Situs	-	
Distribution	581	3	1,030,596	SNPD	25.578%	263,607	
Distribution	582	3	4,265	CA	Situs	-	
Distribution	582	3	7,079	ID	Situs	-	
Distribution	582	3	29,213	OR	Situs	29,213	
Distribution	582	3	75,338	UT	Situs	-	
Distribution	582	3	3,693	WA	Situs	-	
Distribution	582	3	19,546	WYP	Situs	-	
Distribution	583	3	83,486	CA	Situs	-	
Distribution	583	3	32,722	ID	Situs	-	
Distribution	583	3	127,838	OR	Situs	127,838	
Distribution	583	3	278,478	UT	Situs	-	
Distribution	583	3	19,159	WA	Situs	-	
Distribution	583	3	59,238	WYP	Situs	-	
Distribution	583	3	5,229	WYU	Situs	-	
Distribution	585	3	16,698	SNPD	25.578%	4,271	
Distribution	586	3	8,615	CA	Situs	-	
Distribution	586	3	10,350	ID	Situs	-	
Distribution	586	3	70,964	OR	Situs	70,964	
Distribution	586	3	549	SNPD	25.578%	140	
Distribution	586	3	60,603	UT	Situs	-	
Distribution	586	3	15,214	WA	Situs	-	
Distribution	586	3	18,661	WYP	Situs	-	
Distribution	586	3	4,023	WYU	Situs	-	
Distribution	587	3	38,588	CA	Situs	-	
Distribution	587	3	48,576	ID	Situs	-	
Distribution	587	3	329,096	OR	Situs	329,096	
Distribution	587	3	313,646	UT	Situs	-	
Distribution	587	3	74,465	WA	Situs	-	
Distribution	587	3	72,697	WYP	Situs	-	
Distribution	587	3	5,607	WYU	Situs	-	
			4,952,339			1,410,148	

Description of Adjustment:

This adjustment recognizes wage and benefit increases that have occurred during the base period 12 months ended June 2025, or are projected to occur during the twelve month period ending December 2027 for labor charged to operation & maintenance accounts. See page 4.2.5 for more information on how this adjustment was calculated.

PacifiCorp PAGE 4.2.2
Oregon General Rate Case - December 2027
Wage and Employee Benefits Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Distribution	588	3	200	CA	Situs	-	
Distribution	588	3	205	ID	Situs	-	
Distribution	588	3	7,559	OR	Situs	7,559	
Distribution	588	3	1,564,532	SNPD	25.578%	400,177	
Distribution	588	3	19,749	UT	Situs	-	
Distribution	588	3	1,179	WA	Situs	-	
Distribution	588	3	1,076	WYP	Situs	-	
Distribution	588	3	18	WYU	Situs	-	
Distribution	589	3	1,016	CA	Situs	-	
Distribution	589	3	1,124	ID	Situs	-	
Distribution	589	3	4,598	OR	Situs	4,598	
Distribution	589	3	19,916	UT	Situs	-	
Distribution	589	3	590	WA	Situs	-	
Distribution	589	3	3,605	WYP	Situs	-	
Distribution	589	3	822	WYU	Situs	-	
Distribution	590	3	7,558	CA	Situs	-	
Distribution	590	3	603	ID	Situs	-	
Distribution	590	3	72,411	OR	Situs	72,411	
Distribution	590	3	233,504	SNPD	25.578%	59,726	
Distribution	590	3	49,495	UT	Situs	-	
Distribution	590	3	11,369	WA	Situs	-	
Distribution	590	3	30,316	WYP	Situs	-	
Distribution	591	3	55	SNPD	25.578%	14	
Distribution	592	3	24,552	CA	Situs	-	
Distribution	592	3	25,249	ID	Situs	-	
Distribution	592	3	208,427	OR	Situs	208,427	
Distribution	592	3	84,876	SNPD	25.578%	21,710	
Distribution	592	3	127,975	UT	Situs	-	
Distribution	592	3	41,809	WA	Situs	-	
Distribution	592	3	41,368	WYP	Situs	-	
Distribution	593	3	320,467	CA	Situs	-	
Distribution	593	3	232,614	ID	Situs	-	
Distribution	593	3	1,876,757	OR	Situs	1,876,757	
Distribution	593	3	189,338	SNPD	25.578%	48,429	
Distribution	593	3	1,393,779	UT	Situs	-	
Distribution	593	3	315,128	WA	Situs	-	
Distribution	593	3	368,470	WYP	Situs	-	
Distribution	593	3	49,642	WYU	Situs	-	
Distribution	594	3	40,167	CA	Situs	-	
Distribution	594	3	39,416	ID	Situs	-	
Distribution	594	3	316,935	OR	Situs	316,935	
Distribution	594	3	266	SNPD	25.578%	68	
Distribution	594	3	543,709	UT	Situs	-	
Distribution	594	3	73,618	WA	Situs	-	
Distribution	594	3	39,226	WYP	Situs	-	
			8,385,291			3,016,812	

Description of Adjustment:

This adjustment recognizes wage and benefit increases that have occurred during the base period 12 months ended June 2025, or are projected to occur during the twelve month period ending December 2027 for labor charged to operation & maintenance accounts. See page 4.2.5 for more information on how this adjustment was calculated.

PacifiCorp PAGE 4.2.3
Oregon General Rate Case - December 2027
Wage and Employee Benefits Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Distribution	594	3	9,262	WYU	Situs	-	
Distribution	595	3	46,207	SNPD	25.578%	11,819	
Distribution	596	3	2,696	CA	Situs	-	
Distribution	596	3	2,477	ID	Situs	-	
Distribution	596	3	33,996	OR	Situs	33,996	
Distribution	596	3	7,600	UT	Situs	-	
Distribution	596	3	2,354	WA	Situs	-	
Distribution	596	3	13,198	WYP	Situs	-	
Distribution	596	3	2,925	WYU	Situs	-	
Distribution	597	3	1,042	CA	Situs	-	
Distribution	597	3	869	ID	Situs	-	
Distribution	597	3	10,062	OR	Situs	10,062	
Distribution	597	3	(9,799)	SNPD	25.578%	(2,506)	
Distribution	597	3	8,957	UT	Situs	-	
Distribution	597	3	9,006	WA	Situs	-	
Distribution	597	3	1,153	WYP	Situs	-	
Distribution	597	3	1,499	WYU	Situs	-	
Distribution	598	3	1,349	OR	Situs	1,349	
Distribution	598	3	94,118	SNPD	25.578%	24,074	
Distribution	598	3	10	UT	Situs	-	
Distribution	598	3	461	WA	Situs	-	
Customer Accounts	901	3	1,056,462	CN	30.140%	318,415	
Customer Accounts	902	3	20,370	CA	Situs	-	
Customer Accounts	902	3	58,452	CN	30.140%	17,617	
Customer Accounts	902	3	7,392	ID	Situs	-	
Customer Accounts	902	3	80,515	OR	Situs	80,515	
Customer Accounts	902	3	105,563	UT	Situs	-	
Customer Accounts	902	3	46,838	WA	Situs	-	
Customer Accounts	902	3	62,127	WYP	Situs	-	
Customer Accounts	902	3	13,275	WYU	Situs	-	
Customer Accounts	903	3	3,962	CA	Situs	-	
Customer Accounts	903	3	963,978	CN	30.140%	290,541	
Customer Service	903	3	5,965	ID	Situs	-	
Customer Service	903	3	29,389	OR	Situs	29,389	
Customer Service	903	3	162,623	UT	Situs	-	
Customer Service	903	3	34,699	WA	Situs	-	
Customer Service	903	3	16,046	WYP	Situs	-	
Customer Service	903	3	2,966	WYU	Situs	-	
Customer Service	908	3	11,274	CA	Situs	-	
Customer Service	908	3	201,357	CN	30.140%	60,689	
Customer Service	908	3	1,775	ID	Situs	-	
Customer Service	908	3	115,541	OR	Situs	115,541	
Customer Service	908	3	488	OTHER	0.000%	-	
Customer Service	908	3	165,215	UT	Situs	-	
Customer Service	908	3	23,845	WA	Situs	-	
			3,429,558			991,500	

Description of Adjustment:

This adjustment recognizes wage and benefit increases that have occurred during the base period 12 months ended June 2025, or are projected to occur during the twelve month period ending December 2027 for labor charged to operation & maintenance accounts. See page 4.2.5 for more information on how this adjustment was calculated.

PacifiCorp PAGE 4.2.4
Oregon General Rate Case - December 2027
Wage and Employee Benefits Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Customer Service	908	3	55,085	WYP	Situs	-	
Customer Service	909	3	143,051	CN	30.140%	43,115	
Customer Service	909	3	48	OR	Situs	48	
Customer Service	910	3	5,112	CN	30.140%	1,541	
Administrative & General	920	3	500	CA	Situs	-	
Administrative & General	920	3	14,074	OR	Situs	14,074	
Administrative & General	920	3	5,382,836	SO	27.909%	1,502,290	
Administrative & General	920	3	0	UT	Situs	-	
Administrative & General	920	3	3,280	WYP	Situs	-	
Administrative & General	921	3	2,334	SO	27.909%	651	
Administrative & General	922	3	(1,353,781)	SO	27.909%	(377,825)	
Administrative & General	928	3	15	CA	Situs	-	
Administrative & General	928	3	6,596	ID	Situs	-	
Administrative & General	928	3	10,668	OR	Situs	10,668	
Administrative & General	928	3	15,782	SO	27.909%	4,405	
Administrative & General	928	3	17,302	UT	Situs	-	
Administrative & General	928	3	2,555	WA	Situs	-	
Administrative & General	928	3	9,940	WYP	Situs	-	
Administrative & General	929	3	(2,261,101)	SO	27.909%	(631,048)	
Administrative & General	935	3	21	CA	Situs	-	
Administrative & General	935	3	739	OR	Situs	739	
Administrative & General	935	3	130,698	SO	27.909%	36,476	
Administrative & General	935	3	20	WA	Situs	-	
Administrative & General	935	3	54	WYP	Situs	-	
			2,185,828			605,134	
Page 4.2			13,637,958			3,844,623	
Page 4.2.1			4,952,339			1,410,148	
Page 4.2.2			8,385,291			3,016,812	
Page 4.2.2			3,429,558			991,500	
Page 4.2.4			2,185,828			605,134	
			32,590,973			9,868,217	

Description of Adjustment:

This adjustment recognizes wage and benefit increases that have occurred during the base period 12 months ended June 2025, or are projected to occur during the twelve month period ending December 2027 for labor charged to operation & maintenance accounts. See page 4.2.5 for more information on how this adjustment was calculated.

PacifiCorp
Oregon General Rate Case - December 2027
Wage and Employee Benefit Adjustment

The unadjusted, annualized (12 months ended June 2025), and pro forma period (12 months ending December 2027) labor expenses are summarized on page 4.2.6. The following is an explanation of the procedures used to develop the labor benefits & expenses used in this adjustment.

1. Actual June 2025 total labor related expenses are identified on page 4.2.6, including bare labor, incentive, other labor, pensions, benefits, and payroll taxes.

2. Actual June 2025 expenses for regular time, overtime, and premium pay were identified by labor group and annualized to reflect wage increases during the base period. These annualizations can be found on page 4.2.7.

3. The annualized June 2025 regular time, overtime, and premium pay expenses were then escalated prospectively by labor group to December 2027 (see page 4.2.8). Union and non-union costs were escalated using the contractual and target rates found on page 4.2.8.

4. Compensation related to the Annual Incentive Plan (AIP) is included on a 5-year historical average, using a ratio of AIP to wages, as adopted in Settlement and approved in UE-399. Named Executive Officers (NEO's) and one-half of remaining AIP has also been removed per Commission order in general rate case UE-374.

The Annual Incentive Plan is the second step of a two-stage compensation philosophy that provides certain employees with market average compensation with a portion at risk and based on achieving annual goals. Union employees do not participate in the Company's Annual Incentive Plan; instead, they receive annual increases to their wages that are reflected in the escalation described above. described above. Bonuses are also included on a 5-year historical average, reflecting a 50 percent exclusion in accordance with treatment adopted in the final order in UE-433.

5. Pro Forma December 2027 pension and employee benefit expenses are based on either actuarial projections or are calculated by using actual June 2025 data escalated to December 2027. These expenses can be found on page 4.2.10.

6. Payroll tax calculations can be found on page 4.2.11.

PacifiCorp
Oregon General Rate Case - December 2027
Wage and Employee Benefit Adjustment

Description	Actual 12 Months Ended June 2025	Pro Forma 12 Months Ended December 2027	Adjustment	Ref.
Regular Ordinary Time	530,920,670	574,821,245	43,900,575	
Overtime	95,280,751	103,159,291	7,878,540	
Premium Pay	13,048,774	14,127,746	1,078,972	
Subtotal for Escalation	**639,250,195**	**692,108,282**	**52,858,087**	4.2.7&8
Unused Leave	6,101,804	6,606,347	504,544	4.2.9
Temporary/Contract Labor	-	-	-	
Severance Pay	347,284	347,284	-	4.2.9
Other Salary/Labor Costs	6,627,493	6,627,493	-	
Joint Owner Cutbacks	(1,186,016)	(1,284,085)	(98,069)	4.2.9
Subtotal Bare Labor	**651,140,759**	**704,405,321**	**53,264,562**	
Annual Incentive Plan	28,930,642	18,369,145	(10,561,497)	4.2.9
Total Incentive	**28,930,642**	**18,369,145**	**(10,561,497)**	
Overtime Meals	1,856,975	1,856,975	-	
Bonus and Awards	1,452,443	646,004	(806,439)	4.2.9
Physical Exam	77,999	77,999	-	
Education Assistance	173,717	173,717	-	
Mining Salary/Benefit Credit	(190,598)	(190,598)	-	
Total Other Labor	**3,370,537**	**2,564,098**	**(806,439)**	
Subtotal Labor and Incentive	**683,441,938**	**725,338,564**	**41,896,627**	
Pensions	4,623,176	3,249,276	(1,373,900)	4.2.10
SERP Plan	-	-	-	4.2.10
Post Retirement Benefits	2,018,062	1,081,002	(937,059)	4.2.10
Post Employment Benefits	4,859,295	1,854,945	(3,004,349)	4.2.10
Total Pensions	**11,500,532**	**6,185,224**	**(5,315,308)**	4.2.10
Pension Administration	297,116	278,965	(18,151)	4.2.10
Medical	69,764,415	76,392,035	6,627,619	4.2.10
Dental	3,896,237	4,048,191	151,953	4.2.10
Vision	419,177	419,177	0	4.2.10
Life	299,920	324,720	24,800	4.2.10
401(k)	54,969,694	59,515,008	4,545,314	4.2.10
401(k) Administration	585	-	(585)	4.2.10
Accidental Death & Disability	28,127	30,453	2,326	4.2.10
Long-Term Disability	4,256,463	4,608,420	351,957	4.2.10
Worker's Compensation	1,904,499	2,061,977	157,479	4.2.10
Other Salary Overhead	2,241,506	2,241,506	-	4.2.10
Total Benefits	**138,077,738**	**149,920,450**	**11,842,712**	4.2.10
Subtotal Pensions and Benefits	**149,578,270**	**156,105,674**	**6,527,404**	4.2.10
Payroll Tax Expense	47,452,603	50,520,746	3,068,143	4.2.11
Payroll Tax Expense-Unemployment	4,687,587	4,687,587	-	
Total Payroll Taxes	**52,140,189**	**55,208,333**	**3,068,143**	
Total Labor	**885,160,397**	**936,652,571**	**51,492,174**	4.2.14
Non-Utility and Capitalized Labor	324,915,286	343,816,487	18,901,201	4.2.14
Total Utility Labor	**560,245,111**	**592,836,084**	**32,590,973**	4.2.14
			Ref. 4.2.4	

PacifiCorp
Oregon General Rate Case - December 2027
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Labor (12 Months Ended June 2025)

Account Desc.	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Total	
Regular Ordinary Time	44,252	42,436	41,113	45,674	41,562	43,337	47,783	43,024	43,917	46,259	46,665	44,899	530,921	**Ref. 4.2.6**
Overtime	11,052	8,249	6,740	8,657	7,850	8,359	7,399	8,499	7,577	6,392	7,051	7,457	95,281	**Ref. 4.2.6**
Premium Pay	1,627	1,648	1,015	1,318	1,120	933	788	861	936	754	1,036	1,012	13,049	**Ref. 4.2.6**
Grand Total	**56,932**	**52,333**	**48,867**	**55,649**	**50,532**	**52,629**	**55,970**	**52,385**	**52,429**	**53,404**	**54,753**	**53,368**	**639,250**	**Ref. 4.2.6**

Labor (12 Months Ended June 2025)

Group Code	Labor Group	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Total
2	Officer/Exempt	20,454	20,026	18,300	21,360	19,607	20,006	23,588	20,559	21,928	21,911	23,501	21,607	252,847
3	IBEW 125	5,257	4,825	4,320	5,089	4,520	4,334	4,558	4,500	4,397	4,295	4,512	4,519	55,125
4	IBEW 659	7,187	4,673	4,508	5,454	5,435	5,354	5,048	6,282	4,999	4,612	4,894	5,138	63,584
5	UWUA 197	303	201	205	270	310	372	262	255	292	227	221	225	3,144
8	UWUA 127	4,584	4,240	4,409	4,673	4,306	4,954	4,698	4,297	4,378	4,818	4,218	4,548	54,124
9	IBEW 57 WY	92	91	84	119	79	84	83	80	75	94	87	84	1,051
11	IBEW 57 PD	12,694	12,181	11,073	12,399	10,358	11,009	11,240	10,671	10,340	10,870	10,880	11,515	135,229
12	IBEW 57 PS	3,977	3,808	3,804	3,965	3,696	4,127	4,049	3,573	3,727	4,051	3,939	3,877	46,594
13	PCCC Non-Exempt	517	491	478	462	436	473	510	456	462	462	462	496	5,705
15	IBEW 57 CT	380	361	372	391	413	429	397	344	369	586	512	449	5,002
16	IBEW 77	131	135	134	125	125	176	157	136	155	165	147	146	1,731
18	Non-Exempt	1,356	1,301	1,182	1,342	1,246	1,312	1,380	1,234	1,307	1,314	1,380	764	15,116
Grand Total		**56,932**	**52,333**	**48,867**	**55,649**	**50,532**	**52,629**	**55,971**	**52,385**	**52,429**	**53,404**	**54,753**	**53,368**	**639,252**

Annualization Increase

Group Code	Labor Group	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	
2	Officer/Exempt							10.95%						(1)
3	IBEW 125								2.50%					(1)
4	IBEW 659											4.00%		(1)
5	UWUA 197												2.50%	(1)
8	UWUA 127				5.50%									(1)
9	IBEW 57 WY	4.50%												(1)
11	IBEW 57 PD								2.50%					(1)
12	IBEW 57 PS								2.50%					(1)
13	PCCC Non-Exempt							10.95%						(1)
15	IBEW 57 CT								2.50%					(1)
16	IBEW 77		3.00%						3.00%					(1)
18	Non-Exempt							10.95%						(1)

Annualized Labor June 2025

Group Code	Labor Group	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Total	
2	Officer/Exempt	22,694	22,219	20,304	23,699	21,754	22,196	23,588	20,559	21,928	21,911	23,501	21,607	265,960	
3	IBEW 125	5,388	4,946	4,428	5,216	4,633	4,442	4,671	4,500	4,397	4,295	4,512	4,519	55,948	
4	IBEW 659	7,475	4,860	4,688	5,672	5,653	5,568	5,250	6,533	5,199	4,796	4,894	5,138	65,726	
5	UWUA 197	310	206	210	277	318	382	269	261	300	233	227	225	3,217	
8	UWUA 127	4,837	4,473	4,652	4,673	4,306	4,954	4,698	4,297	4,378	4,818	4,218	4,548	54,852	
9	IBEW 57 WY	92	91	84	119	79	84	83	80	75	94	87	84	1,051	
11	IBEW 57 PD	13,011	12,486	11,350	12,709	10,617	11,284	11,521	10,671	10,340	10,870	10,880	11,515	137,253	
12	IBEW 57 PS	4,077	3,903	3,899	4,064	3,789	4,230	4,151	3,573	3,727	4,051	3,939	3,877	47,280	
13	PCCC Non-Exempt	573	545	530	512	484	525	510	456	462	462	462	496	6,018	
15	IBEW 57 CT	390	370	381	400	423	440	407	344	369	586	512	449	5,071	
16	IBEW 77	138	139	138	129	129	181	161	136	155	165	147	146	1,764	
18	Non-Exempt	1,505	1,443	1,311	1,489	1,382	1,455	1,380	1,234	1,307	1,314	1,380	764	15,963	
Grand Total		**60,489**	**55,681**	**51,974**	**58,960**	**53,567**	**55,742**	**56,690**	**52,642**	**52,636**	**53,594**	**54,759**	**53,368**	**660,102**	**Ref. 4.2.6**

PacifiCorp
Oregon General Rate Case - December 2027
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Pro Forma Increase to December 2027
Increases occur on the 26th of each month. For this exhibit, each increase is listed on the first day of the following month. For example, an increase that occurs on December 26, 2025 is shown as effective on January 1, 2026.

Group Code	Labor Group	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2	Officer/Exempt													
	12/26/2025	2.50%												(3)
	12/26/2026	3.50%												(3)
3	IBEW 125													
	1/26/2026		2.50%											(2)
4	IBEW 659													
	4/26/2026					3.75%								(2)
	4/26/2027					4.00%								(2)
5	UWUA 197													
	5/26/2026						2.50%							(2)
	5/26/2027						2.50%							(2)
8	UWUA 127													
	9/26/2026										3.50%			(2)
	9/26/2027										3.00%			(2)
9	IBEW 57 WY													
	6/26/2026							2.50%						(2)
	6/26/2027							2.50%						(2)
11	IBEW 57 PD													
	1/26/2026		2.50%											(2)
	1/26/2027		2.50%											(2)
12	IBEW 57 PS													
	1/26/2026		2.50%											(2)
	1/26/2027		2.50%											(2)
13	PCCC Non-Exempt													
	12/26/2025	2.50%												(3)
	12/26/2026	3.50%												(3)
15	IBEW 57 CT													
	1/26/2026		2.50%											(2)
	1/26/2027		2.50%											(2)
16	IBEW 77													
	1/26/2026		2.50%											(2)
	1/26/2027		2.50%											(2)
18	Non-Exempt													
	12/26/2025	2.50%												(3)
	12/26/2026	3.50%												(3)

Pro Forma Labor December 2027

Group Code	Labor Group	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
2	Officer/Exempt	24,075	23,571	21,540	25,142	23,079	23,548	25,024	21,810	23,262	23,245	24,932	22,922	282,150	
3	IBEW 125	5,388	5,070	4,539	5,347	4,749	4,553	4,788	4,612	4,507	4,402	4,625	4,632	57,212	
4	IBEW 659	7,475	4,860	4,688	5,672	6,099	6,008	5,665	7,049	5,609	5,175	5,281	5,544	69,125	
5	UWUA 197	310	206	210	277	318	401	283	274	315	245	238	237	3,313	
8	UWUA 127	4,837	4,473	4,652	4,673	4,306	4,954	4,698	4,297	4,378	5,136	4,496	4,848	55,749	
9	IBEW 57 WY	92	91	84	119	79	84	87	84	79	98	92	88	1,076	
11	IBEW 57 PD	13,011	13,118	11,924	13,353	11,154	11,856	12,104	11,212	10,863	11,420	11,431	12,098	143,543	
12	IBEW 57 PS	4,077	4,101	4,096	4,269	3,981	4,444	4,361	3,753	3,916	4,257	4,139	4,073	49,467	
13	PCCC Non-Exempt	608	578	563	543	513	557	541	484	490	490	490	526	6,384	
15	IBEW 57 CT	390	389	400	421	445	462	428	361	387	616	538	471	5,308	
16	IBEW 77	138	146	145	135	135	191	169	142	163	174	155	154	1,847	
18	Non-Exempt	1,596	1,531	1,391	1,580	1,466	1,544	1,464	1,309	1,387	1,394	1,464	810	16,935	
Grand Total		**61,997**	**58,133**	**54,231**	**61,531**	**56,324**	**58,600**	**59,613**	**55,388**	**55,357**	**56,650**	**57,879**	**56,404**	**692,108**	**Ref. 4.2.6**

(1) Overall actual.
(2) Labor increases supported by union contracts/actual increases
(3) Projected labor increases supported by planned targets

PacifiCorp
Oregon General Rate Case - December 2027
Wage and Employee Benefit Adjustment

Composite Labor Increases

			Ref.
Regular Time/Overtime/Premium Pay Annualize - Actual	639,250,195		4.2.6
Regular Time/Overtime/Premium Pay December 2027 - Pro Forma	692,108,282	CAGR[1]	
% Increase-Total	8.27%	4.05%	

Miscellaneous Bare Labor Escalation

Description	June 2025 Actual	Pro Forma Increase	December 2027 Pro Forma	Pro Forma Adjustment	Ref.
Unused Leave	6,101,804	8.27%	6,606,347	504,544	4.2.6
Joint Owner Cutbacks	(1,186,016)	8.27%	(1,284,085)	(98,069)	4.2.6
	4,915,788		5,322,263	406,475	

Bonus and Awards Calculation:

Description	June 2025 Actual	December 2027	[2] Remove 50%	Pro Forma Adjustment	Ref.
Bonus and Awards Calculation	1,452,443	1,292,008	646,004	(806,439)	

Year	[3] Exempt Bonus	Non-Exempt and Union Bonus	Total	
2024	456,133	84,168	540,301	
2023	1,685,409	692,413	2,377,822	
2022	1,288,716	419,961	1,708,677	
2021	41,767	141,126	182,893	
2020	660,585	989,763	1,650,348	
	4,132,610	2,327,430	6,460,040	Total
	826,522	465,486	**1,292,008**	5-Year Avg.
			Above	

Annual Incentive Plan Escalation

Description	June 2025 Actual	December 2027	[3] Remove 50%	Pro Forma Adjustment	Ref.
Annual Incentive Plan Compensation	28,930,642	36,738,290	18,369,145	(10,561,497)	4.2.6

Year	*[4] Exempt Wages*	*[3] AIP*	*%*
2024	232,396,348	19,901,900	8.56%
2023	215,714,914	25,603,828	11.87%
2022	193,734,722	31,894,180	16.46%
2021	188,363,246	28,389,339	15.07%
2020	196,651,699	27,916,645	14.20%
5-Year Total	1,026,860,928	133,705,892	13.02%
2027	**282,149,982**	**36,738,290**	13.02%

[1] Compound Annual Growth Rate
[2] Per Commission Order in GRC UE-433, Order No. 24-447
[3] Per Commission Order in GRC UE-374, Order No. 20-473
[4] Net of Named Executive Officers (NEO's) Compensation

PacifiCorp
Oregon General Rate Case - December 2027
Wage and Employee Benefit Adjustment

	A	B	C	D	D - A	
Description	**Actual June 2025 Net of Joint Venture**	**Actual June 2025 Gross**	**Projected December 2027 Gross**	**Projected December 2027 Net of Joint Venture**	**Pro Forma Adjustment**	**Ref**
Pensions	4,623,176	4,695,347	3,300,000	3,249,276	**(1,373,900)**	4.2.6
SERP Plan	-	-	-	-	**-**	4.2.6
Post Retirement Benefits	2,018,062	2,041,058	1,093,321	1,081,002	**(937,059)**	4.2.6
Post Employment Benefits	4,859,295	4,989,864	1,904,788	1,854,945	**(3,004,349)**	4.2.6
Subtotal	11,500,532	11,726,270	6,298,109	6,185,224	**(5,315,308)**	4.2.6
Pension Administration	297,116	316,447	297,116	278,965	**(18,151)**	4.2.6
Medical	69,764,415	71,662,486	78,470,423	76,392,035	**6,627,619**	4.2.6
Dental	3,896,237	4,002,094	4,158,175	4,048,191	**151,953**	4.2.6
Vision	419,177	430,162	430,162	419,177	**-**	4.2.6
Life	299,920	306,021	331,325	324,720	**24,800**	4.2.6
401(k)	54,969,694	56,192,901	60,839,359	59,515,008	**4,545,314**	4.2.6
401(k) Administration	585	585	-	-	**(585)**	4.2.6
Accidental Death & Disability	28,127	28,182	30,513	30,453	**2,326**	4.2.6
Long-Term Disability	4,256,463	4,370,027	4,731,374	4,608,420	**351,957**	4.2.6
Worker's Compensation	1,904,499	1,956,584	2,118,369	2,061,977	**157,479**	4.2.6
Other Salary Overhead	2,241,506	2,243,428	2,243,428	2,241,506	**-**	4.2.6
Subtotal	138,077,738	141,508,918	153,650,244	149,920,450	**11,842,712**	4.2.6
Grand Total	**149,578,270**	153,235,188	159,948,353	**156,105,674**	**6,527,404**	4.2.6
	Ref. 4.2.6			Ref. 4.2.6	Ref. 4.2.6	

PacifiCorp
Oregon General Rate Case - December 2027
Wage and Employee Benefit Adjustment
Payroll Tax Adjustment Calculation

	Line No.	Ref	Social Security	Medicare	Total FICA Tax	Ref
FICA Calculated on December 2027 Pro Forma Labor						
Pro Forma Wages Adjustment	h		52,858,087	52,858,087		4.2.6
Pro Forma Incentive Adjustment	i		(10,561,497)	(10,561,497)		4.2.6
	j	h + i	42,296,591	42,296,591		
Percentage of eligible wages	k		93.61%	100.00%		
Total eligible wages	l	j * k	39,594,240	42,296,591		
Tax rate	m		6.20%	1.45%		
Tax on eligible wages	n	l * m	2,454,843	613,301		
Total FICA Tax on Pro Forma Labor		n	**2,454,843**	**613,301**	**3,068,143**	4.2.6

PacifiCorp
Oregon General Rate Case - December 2027
Wages and Employee Benefits Adjustment
2020 Protocol FERC Spread

Indicator	Actual 12 Months Ended June 2025	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2027	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2027 Oregon Allocated
500SG	14,697,888	1.660%	855,016	15,552,904	27.756%	237,315	4,316,798
502SG	23,986,017	2.710%	1,395,331	25,381,349	27.756%	387,282	7,044,739
503SE	134,479	0.015%	7,823	142,302	26.823%	2,098	38,169
505SG	15,301	0.002%	890	16,192	27.756%	247	4,494
506SG	30,220,419	3.414%	1,758,003	31,978,423	27.756%	487,944	8,875,795
510SG	3,019,857	0.341%	175,673	3,195,530	27.756%	48,759	886,938
511SG	6,547,743	0.740%	380,900	6,928,642	27.756%	105,721	1,923,085
512SG	26,212,774	2.961%	1,524,868	27,737,642	27.756%	423,236	7,698,742
513SG	13,003,912	1.469%	756,473	13,760,385	27.756%	209,963	3,819,274
514SG	2,640,894	0.298%	153,628	2,794,522	27.756%	42,640	775,636
535SG-P	4,766,633	0.539%	277,288	5,043,921	27.756%	76,963	1,399,969
535SG-U	12,260,174	1.385%	713,207	12,973,382	27.756%	197,955	3,600,837
536SG-P	50,208	0.006%	2,921	53,129	27.756%	811	14,746
537SG-P	878,955	0.099%	51,131	930,086	27.756%	14,192	258,151
537SG-U	32,115	0.004%	1,868	33,984	27.756%	519	9,432
539SG-P	5,743,766	0.649%	334,130	6,077,897	27.756%	92,740	1,686,955
539SG-U	6,454,774	0.729%	375,492	6,830,266	27.756%	104,220	1,895,779
540SG-P	874	0.000%	51	925	27.756%	14	257
542SG-P	273,643	0.031%	15,919	289,562	27.756%	4,418	80,370
542SG-U	16,759	0.002%	975	17,734	27.756%	271	4,922
543SG-P	271,477	0.031%	15,793	287,269	27.756%	4,383	79,733
543SG-U	195,568	0.022%	11,377	206,945	27.756%	3,158	57,439
544SG-P	782,708	0.088%	45,532	828,240	27.756%	12,638	229,883
544SG-U	211,367	0.024%	12,296	223,663	27.756%	3,413	62,079
545SG-P	838,761	0.095%	48,793	887,554	27.756%	13,543	246,346
545SG-U	64,623	0.007%	3,759	68,382	27.756%	1,043	18,980
546SG	29,298	0.003%	1,704	31,002	27.756%	473	8,605
548SG	6,649,738	0.751%	386,833	7,036,571	27.756%	107,368	1,953,041
549OR	17,084	0.002%	994	18,078	100.000%	994	18,078
549SG	3,299,456	0.373%	191,938	3,491,395	27.756%	53,274	969,057
552SG	1,157,934	0.131%	67,360	1,225,295	27.756%	18,696	340,088
553SG	2,382,099	0.269%	138,573	2,520,672	27.756%	38,462	699,627
554SG	95,644	0.011%	5,564	101,208	27.756%	1,544	28,091
556SG	713,699	0.081%	41,518	755,217	27.756%	11,524	209,615
557ID	43,293	0.005%	2,518	45,811	0.000%	-	-
557OR	310	0.000%	18	328	100.000%	18	328
557SE	-	0.000%	-	-	26.823%	-	-
557SG	37,594,327	4.247%	2,186,964	39,781,290	27.756%	607,004	11,041,526
558WPSG	11,457	0.001%	667	12,124	27.756%	185	3,365
558XPOR	1,412,700	0.160%	82,181	1,494,880	100.000%	82,181	1,494,880
559SG	413,824	0.047%	24,073	437,897	27.756%	6,682	121,541
560SG	10,588,777	1.196%	615,978	11,204,755	27.756%	170,968	3,109,944
561SG	13,469,348	1.522%	783,548	14,252,896	27.756%	217,478	3,955,973
562SG	2,581,591	0.292%	150,178	2,731,769	27.756%	41,683	758,218
563SG	656,855	0.074%	38,211	695,066	27.756%	10,606	192,920
566SG	106,372	0.012%	6,188	112,560	27.756%	1,718	31,242
567SG	184,960	0.021%	10,760	195,719	27.756%	2,986	54,323
568SG	1,837,453	0.208%	106,890	1,944,342	27.756%	29,668	539,663
569SG	3,509,752	0.397%	204,172	3,713,923	27.756%	56,669	1,030,821
570SG	8,468,380	0.957%	492,629	8,961,009	27.756%	136,732	2,487,180
571SG	4,995,651	0.564%	290,611	5,286,262	27.756%	80,661	1,467,232
572SG	1,329	0.000%	77	1,406	27.756%	21	390
580CA	991,812	0.112%	57,696	1,049,509	0.000%	-	-
580ID	213,891	0.024%	12,443	226,334	0.000%	-	-
580OR	1,430,924	0.162%	83,241	1,514,165	100.000%	83,241	1,514,165
580SNPD	12,992,611	1.468%	755,815	13,748,427	25.578%	193,323	3,516,585
580UT	742,195	0.084%	43,175	785,370	0.000%	-	-
580WA	150,362	0.017%	8,747	159,109	0.000%	-	-
580WYP	168,926	0.019%	9,827	178,753	0.000%	-	-
580WYU	100,319	0.011%	5,836	106,155	0.000%	-	-
581SNPD	17,716,137	2.001%	1,030,596	18,746,733	25.578%	263,607	4,795,056
582CA	73,309	0.008%	4,265	77,573	0.000%	-	-
582ID	121,691	0.014%	7,079	128,770	0.000%	-	-
582OR	502,172	0.057%	29,213	531,384	100.000%	29,213	531,384
582UT	1,295,070	0.146%	75,338	1,370,408	0.000%	-	-
582WA	63,476	0.007%	3,693	67,168	0.000%	-	-
582WYP	335,994	0.038%	19,546	355,540	0.000%	-	-
583CA	1,435,149	0.162%	83,486	1,518,635	0.000%	-	-
583ID	562,494	0.064%	32,722	595,215	0.000%	-	-
583OR	2,197,559	0.248%	127,838	2,325,397	100.000%	127,838	2,325,397
583UT	4,787,083	0.541%	278,478	5,065,560	0.000%	-	-
583WA	329,350	0.037%	19,159	348,509	0.000%	-	-
583WYP	1,018,316	0.115%	59,238	1,077,554	0.000%	-	-
583WYU	89,884	0.010%	5,229	95,113	0.000%	-	-
585SNPD	287,045	0.032%	16,698	303,743	25.578%	4,271	77,692

PacifiCorp
Oregon General Rate Case - December 2027
Wages and Employee Benefits Adjustment
2020 Protocol FERC Spread

Indicator	Actual 12 Months Ended June 2025	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2027	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2027 Oregon Allocated
586CA	148,099	0.017%	8,615	156,714	0.000%	-	-
586ID	177,925	0.020%	10,350	188,276	0.000%	-	-
586OR	1,219,888	0.138%	70,964	1,290,853	100.000%	70,964	1,290,853
586SNPD	9,431	0.001%	549	9,980	25.578%	140	2,553
586UT	1,041,784	0.118%	60,603	1,102,387	0.000%	-	-
586WA	261,537	0.030%	15,214	276,751	0.000%	-	-
586WYP	320,793	0.036%	18,661	339,455	0.000%	-	-
586WYU	69,158	0.008%	4,023	73,182	0.000%	-	-
587CA	663,340	0.075%	38,588	701,928	0.000%	-	-
587ID	835,033	0.094%	48,576	883,610	0.000%	-	-
587OR	5,657,228	0.639%	329,096	5,986,325	100.000%	329,096	5,986,325
587UT	5,391,642	0.609%	313,646	5,705,288	0.000%	-	-
587WA	1,280,067	0.145%	74,465	1,354,532	0.000%	-	-
587WYP	1,249,676	0.141%	72,697	1,322,373	0.000%	-	-
587WYU	96,391	0.011%	5,607	101,999	0.000%	-	-
588CA	3,433	0.000%	200	3,632	0.000%	-	-
588ID	3,523	0.000%	205	3,727	0.000%	-	-
588OR	129,946	0.015%	7,559	137,505	100.000%	7,559	137,505
588SNPD	26,894,609	3.038%	1,564,532	28,459,141	25.578%	400,177	7,279,305
588UT	339,483	0.038%	19,749	359,231	0.000%	-	-
588WA	20,263	0.002%	1,179	21,442	0.000%	-	-
588WYP	18,504	0.002%	1,076	19,580	0.000%	-	-
588WYU	304	0.000%	18	322	0.000%	-	-
589CA	17,459	0.002%	1,016	18,474	0.000%	-	-
589ID	19,326	0.002%	1,124	20,451	0.000%	-	-
589OR	79,036	0.009%	4,598	83,634	100.000%	4,598	83,634
589UT	342,361	0.039%	19,916	362,277	0.000%	-	-
589WA	10,138	0.001%	590	10,727	0.000%	-	-
589WYP	61,966	0.007%	3,605	65,571	0.000%	-	-
589WYU	14,133	0.002%	822	14,955	0.000%	-	-
590CA	129,923	0.015%	7,558	137,481	0.000%	-	-
590ID	10,373	0.001%	603	10,976	0.000%	-	-
590OR	1,244,761	0.141%	72,411	1,317,172	100.000%	72,411	1,317,172
590SNPD	4,013,975	0.453%	233,504	4,247,479	25.578%	59,726	1,086,424
590UT	850,836	0.096%	49,495	900,332	0.000%	-	-
590WA	195,438	0.022%	11,369	206,807	0.000%	-	-
590WYP	521,134	0.059%	30,316	551,450	0.000%	-	-
591SNPD	953	0.000%	55	1,008	25.578%	14	258
592CA	422,052	0.048%	24,552	446,604	0.000%	-	-
592ID	434,042	0.049%	25,249	459,292	0.000%	-	-
592OR	3,582,900	0.405%	208,427	3,791,327	100.000%	208,427	3,791,327
592SNPD	1,459,028	0.165%	84,876	1,543,903	25.578%	21,710	394,901
592UT	2,199,912	0.249%	127,975	2,327,886	0.000%	-	-
592WA	718,704	0.081%	41,809	760,513	0.000%	-	-
592WYP	711,126	0.080%	41,368	752,494	0.000%	-	-
593CA	5,508,894	0.622%	320,467	5,829,361	0.000%	-	-
593ID	3,998,683	0.452%	232,614	4,231,298	0.000%	-	-
593OR	32,261,822	3.645%	1,876,757	34,138,579	100.000%	1,876,757	34,138,579
593SNPD	3,254,765	0.368%	189,338	3,444,103	25.578%	48,429	880,936
593UT	23,959,336	2.707%	1,393,779	25,353,115	0.000%	-	-
593WA	5,417,108	0.612%	315,128	5,732,236	0.000%	-	-
593WYP	6,334,075	0.716%	368,470	6,702,545	0.000%	-	-
593WYU	853,357	0.096%	49,642	902,999	0.000%	-	-
594CA	690,486	0.078%	40,167	730,654	0.000%	-	-
594ID	677,562	0.077%	39,416	716,978	0.000%	-	-
594OR	5,448,174	0.616%	316,935	5,765,109	100.000%	316,935	5,765,109
594SNPD	4,576	0.001%	266	4,842	25.578%	68	1,239
594UT	9,346,469	1.056%	543,709	9,890,179	0.000%	-	-
594WA	1,265,508	0.143%	73,618	1,339,126	0.000%	-	-
594WYP	674,305	0.076%	39,226	713,531	0.000%	-	-
594WYU	159,210	0.018%	9,262	168,471	0.000%	-	-
595SNPD	794,304	0.090%	46,207	840,511	25.578%	11,819	214,987
596CA	46,342	0.005%	2,696	49,038	0.000%	-	-
596ID	42,578	0.005%	2,477	45,055	0.000%	-	-
596OR	584,396	0.066%	33,996	618,391	100.000%	33,996	618,391
596UT	130,644	0.015%	7,600	138,244	0.000%	-	-
596WA	40,471	0.005%	2,354	42,825	0.000%	-	-
596WYP	226,870	0.026%	13,198	240,068	0.000%	-	-
596WYU	50,285	0.006%	2,925	53,210	0.000%	-	-
597CA	17,918	0.002%	1,042	18,961	0.000%	-	-
597ID	14,933	0.002%	869	15,802	0.000%	-	-
597OR	172,972	0.020%	10,062	183,034	100.000%	10,062	183,034
597SNPD	(168,450)	-0.019%	(9,799)	(178,250)	25.578%	(2,506)	(45,593)
597UT	153,965	0.017%	8,957	162,922	0.000%	-	-
597WA	154,810	0.017%	9,006	163,816	0.000%	-	-

PacifiCorp
Oregon General Rate Case - December 2027
Wages and Employee Benefits Adjustment
2020 Protocol FERC Spread

Indicator	Actual 12 Months Ended June 2025	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2027	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2027 Oregon Allocated
597WYP	19,819	0.002%	1,153	20,972	0.000%	-	-
597WYU	25,761	0.003%	1,499	27,259	0.000%	-	-
598OR	23,182	0.003%	1,349	24,530	100.000%	1,349	24,530
598SNPD	1,617,907	0.183%	94,118	1,712,025	25.578%	24,074	437,903
598UT	172	0.000%	10	182	0.000%	-	-
598WA	7,926	0.001%	461	8,388	0.000%	-	-
901CN	18,160,778	2.052%	1,056,462	19,217,239	30.140%	318,415	5,792,028
902CA	350,158	0.040%	20,370	370,527	0.000%	-	-
902CN	1,004,794	0.114%	58,452	1,063,245	30.140%	17,617	320,459
902ID	127,066	0.014%	7,392	134,458	0.000%	-	-
902OR	1,384,076	0.156%	80,515	1,464,591	100.000%	80,515	1,464,591
902UT	1,814,641	0.205%	105,563	1,920,203	0.000%	-	-
902WA	805,157	0.091%	46,838	851,996	0.000%	-	-
902WYP	1,067,981	0.121%	62,127	1,130,108	0.000%	-	-
902WYU	228,194	0.026%	13,275	241,469	0.000%	-	-
903CA	68,107	0.008%	3,962	72,069	0.000%	-	-
903CN	16,570,975	1.872%	963,978	17,534,954	30.140%	290,541	5,284,991
903ID	102,546	0.012%	5,965	108,511	0.000%	-	-
903OR	505,210	0.057%	29,389	534,599	100.000%	29,389	534,599
903UT	2,795,519	0.316%	162,623	2,958,141	0.000%	-	-
903WA	596,489	0.067%	34,699	631,188	0.000%	-	-
903WYP	275,835	0.031%	16,046	291,881	0.000%	-	-
903WYU	50,993	0.006%	2,966	53,960	0.000%	-	-
908CA	193,798	0.022%	11,274	205,072	0.000%	-	-
908CN	3,461,368	0.391%	201,357	3,662,725	30.140%	60,689	1,103,936
908ID	30,519	0.003%	1,775	32,294	0.000%	-	-
908OR	1,986,177	0.224%	115,541	2,101,718	100.000%	115,541	2,101,718
908OTHER	8,395	0.001%	488	8,884	0.000%	-	-
908UT	2,840,075	0.321%	165,215	3,005,290	0.000%	-	-
908WA	409,895	0.046%	23,845	433,740	0.000%	-	-
908WYP	946,914	0.107%	55,085	1,001,998	0.000%	-	-
909CN	2,459,070	0.278%	143,051	2,602,121	30.140%	43,115	784,273
909OR	833	0.000%	48	881	100.000%	48	881
910CN	87,871	0.010%	5,112	92,983	30.140%	1,541	28,025
920CA	8,602	0.001%	500	9,102	0.000%	-	-
920OR	241,938	0.027%	14,074	256,012	100.000%	14,074	256,012
920SO	92,531,983	10.454%	5,382,836	97,914,818	27.909%	1,502,290	27,326,940
920UT	0	0.000%	0	0	0.000%	-	-
920WYP	56,385	0.006%	3,280	59,665	0.000%	-	-
921SO	40,126	0.005%	2,334	42,460	27.909%	651	11,850
922SO	(23,271,753)	-2.629%	(1,353,781)	(24,625,534)	27.909%	(377,825)	(6,872,714)
928CA	254	0.000%	15	269	0.000%	-	-
928ID	113,383	0.013%	6,596	119,979	0.000%	-	-
928OR	183,389	0.021%	10,668	194,057	100.000%	10,668	194,057
928SO	271,296	0.031%	15,782	287,078	27.909%	4,405	80,120
928UT	297,421	0.034%	17,302	314,722	0.000%	-	-
928WA	43,913	0.005%	2,555	46,468	0.000%	-	-
928WYP	170,879	0.019%	9,940	180,819	0.000%	-	-
929SO	(38,868,769)	-4.391%	(2,261,101)	(41,129,871)	27.909%	(631,048)	(11,478,891)
935CA	365	0.000%	21	386	0.000%	-	-
935OR	12,702	0.001%	739	13,441	100.000%	739	13,441
935SO	2,246,721	0.254%	130,698	2,377,419	27.909%	36,476	663,511
935WA	349	0.000%	20	369	0.000%	-	-
935WYP	936	0.000%	54	991	0.000%	-	-
Utility Labor	**560,245,111**	**63.29%**	**32,590,973**	**592,836,084**		**9,868,217**	**179,504,773**
						Ref 4.2	
Non-Utility/Capital	324,915,286	36.71%	18,901,201	343,816,487			
Total	**885,160,397**	**100.00%**	**51,492,174**	**936,652,571**			
	Ref 4.2.6		**Ref 4.2.6**	**Ref 4.2.6**			

PacifiCorp PAGE 4.3
Oregon General Rate Case - December 2027
Pension Related Non-Service Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Pension Non-Service Expense	926	3	6,043,781	SO	27.909%	1,686,752	4.3.1
Post-Retirement Non-Service Exp.	926	3	2,209,591	SO	27.909%	616,672	4.3.1
SERP Non-Service Expense	926	3	(2,750,355)	SO	27.909%	(767,594)	4.3.1
			5,503,017			1,535,831	

Description of Adjustment:

This adjustment includes the pension and post-retirement non-service expenses at the 2027 forecast level and removing Supplemental Employee Retirement Plan expenses from the actual period.

PacifiCorp PAGE 4.3.1
Oregon General Rate Case - December 2027
Pension Non-Service Expense

Description	GL 554012 Pension Non-Service Expense Actual Twelve Months Ended June 2025	GL 554022 Post-Retirement Non-Service Expense Actual Twelve Months Ended June 2025	GL 554032 SERP Non-Service Expense Actual Twelve Months Ended June 2025	Total Actual	FERC Acct	Factor
Jul-2024	(669,024)	(383,898)	231,233	(821,689)	926	SO
Aug-2024	(669,024)	(383,898)	231,233	(821,689)	926	SO
Sep-2024	(669,024)	(383,898)	231,233	(821,689)	926	SO
Oct-2024	(669,024)	(383,898)	231,233	(821,689)	926	SO
Nov-2024	(669,024)	(383,898)	231,233	(821,689)	926	SO
Dec-2024	(669,024)	(383,898)	231,233	(821,689)	926	SO
Jan-2025	(444,080)	(323,453)	227,159	(540,373)	926	SO
Feb-2025	(444,080)	(323,453)	227,159	(540,373)	926	SO
Mar-2025	(444,080)	(323,453)	227,159	(540,373)	926	SO
Apr-2025	(444,080)	(323,453)	227,159	(540,373)	926	SO
May-2025	(444,080)	(323,453)	227,159	(540,373)	926	SO
Jun-2025	(444,080)	(323,453)	227,159	(540,373)	926	SO
Total Actual	**(6,678,622)**	**(4,244,104)**	**2,750,355**	**(8,172,371)**		

Description	GL 554012 Pension Non-Service Expense Forecasted Twelve Months Ending December 2027	GL 554022 Post-Retirement Non-Service Expense Forecasted Twelve Months Ending December 2027	GL 554032 SERP Non-Service Expense Forecasted Twelve Months Ending December 2027	Total Forecast	FERC Acct	Factor
Jan-2027	(52,903)	(169,543)	-	(222,446)	926	SO
Feb-2027	(52,903)	(169,543)	-	(222,446)	926	SO
Mar-2027	(52,903)	(169,543)	-	(222,446)	926	SO
Apr-2027	(52,903)	(169,543)	-	(222,446)	926	SO
May-2027	(52,903)	(169,543)	-	(222,446)	926	SO
Jun-2027	(52,903)	(169,543)	-	(222,446)	926	SO
Jul-2027	(52,903)	(169,543)	-	(222,446)	926	SO
Aug-2027	(52,903)	(169,543)	-	(222,446)	926	SO
Sep-2027	(52,903)	(169,543)	-	(222,446)	926	SO
Oct-2027	(52,903)	(169,543)	-	(222,446)	926	SO
Nov-2027	(52,903)	(169,543)	-	(222,446)	926	SO
Dec-2027	(52,903)	(169,543)	-	(222,446)	926	SO
Total Forecasted	**(634,841)**	**(2,034,513)**	**-**	**(2,669,353)**		
Incremental Change	**6,043,781**	**2,209,591**	**(2,750,355)**	**5,503,017**		
	Ref 4.3	**Ref 4.3**	**Ref 4.3**	**Ref 4.3**		

PacifiCorp PAGE 4.4
Oregon General Rate Case - December 2027
Remove Non-Recurring Entries

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Klamath Settlement Cost Overrun	545	1	(3,435,915)	SG	27.756%	(953,658)	4.4.1

Description of Adjustment:

This adjustment removes the entry related to the Klamath Settlement Overrun Costs on a normalization basis.

PacifiCorp PAGE 4.4.1
Oregon General Rate Case - December 2027
Remove Non-Recurring Entries

FERC Account	Account Number	Description	Amount	Alloc	REF
5459000	545500	Klamath Settlement Cost Overrun	3,435,915	SG	REF. 4.4

PacifiCorp PAGE 4.5
Oregon General Rate Case - December 2027
Insurance Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Base Pd. Inj & Damage	925	1	(91,152,142)	SO	27.909%	(25,439,552)	4.5.1
Remove Base Pd. Inj & Damage	925	1	(5,087,786)	OR	Situs	(5,087,786)	4.5.1
Adj. Inj & Damage to 3-yr avg.	925	3	2,022,091	OR	Situs	2,022,091	4.5.2
Adjust Legal Fees to 3-year average	925	3	(6,346,393)	SO	27.909%	(1,771,208)	4.5.5
Adjust property damage expense to 3-year average							
Property Insurance - Transmission	924	3	581,176	OR	Situs	581,176	4.5.3
Property Insurance - OR Dist.	924	3	11,086,278	OR	Situs	11,086,278	4.5.3
Property Insurance - Non-T&D	924	3	(192,831)	OR	Situs	(192,831)	4.5.3
Adjust Liability Insurance Premium	925	3	(103,846,277)	SO	27.909%	(28,982,345)	4.5.4
Adjust Liability Insurance Premium	925	3	24,170,942	OR	Situs	24,170,942	4.5.4
Adjust Property Insurance Premium	924	3	18,380,626	OR	Situs	18,380,626	4.5.4
Adjust Property Insurance Premium	924	3	(634,398)	SO	27.909%	(177,053)	4.5.4
Adjustment to Rate Base:							
Remove Injuries & Damages Reserve	2282	3	1,380,942,925	SO	27.909%	385,405,863	4.5.1
Remove Injuries & Damages Reserve	2281	3	2,028,750	SO	27.909%	566,202	4.5.1
Adjustment to Tax:							
Schedule M - Remove I&D	SCHMDT	3	(370,287,987)	SO	27.909%	(103,343,273)	
DIT Expense - Remove I&D	41010	3	(91,041,226)	SO	27.909%	(25,408,597)	
Accumulated Deferred Income Tax Balanc	190	3	(342,344,845)	SO	27.909%	(95,544,651)	

Description of Adjustment:

This adjustment normalizes injuries and damage expense to reflect a three year average of gross expense net of insurance using the cash method which was approved in Docket No. UE-399. Cash payments on significant wildfire events have been excluded from the average. For property damages, in the current rate case, the Company is proposing to modify the annual accrual calculation from the historical 10-year average as currently approved, to using the most recent 3-year time period. The property insurance premiums and liability insurance premiums in the base period have been adjusted to those in the Company's most current renewal. Finally, legal fees recorded in FERC Account 925 are being adjusted to a historical 3-year average level consistent with the ordered outcome in docket UE-433, order no. 24-447.

PacifiCorp
Oregon General Rate Case - December 2027
Insurance Expense
Injuries and Damages in Unadjusted Results

Amount in Unadjusted Results

G/L Account	Account Title	Allocator	Amount	
	Net Base Year Expense	SO	**91,152,142**	
			Ref 4.5	
545052	Inj/Damage Ins Prov - OR	OR	**5,087,786**	
			Ref 4.5	

Injuries & Damages Reserve

			EOP Balance Jun-25	
	Net Base Year Reserve	SO	**(1,382,971,675)**	**Ref 4.5**

PacifiCorp
Oregon General Rate Case - December 2027
Insurance Expense
Provision for Injuries & Damages
3-Year Average Cash Paid

	Cash Paid - Injuries & Damages				Third Party Insurance Claim Proceeds		
	Cash Expense	Amount not Seeking Recovery	3 - Year Avg to Recover		Claim Proceeds	Amount not Seeking Recovery	3 - Year Avg to Recovery
12 Months Ended June 2023	3,377,918	-			-	-	
12 Months Ended June 2024	13,920,584				-		
12 Months Ended June 2025	4,437,486				-		
Average Cash	7,245,329	-	7,245,329	Below	-	-	-
3 Year Average of Cash Paid for Injuries & Damages Reserve			7,245,329	Above			
3 Year Average of Cash Paid for Insurance Recovery			-	Above			
3 Year Normalized Average			7,245,329				
Oregon SO Allocation %			27.909%				
Oregon Allocated Annual Accrual			**2,022,091**				

PacifiCorp
Oregon General Rate Case - December 2027
Insurance Expense
Provision for Property Damages
3-Year Average

	Actual Losses			Escalate to 2027		
	System Transmission Losses	Oregon Distribution Losses	System Non-T&D Losses	End CPI-U Index	% Increase	2027
June 2022				296.311		
July 2022 - June 2023	1,495,577	16,831,317	-	305.109	2.97%	114.951%
July 2023 - June 2024	6,521,375	23,337,078	-	314.175	2.97%	111.637%
July 2024 - June 2025	855,346	21,788,843	-	322.561	2.67%	108.415%
July 2025 - December 2027				340.613	5.60%	105.597%

	Actual Losses Escalated to CY 2027		
	System Transmission Losses	Oregon Distribution Losses	System Non-T&D Losses
July 2022 - June 2023	1,719,184	19,347,810	-
July 2023 - June 2024	7,280,239	26,052,712	-
July 2024 - June 2025	927,325	23,622,400	-
Total in 2027 $	9,926,748	69,022,922	0
3 Year Average	3,308,916	23,007,641	0
Oregon Allocation Factor	SG	Situs	SG
Oregon Allocation %	27.756%	100%	27.756%
June 2025 - Oregon Allocated 3 Year Average	918,409	23,007,641	-
UE - 399 - Oregon Allocated 10 Year Average	279,758	10,443,216	183,838
UE - 433 - Oregon Allocated 10 Year Average	394,707	13,399,509	201,824
Amount in EOP June 2025	337,233	11,921,363	192,831
Adjustment	**581,176**	**11,086,278**	**(192,831)**
	Ref 4.5	**Ref 4.5**	**Ref 4.5**

PacifiCorp
Oregon General Rate Case - December 2027
Insurance Expense
Adjust Base Period Insurance Premium to Expected Level

	Allocation Factor	Premium Renewal 2026/2027	Base Period 12 ME Jun-25	Adjustment	
Excess Liability Insurance Premium - Wildfire & Non-Wildfire	SO	23,311,066	127,157,342	**(103,846,277)**	**Ref 4.5**
Divisional Liability Premiums - Wildfire	OR[1]	24,170,942	-	**24,170,942**	**Ref 4.5**
Divisional 3rd Party Property Premiums - Wildfire	OR[1]	18,380,626	-	**18,380,626**	**Ref 4.5**
Non-T&D Property Insurance Premium	SO	6,035,497	6,669,895	**(634,398)**	**Ref 4.5**

	Total Policy Premium	Jurisdiction	Allocated Premium	
Divisional Liability Insurance Premium - Wildfire	32,875,570	CA	2,625,894	
		OR	**24,170,942**	**Above**
		WA	6,078,734	
Third-party Property Insurance - Wildfire	25,000,000	CA	1,996,843	
		OR	**18,380,626**	**Above**
		WA	4,622,531	

	SO Factor
CA	3.032%
OR	27.909%
WA	7.019%
UT	44.511%
ID	5.377%
WY	12.150%
FERC	0.003%
Total	**100.00%**

1) The situs excess premium is determined by applying the ratio of SO allocation attributable to the states covered under the policy.

PacifiCorp
Oregon General Rate Case - December 2027
Insurance Expense
3-Year Average Legal Fees

	Legal Fees FERC 925	
12 Months Ended June 2023	15,885,414	
12 Months Ended June 2024	32,847,609	
12 Months Ended June 2025	33,886,101	
3-Year Average	27,539,708	
Adjustment	**(6,346,393)**	**Ref 4.5**

PacifiCorp PAGE 4.6
Oregon General Rate Case - December 2027
Generation Overhaul Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Generation Overhaul Expense - Steam	510	1	8,608,045	SG	27.756%	2,389,212	4.6.1
Generation Overhaul Expense - Other	553	1	(2,953,598)	SG	27.756%	(819,788)	4.6.1

Description of Adjustment:

This adjustment normalizes generation overhaul expenses in the 12 months ended June 2025 using a four-year average methodology. In this adjustment, overhaul expenses from July 2021 - June 2025 are restated in constant dollars to a June 2025 level using industry specific indices and then those constant dollars are averaged. The actual overhaul costs for the 12 months ended June 2025 are subtracted from the four-year average which results in this adjustment.

Pacificorp
Oregon General Rate Case - December 2027
Generation Overhaul Expense

FUNCTION: STEAM

Period	Overhaul Expense	Restate to Constant Dollars	Constant Dollars	
12 Months Ended Jun 2022	33,039,668	12.71%	37,239,758	
12 Months Ended Jun 2023	31,372,618	7.21%	33,634,719	
12 Months Ended Jun 2024	36,062,181	3.65%	37,377,732	
12 Months Ended Jun 2025	24,606,676	0.00%	24,606,676	
4 Year Average - Steam			33,214,722	
12 Months Ended Jun 2025 Overhaul Expense - Steam			24,606,676	**Ref. 4.6.2**
Adjustment			**8,608,045**	**Ref. 4.6**

FUNCTION: OTHER

Period	Overhaul Expense	Restate to Constant Dollars (1)	Constant Dollars	
12 Months Ended Jun 2022	6,880,068	12.90%	7,767,913	
12 Months Ended Jun 2023	3,848,989	6.51%	4,099,646	
12 Months Ended Jun 2024	7,911,127	3.71%	8,204,277	
12 Months Ended Jun 2025	10,628,743	0.00%	10,628,743	
4 Year Average			7,675,145	
12 Months Ended Jun 2025 Overhaul Expense - Other			10,628,743	**Ref. 4.6.2**
Adjustment			**(2,953,598)**	**Ref. 4.6**
Total Adjustment			**5,654,447**	**Ref. 4.6**

Pacificorp
Oregon General Rate Case - December 2027
Generation Overhaul Expense

Existing Units	Yr. Ended June 2022	Yr. Ended June 2023	Yr. Ended June 2024	Yr. Ended June 2025	
Steam Production					
Blundell	(12,666)	124,741	164,868	340,338	
Dave Johnston	3,979,758	5,701,845	4,997,206	5,419,207	
Gadsby	129,295	466,658	1,129,462	(104,100)	
Hunter	8,253,973	4,892,131	11,032,083	201,201	
Huntington	97,906	7,861,547	9,808,490	22,287	
Jim Bridger	10,405,550	9,696,888	6,452,456	11,162,438	
Naughton	4,921,994	384,759	10,301	5,520,124	
Wyodak	4,401,453	35,984	304	-	
Cholla	-	-	-	-	
Colstrip	92,842	-	1,730,200	1,982,700	
Craig	135,316	1,936,066	417,322	(8,812)	
Hayden	634,248	272,000	319,489	71,293	
Subtotal - Steam	33,039,668	31,372,618	36,062,181	**24,606,676**	**Ref 4.6.1**
Total Steam Production	33,039,668	31,372,618	36,062,181	24,606,676	
Other Production					
Hermiston	703,300	3,330,569	1,258,340	475,564	
Currant Creek	2,093,766	288,991	121,485	623,880	
Lake Side	748,317	(397,541)	5,963,884	9,170,826	
Gadsby Peakers	-	-	-	-	
Chehalis	3,334,685	626,971	567,418	358,473	
Total - Other Production	6,880,068	3,848,989	7,911,127	**10,628,743**	**Ref 4.6.1**
Grand Total	39,919,736	35,221,607	43,973,308	**35,235,420**	

Pacificorp
Oregon General Rate Case - December 2027
Generation Overhaul Expense

STEAM:	**June 2022**	**June 2023**	**June 2024**	**June 2025**
Percentage Change to Jun 2025	**12.71%**	**7.21%**	**3.65%**	**0.00%**

OTHER:	**June 2022**	**June 2023**	**June 2024**	**June 2025**
Percentage Change to Jun 2025	**12.90%**	**6.51%**	**3.71%**	**0.00%**

PacifiCorp PAGE 4.7
Oregon General Rate Case - December 2027
Revenue Sensitive Items & Uncollectible Accounts

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Uncollectible Expense	904	3	(151,589)	OR	Situs	(151,589)	4.7.1
Other Taxes	408	3	(584,460)	OR	Situs	(584,460)	4.7.1
Reg. Commission Expense	928	3	(87,578)	OR	Situs	(87,578)	4.7.1

Description of Adjustment:

This adjusts the Company's actual June 2025 uncollectible accounts expense to the December 2027 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 in docket UE 374.

PacifiCorp
Oregon General Rate Case - December 2027
Revenue Sensitive Items & Uncollectible Accounts

Unadjusted Revenue	1,817,705,929	
Normalized Revenue	**1,793,378,706**	
Adjustments	(24,327,224)	
Uncollectible Expense in Base Period	11,326,542	
Uncollectible %	0.623%	
Uncollectible Expense	**(151,589)**	**Ref. 4.7**
Franchise Tax %	2.2960%	**Ref. 4.7.2**
Resource Supplier Tax %	0.1065%	**Ref. 4.7.2**
Other Tax Expense	**(584,460)**	**Ref. 4.7**
PUC Fees %	0.3600%	
PUC Fees Expense	**(87,578)**	**Ref. 4.7**

PacifiCorp
Oregon General Rate Case - December 2027
Revenue Sensitive Items & Uncollectible Accounts

Three-Year Average Franchise Tax Rate

	Composite Rate	2023	2024	2025	
Sales to Ultimate Consumers		$ 1,531,220,849	$ 1,725,573,161	$ 1,957,000,000	**(a)**
Franchise Tax Expense		$ 34,510,600	$ 40,254,157	$ 45,040,000	**(b)**
Franchise Tax Factor (2023-2025 **Avg.- Last 3 Years**)	**2.2960%**	2.2538%	2.3328%	2.3015%	**(c) = (b)/(a)**
	Ref. 4.7.1				
	1/3(d) +1/3(e) + 1/3(f)	**(d)**	**(e)**	**(f)**	

Three-Year Average ODOE (Resource Supplier Fees) Rate

	Composite Rate	2023	2024	2025	
Gross Operating Revenue Subject to Assessment		$ 1,366,806,197	$ 1,542,346,336	$ 1,732,055,623	**(a)**
Energy Resourse Supplier Assessment		$ 1,640,167	$ 1,479,460	$ 1,792,346	**(b)**
Oregon Department of Energy Tax Factor (2023-2025 **Avg.- Last 3 Years**)	**0.1065%**	0.1200%	0.0959%	0.1035%	**(c) = (b)/(a)**
	Ref. 4.7.1				
	1/3(d) +1/3(e) + 1/3(f)	**(d)**	**(e)**	**(f)**	

PacifiCorp PAGE 4.8
Oregon General Rate Case - December 2027
Memberships and Subscriptions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Total Memberships and Subscriptions							
	930	1	(2,385,043)	SO	27.909%	(665,639)	
	930	1	-	OR	Situs	-	
Total			(2,385,043)			(665,639)	4.8.1
Add Back 75% of National & Regional Memberships							
Various	930	1	1,513,353	SO	27.909%	422,360	4.8.2
	930	1	450	OR	Situs	450	
Total			1,513,803			422,810	4.8.2

Description of Adjustment:

This adjustment removes expenses in excess of Commission policy allowances as stated in the Commission order UE-94. National and regional trade organizations are recognized at 75%. Per Order No. 24-447 in docket UE 433, memberships in chambers of commerce and other economic development organizations are to be excluded from customer rates. This adjustment removes the portion of membership and subscription fees not allowed in rates.

PacifiCorp
Oregon General Rate Case - December 2027
Memberships and Subscriptions

Account	Factor	Description	Amount	
Remove Total Memberships and Subscriptions in Account 930.2				
930.2	SO	Included in Unadjusted Results	(2,385,043)	
930.2	OR	Included in Unadjusted Results	-	
			(2,385,043)	**Ref 4.8**
Allowed National and Regional Trade Memberships at 75%			**Include 75%**	**Excluded**
930.2	OR	ALBANY AREA CHAMBER OF COMMERCE	-	2,595
930.2	OR	Albany Downtown Association & Park Wise	-	180
930.2	SO	Alltricity Network	22,500	-
930.2	SO	American Clean Power Association	223,800	-
930.2	SO	AMERICAN CONSERVATION COALITION	-	14,920
930.2	SO	AMERICAN COUNCIL ON RENEWABLE ENERGY	44,760	-
930.2	SO	AMERICAN GAS ASSOCIATION	1,571	-
930.2	SO	AMERICANS FOR A CLEAN ENERGY GRID	7,460	-
930.2	OR	Arlington Club	-	8,500
930.2	SO	ASSC OF EDISON ILLUMINATING COMPANIES	14,992	-
930.2	SO	Assoc of Edison Illuminationg Companies	14,247	-
930.2	OR	Astoria Downtown Historic District Association	-	250
930.2	OR	Bend Chamber of Commerce	-	2,375
930.2	SO	BHE - Employee Membership dues	-	5,596
930.2	OR	Cannon Beach Chamber of Commerce	-	335
930.2	SO	Capitol Hill Association	-	7,000
930.2	SO	CEATI INTERNATIONAL INC	32,553	-
930.2	OR	Central Point Chamber of Commerce	-	400
930.2	OR	Clatsop Economic Development Resources	-	5,000
930.2	SO	CLEAN HYDROGEN FUTURE COALITION	2,238	-
930.2	SO	COLUMBIA CORRIDOR ASSN	-	3,150
930.2	OR	Columbia River Maritime Museum	-	500
930.2	SO	COMMITTEE ON INVESTMENT OF EMPLOYEE BENEFIT ASSETS IN	-	1,716
930.2	OR	Cottage Grove Chamber of Commerce	-	1,300
930.2	SO	COUNCIL ON STATE TAXATION	-	2,721
930.2	OR	Creswell Chamber of Commerce	-	250
930.2	SO	Curtiss-Wright Flow Control Serv	19,215	-
930.2	OR	Dallas Area Chamber of Commerce	-	695
930.2	OR	Douglas Timber Operators	600	
930.2	OR	Economic Development for Central Oregon	-	10,000
930.2	SO	Edison Electric Institute	962,439	-
930.2	SO	Energy Systems Integration Group	1,710	
930.2	OR	Grants Pass Josephine County Chamber of Commerce	-	3,400
930.2	SO	GRID FORWARD	4,476	-
930.2	OR	Illinois Valley Chamber, Cave Junction OR	-	500
930.2	SO	INSTITUTE OF CERTIFIED RECORDS MANAGERS	-	62
930.2	OR	Klamath County Chamber of Commerce	-	799
930.2	OR	Klamath County Economic Development Association	-	5,000
930.2	OR	Klamath Falls Downtown Association	-	1,000
930.2	OR	Lake County Chamber of Commerce	-	1,000
930.2	OR	League of Oregon Cities	-	1,000
930.2	OR	Lebanon Area Chamber of Commerce	-	3,035
930.2	OR	Lincoln City Chamber of Commerce	-	515
930.2	OR	Linn Economic Development Group	-	1,500
930.2	OR	Linn-Benton Utilities Coordinating Council	-	125
930.2	OR	Madras-Jefferson County Chamber	-	250
930.2	OR	Monmouth- Independence Chamber of Commerce	-	1,499
930.2	OR	Myrtle Creek-Tri City Area Chamber of Commerce	-	105
930.2	SO	National Defense Information Sharing and Analysis Center (ISAC)	14,920	-
930.2	SO	NATIONAL ENERGY AND UTILITY AFFORDABILITY COALITION	1,492	-
930.2	SO	National Hydropower Association	39,108	-
930.2	SO	National Joint Utilities	13,000	-
930.2	SO	North American Energy	8,000	-
930.2	SO	North American Transmission Forum	126,516	-
930.2	OR	North Santiam Chamber of Commerce	-	1,000
930.2	SO	Northwest Hydroelectric Assn	60	
930.2	SO	Nuclear Energy Institute Inc.	5,103	-
930.2	OR	Oregon Business Council	-	24,500
930.2	OR	Oregon Energy Fund	-	75
930.2	SO	PACIFIC NORTHWEST ECONOMIC REGION	5,968	-
930.2	SO	Pacific Northwest Utilities Conference Committee	119,723	-
930.2	OR	Pendleton Chamber of Commerce	-	980
930.2	OR	Philomath Chamber of Commerce, Philomath OR	-	575
930.2	OR	Pilot Rock Chamber of Commerce	-	50
930.2	OR	Portland Business Alliance	-	39,245
930.2	SO	POWDER RIVER BASIN COAL USERS GROUP	-	1,000
930.2	OR	Prineville Chamber of Commerce	-	2,500
930.2	OR	Redmond Chamber of Commerce	-	2,500
930.2	OR	Redmond Economic Development, Inc.	-	7,500

PacifiCorp
Oregon General Rate Case - December 2027
Memberships and Subscriptions

Account	Factor	Description	Amount	
930.2	SO	RENEWABLE ENERGY WILDLIFE INSTITUTE	31,410	-
930.2	SO	Renewable Energy Wildlife Institute	20,000	-
930.2	OR	Roseburg Area Chamber of Commerce	-	1,250
930.2	OR	Roseburg Rotary International	-	5,400
930.2	OR	Rotary Club of Klamath County	-	380
930.2	OR	Rotary Club of Rogue Valley	-	275
930.2	OR	Rotary Club of Roseburg	-	404
930.2	SO	RTO INSIDER LLC	-	1,800
930.2	OR	Seaside Chamber of Commerce	-	800
930.2	OR	Seaside Downtown Development Association	-	175
930.2	SO	Smart Grid Northwest, DBA Grid Forward	9,101	-
930.2	OR	SOREDI (Southern Oregon Regional Economic Development, Inc.)	-	2,750
930.2	SO	SOUTHWEST CLEAN AIR AGENCY	2,029	-
930.2	OR	Sport Oregon	-	7,500
930.2	OR	Stayton-Sublimity Chamber of Commerce	-	5,000
930.2	OR	Strategic Economic Development Corporation	-	2,600
930.2	OR	Sweet Home Chamber of Commerce	-	1,275
930.2	OR	Takena Kiwanis	-	130
930.2	OR	The Chamber of Medford/Jackson County	-	2,247
930.2	OR	Tri-County Chamber of Commerce	-	295
930.2	OR	Umpqua Economic Development Partnership	-	10,000
930.2	SO	UMS Group	(700)	-
930.2	SO	UTILITY SOLID WASTE ACTIVITIES	65,784	
930.2	OR	Wallowa County Chamber of Commerce, Enterprise OR	-	150
930.2	SO	Western Energy Institute	22,375	-
930.2	SO	Western Interstate Energy Board	145,995	-
930.2	SO	Western LAMPAC	2,000	
930.2	SO	Western Power Trading Forum	30,961	-
930.2	SO	Women's Energy Network	3,000	
			2,018,404	**209,628**

Allowed Memberships and Subscriptions - 75% of amount above

930.2	SO	Included in Adjusted Results	1,513,353	**Ref 4.8**
930.2	OR	Included in Adjusted Results	450	**Ref 4.8**
			1,513,803	

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Oregon General Rate Case - December 2027
Meals & Entertainment Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Disallowance Removal	500	1	(11,816)	SG	27.756%	(3,280)	
	502	1	(2,916)	SG	27.756%	(809)	
	503	1	(11)	SE	26.823%	(3)	
	506	1	(55,431)	SG	27.756%	(15,385)	
	511	1	(4,305)	SG	27.756%	(1,195)	
	512	1	(522)	SG	27.756%	(145)	
	513	1	(8,353)	SG	27.756%	(2,319)	
	514	1	(8,952)	SG	27.756%	(2,485)	
	535	1	(1,168)	SG-P	27.756%	(324)	
	535	1	(7,283)	SG-U	27.756%	(2,021)	
	536	1	(179)	SG-P	27.756%	(50)	
	537	1	(2,786)	SG-P	27.756%	(773)	
	537	1	(116)	SG-U	27.756%	(32)	
	539	1	(17,326)	SG-P	27.756%	(4,809)	
	539	1	(16,115)	SG-U	27.756%	(4,473)	
	543	1	(429)	SG-P	27.756%	(119)	
	544	1	(143)	SG-P	27.756%	(40)	
	544	1	(305)	SG-U	27.756%	(85)	
	545	1	(282)	SG-U	27.756%	(78)	
	546	1	(1,399)	SG	27.756%	(388)	
	548	1	(2,646)	SG	27.756%	(734)	
	549	1	(10)	OR	100.000%	(10)	
	549	1	(18,962)	SG	27.756%	(5,263)	
	553	1	(2,240)	SG	27.756%	(622)	
	554	1	(38)	SG	27.756%	(11)	
	557	1	(51,145)	SG	27.756%	(14,195)	
	558WP	1	(9,033)	SG	27.756%	(2,507)	
	559	1	(823)	SG	27.756%	(229)	
	560	1	(17,360)	SG	27.756%	(4,818)	
	561	1	(7,809)	SG	27.756%	(2,167)	
	563	1	(267)	SG	27.756%	(74)	
	566	1	(1,399)	SG	27.756%	(388)	
	568	1	(9,592)	SG	27.756%	(2,662)	
	569	1	(641)	SG	27.756%	(178)	
	570	1	(4,099)	SG	27.756%	(1,138)	
	571	1	(3,693)	SG	27.756%	(1,025)	
	580	1	(1,718)	OR	100.000%	(1,718)	
	580	1	(149,215)	SNPD	25.578%	(38,166)	
	581	1	(6,243)	SNPD	25.578%	(1,597)	
			(426,771)			(116,316)	

Adjustment Description:

This adjustment removes the disallowance that was ordered by the Commission in Docket UE 374, Order 20-473, and further modified in accordance with Order UE 433, Order 24-447. The Commission ruled that all meals and entertainment, awards, on-site meals & refreshment, catering services-non employees, and coffee/water/beverage service-employees expenses would be disallowed at 50%.

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Oregon General Rate Case - December 2027
Meals & Entertainment Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Disallowance Removal	582	1	(232)	OR	100.00%	(232)	
	583	1	(542)	OR	100.00%	(542)	
	585	1	(354)	SNPD	25.58%	(91)	
	587	1	(102)	OR	100.00%	(102)	
	588	1	(8,945)	OR	100.00%	(8,945)	
	588	1	(13,798)	SNPD	25.58%	(3,529)	
	590	1	(7,804)	OR	100.00%	(7,804)	
	590	1	(73,171)	SNPD	25.58%	(18,716)	
	592	1	(609)	OR	100.00%	(609)	
	592	1	(25,768)	SNPD	25.58%	(6,591)	
	593	1	(24,934)	OR	100.00%	(24,934)	
	593	1	(24,310)	SNPD	25.58%	(6,218)	
	594	1	(694)	OR	100.00%	(694)	
	595	1	(892)	SNPD	25.58%	(228)	
	597	1	(227)	SNPD	25.58%	(58)	
	598	1	(24,979)	SNPD	25.58%	(6,389)	
	901	1	(9,095)	CN	30.14%	(2,741)	
	902	1	(1,049)	CN	30.14%	(316)	
	902	1	(612)	OR	100.00%	(612)	
	903	1	(2,042)	CN	30.14%	(616)	
	903	1	-	OR	100.00%	-	
	908	1	(9,648)	CN	30.14%	(2,908)	
	908	1	(11,884)	OR	100.00%	(11,884)	
	909	1	(7,751)	CN	30.14%	(2,336)	
	910	1	(83)	CN	30.14%	(25)	
	921	1	(0)	OR	100.00%	(0)	
	921	1	(69,318)	SO	28.25%	(19,584)	
	929	1	817	SO	28.25%	231	
	935	1	(2,639)	SO	28.25%	(746)	
	542	1	(575)	SG-P	27.76%	(160)	
	545	1	6,024	SG-P	27.76%	1,672	
	543	1	(10)	SG-U	27.76%	(3)	
			(315,227)			(125,710)	
Total Adjustment			**(741,998)**			**(242,026)**	**4.9.2**

Adjustment Description:

This adjustment removes the disallowance that was ordered by the Commission in Docket UE 374, Order 20-473, and further modified in accordance with Order UE 433, Order 24-447. The Commission ruled that all meals and entertainment, awards, on-site meals & refreshment, catering services-non employees, and coffee/water/beverage service-employees expenses would be disallowed at 50%.

PacifiCorp
Oregon General Rate Case - December 2027
Meals & Entertainment Adjustment

GL Account	Description	Expenses Subject to Sharing	Adjustment	REF#
503120	Meals & Entertainment	816,539	(408,269)	**4.9.3 & 4.9.6**
503425	Awards	31,070	(15,535)	**4.9.5 & 4.9.6**
503115	On-Site Meals & Refreshment	615,738	(307,869)	**4.9.4 & 4.9.6**
530035	Catering Services-Non Employees	6,140	(3,070)	**4.9.5**
503430	Coffee/Water/Beverage Service-Employees	14,511	(7,255)	**4.9.5**
			(741,998)	**4.9.1**

PacifiCorp

Oregon General Rate Case - December 2027
Meals & Entertainment Adjustment
Account 503120 - Meals & Entertainment
Actual Expenses - 12 Months Ended June 2025

FERC Account	Allocation	Amount
500	SG	1,888
501	SE	-
502	SG	1,109
503	SE	23
505	SG	-
506	SG	23,416
511	SG	3,452
512	SG	560
513	SG	1,902
514	SG	11,410
535	SG-P	1,316
535	SG-U	11,673
536	SG-P	336
537	SG-P	1,463
537	SG-U	232
539	SG-P	11,486
539	SG-U	12,240
543	SG-P	247
544	SG-P	(85)
544	SG-U	610
545	SG-U	433
546	SG	300
548	SG	2,221
549	OR	20
549	SG	19,173
553	SG	2,767
554	SG	77
557	SG	73,233
558WP	SG	14,660
559	SG	234
560	SG	25,343
561	SG	9,545
563	SG	534
566	SG	904
568	SG	16,194
569	SG	1,109
570	SG	4,790
571	SG	6,088
580	OR	3,217
580	SNPD	130,350
581	SNPD	1,589
582	OR	157
583	OR	1,430
585	SNPD	708
587	OR	204
Grand Total		**398,558**

FERC Account	Allocation	Amount
588	OR	5,748
588	SNPD	20,162
590	OR	13,772
590	SNPD	131,263
592	OR	562
592	SNPD	27,066
593	OR	17,544
593	SNPD	42,375
594	OR	1,159
595	SNPD	1,220
597	SNPD	366
598	SNPD	4,640
901	CN	10,855
902	CN	1,889
902	OR	391
903	CN	2,730
908	CN	14,848
908	OR	16,702
909	CN	10,482
910	CN	2
921	OR	(1)
921	SO	101,026
929	SO	(1,182)
935	SO	4,063
Grand Total		**427,685**

Account 503120 Total	**826,243**

Ref 4.9.2

PacifiCorp
Oregon General Rate Case - December 2027
Meals & Entertainment Adjustment
Account 503115 - On-Site Meals & Refreshments
Actual Expenses - 12 Months Ended June 2025

FERC Account	Allocation	Amount
500	SG	21,744
502	SG	4,723
506	SG	83,785
511	SG	5,110
512	SG	483
513	SG	14,804
514	SG	190
535	SG-P	1,021
535	SG-U	2,879
536	SG-P	22
537	SG-P	1,008
539	SG-P	19,495
539	SG-U	13,043
542	SG-P	1,150
543	SG-P	611
544	SG-P	371
545	SG-P	(12,887)
545	SG-U	131
546	SG	2,291
548	SG	3,071
549	SG	12,383
553	SG	1,712
557	SG	27,563
558WP	SG	3,406
559	SG	1,413
560	SG	9,249
561	SG	6,064
566	SG	1,868
568	SG	2,990
569	SG	173
570	SG	3,399
571	SG	1,191
580	OR	218
580	SNPD	162,558
581	SNPD	10,897
582	OR	300
583	OR	(346)
588	OR	11,966
588	SNPD	7,332
590	OR	1,836
590	SNPD	15,080
592	OR	656
592	SNPD	24,380
593	OR	32,325
593	SNPD	5,814
594	OR	229
Grand Total		**507,699**

FERC Account	Allocation	Amount
595	SNPD	563
597	SNPD	87
598	SNPD	45,318
901	CN	6,785
902	CN	200
902	OR	820
903	CN	1,333
908	CN	4,448
908	OR	6,857
909	CN	5,020
910	CN	164
921	OR	1
921	SO	43,555
929	SO	(453)
935	SO	1,214
Grand Total		**115,912**

Account 503115 Total	**623,611**

Ref 4.9.2

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Oregon General Rate Case - December 2027

Meals & Entertainment Adjustment

Coffee/Water Beverages, Catering-Non-Employee, and Awards

Actual Expenses - 12 Months Ended June 2025

Account 503430 - Coffee/Water/Bev.

FERC Account	Allocation	Amount
506	SG	7
535	SG-U	14
537	SG-P	3,103
539	SG-P	3,671
539	SG-U	6,946
543	SG-U	19
560	SG	1
561	SG	10
566	SG	26
568	SG	1
571	SG	106
580	SNPD	5
588	OR	176
588	SNPD	3
593	SNPD	431
902	OR	12
921	SO	(21)
935	SO	2
Grand Total		**14,511**
		Ref 4.9.2

Account 503425 - Awards

FERC Account	Allocation	Amount
506	SG	2,346
511	SG	47
514	SG	6
545	SG-P	840
546	SG	207
549	SG	6,370
557	SG	1,493
560	SG	127
570	SG	10
580	SNPD	5,517
582	OR	8
588	SNPD	99
592	SNPD	90
901	CN	550
902	CN	9
903	CN	21
908	OR	210
921	SO	13,360
Grand Total		**31,310**
		Ref 4.9.2

Account 530035 Catering-Non-Emp.

FERC Account	Allocation	Amount
506	SG	1,308
514	SG	6,298
921	SO	(1,466)
Grand Total		**6,140**
		Ref 4.9.2

PacifiCorp Page 4.9.6
Oregon General Rate Case - December 2027
Meals & Entertainment Adjustment
Actual Expenses - 12 Months Ended June 2025

Expenses Removed in Adjustment 4.1

FERC Account	Allocation	Account Number	Amount	
921	SO	503115	7,873	**Ref 4.9.2**
921	SO	503120	9,704	**Ref 4.9.2**
921	SO	503425	240	**Ref 4.9.2**
			17,817	
			Ref 4.9.2	

Note - These expenses are being excluded from this adjustment since they have been fully removed in Adjustment 4.1.

PacifiCorp PAGE 4.10
Oregon General Rate Case - December 2027
O&M Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	113,005	SG	27.756%	31,365	
Steam Operations	501	3	1,171,500	SE	26.823%	314,229	
Steam Operations	502	3	2,369,325	SG	27.756%	657,620	
Steam Operations	503	3	(7,110)	SE	26.823%	(1,907)	
Steam Operations	505	3	59,648	SG	27.756%	16,556	
Steam Operations	506	3	1,095,997	SG	27.756%	304,200	
Steam Operations	507	3	28,411	SG	27.756%	7,886	
Steam Maintenance	510	3	472,857	SG	27.756%	131,244	
Steam Maintenance	511	3	770,754	SG	27.756%	213,927	
Steam Maintenance	512	3	2,470,483	SG	27.756%	685,697	
Steam Maintenance	513	3	1,300,348	SG	27.756%	360,919	
Steam Maintenance	514	3	617,532	SG	27.756%	171,399	
Hydro Operations	535	3	(53,976)	SG	27.756%	(14,981)	
Hydro Operations	535	3	163,554	SG-P	27.756%	45,395	
Hydro Operations	535	3	(302,958)	SG-U	27.756%	(84,088)	
Hydro Operations	536	3	(6,390)	SG-P	27.756%	(1,774)	
Hydro Operations	537	3	156,547	SG-P	27.756%	43,451	
Hydro Operations	537	3	12,075	SG-U	27.756%	3,351	
Hydro Operations	539	3	113,664	SG-P	27.756%	31,548	
Hydro Operations	539	3	108,014	SG-U	27.756%	29,980	
Hydro Operations	540	3	54,259	SG-P	27.756%	15,060	
Hydro Operations	540	3	3,878	SG-U	27.756%	1,076	
Hydro Maintenance	541	3	16	SG-P	27.756%	4	
Hydro Maintenance	542	3	8,304	SG-P	27.756%	2,305	
Hydro Maintenance	542	3	1,323	SG-U	27.756%	367	
Hydro Maintenance	543	3	6,872	SG-P	27.756%	1,907	
Hydro Maintenance	543	3	18,128	SG-U	27.756%	5,032	
Hydro Maintenance	544	3	3,588	SG-P	27.756%	996	
Hydro Maintenance	544	3	19,431	SG-U	27.756%	5,393	
Hydro Maintenance	545	3	145,212	SG-P	27.756%	40,304	
Hydro Maintenance	545	3	34,764	SG-U	27.756%	9,649	
Solar Operations	558XP	3	(58,037)	OR	Situs	(58,037)	
Wind Operations	558WP	3	1,289,442	SG	27.756%	357,892	
Other Renewable Operations	559	3	51,440	SG	27.756%	14,277	
Other Operations	546	3	20,710	SG	27.756%	5,748	
Other Operations	548	3	1,102,514	SG	27.756%	306,009	
Other Operations	549	3	218,166	SG	27.756%	60,553	
Other Operations	549	3	137	OR	Situs	137	
Other Operations	550	3	8,894	OR	Situs	8,894	
Other Operations	550	3	172,764	SG	27.756%	47,952	
Other Maintenance	552	3	84,045	SG	27.756%	23,327	
			13,839,126			3,794,864	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2025 to December 2027 for accounts 500 to 935 , excluding NPC property and liability insurance, and uncollectible expenses using industry specific escalation indices. Before escalation indices were applied, June 2025 actual data was separated into labor and non-labor components and costs that should not be included in June 2025 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the company's filing.

PacifiCorp PAGE 4.10.1
Oregon General Rate Case - December 2027
O&M Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Other Maintenance	553	3	843,337	SG	27.756%	234,073	
Other Maintenance	554	3	281,660	SG	27.756%	78,176	
Other Operations	556	3	124,930	SG	27.756%	34,675	
Other Operations	557	3	196,520	ID	Situs	-	
Other Operations	557	3	3,379	OR	Situs	3,379	
Other Operations	557	3	525,965	SG	27.756%	145,985	
Other Operations	557	3	407	SE	26.823%	109	
Other Operations	557	3	1,686	UT	Situs	-	
Other Operations	557	3	2,984	WYU	Situs	-	
Transmission Operations	560	3	132,107	SG	27.756%	36,667	
Transmission Operations	561	3	315,321	SG	27.756%	87,519	
Transmission Operations	562	3	39,326	SG	27.756%	10,915	
Transmission Operations	563	3	41,688	SG	27.756%	11,571	
Transmission Operations	566	3	161,663	SG	27.756%	44,871	
Transmission Operations	567	3	85,623	SG	27.756%	23,765	
Transmission Maintenance	568	3	(4,389)	SG	27.756%	(1,218)	
Transmission Maintenance	569	3	170,558	SG	27.756%	47,339	
Transmission Maintenance	570	3	234,910	SG	27.756%	65,201	
Transmission Maintenance	571	3	374,676	SG	27.756%	103,994	
Transmission Maintenance	572	3	5,078	SG	27.756%	1,409	
Transmission Maintenance	573	3	13,709	SG	27.756%	3,805	
Distribution Operations	580	3	(33,316)	CA	Situs	-	
Distribution Operations	580	3	4,189	ID	Situs	-	
Distribution Operations	580	3	171,135	OR	Situs	171,135	
Distribution Operations	580	3	(256,519)	SNPD	25.578%	(65,613)	
Distribution Operations	580	3	8,028	WA	Situs	-	
Distribution Operations	580	3	571	WYP	Situs	-	
Distribution Operations	580	3	60,819	UT	Situs	-	
Distribution Operations	580	3	352	WYU	Situs	-	
Distribution Operations	581	3	(22,498)	SNPD	25.578%	(5,755)	
Distribution Operations	582	3	2,134	CA	Situs	-	
Distribution Operations	582	3	7,485	ID	Situs	-	
Distribution Operations	582	3	33,786	OR	Situs	33,786	
Distribution Operations	582	3	21	SNPD	25.578%	5	
Distribution Operations	582	3	83,459	UT	Situs	-	
Distribution Operations	582	3	11,547	WA	Situs	-	
Distribution Operations	582	3	23,754	WYP	Situs	-	
Distribution Operations	583	3	(47,169)	CA	Situs	-	
Distribution Operations	583	3	7,359	ID	Situs	-	
Distribution Operations	583	3	(33,551)	OR	Situs	(33,551)	
Distribution Operations	583	3	150,049	UT	Situs	-	
			3,722,773			1,032,242	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2025 to December 2027 for accounts 500 to 935 , excluding NPC property and liability insurance, and uncollectible expenses using industry specific escalation indices. Before escalation indices were applied, June 2025 actual data was separated into labor and non-labor components and costs that should not be included in June 2025 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the company's filing.

PacifiCorp PAGE 4.10.2
Oregon General Rate Case - December 2027
O&M Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Distribution Operations	583	3	3,904	WA	Situs	-	
Distribution Operations	583	3	22,631	WYP	Situs	-	
Distribution Operations	583	3	1,756	WYU	Situs	-	
Distribution Operations	584	3	-	OR	Situs	-	
Distribution Operations	585	3	814	SNPD	25.578%	208	
Distribution Operations	586	3	1,529	CA	Situs	-	
Distribution Operations	586	3	2,400	ID	Situs	-	
Distribution Operations	586	3	13,047	OR	Situs	13,047	
Distribution Operations	586	3	41	SNPD	25.578%	11	
Distribution Operations	586	3	14,051	UT	Situs	-	
Distribution Operations	586	3	2,950	WA	Situs	-	
Distribution Operations	586	3	4,503	WYP	Situs	-	
Distribution Operations	586	3	977	WYU	Situs	-	
Distribution Operations	587	3	7,000	CA	Situs	-	
Distribution Operations	587	3	9,944	ID	Situs	-	
Distribution Operations	587	3	65,216	OR	Situs	65,216	
Distribution Operations	587	3	140,352	UT	Situs	-	
Distribution Operations	587	3	14,648	WA	Situs	-	
Distribution Operations	587	3	21,784	WYP	Situs	-	
Distribution Operations	587	3	1,620	WYU	Situs	-	
Distribution Operations	588	3	(955)	CA	Situs	-	
Distribution Operations	588	3	2,239	ID	Situs	-	
Distribution Operations	588	3	(41,044)	OR	Situs	(41,044)	
Distribution Operations	588	3	(1,285,575)	SNPD	25.578%	(328,825)	
Distribution Operations	588	3	17,142	UT	Situs	-	
Distribution Operations	588	3	(5,456)	WA	Situs	-	
Distribution Operations	588	3	13,369	WYP	Situs	-	
Distribution Operations	588	3	(4,006)	WYU	Situs	-	
Distribution Operations	589	3	911	CA	Situs	-	
Distribution Operations	589	3	2,788	ID	Situs	-	
Distribution Operations	589	3	79,425	OR	Situs	79,425	
Distribution Operations	589	3	25,735	SNPD	25.578%	6,582	
Distribution Operations	589	3	20,964	UT	Situs	-	
Distribution Operations	589	3	7,327	WA	Situs	-	
Distribution Operations	589	3	13,183	WYP	Situs	-	
Distribution Operations	589	3	290	WYU	Situs	-	
Distribution Operations	590	3	1,184	CA	Situs	-	
Distribution Operations	590	3	77	ID	Situs	-	
Distribution Operations	590	3	8,774	OR	Situs	8,774	
Distribution Operations	590	3	3,910	SNPD	25.578%	1,000	
Distribution Operations	590	3	70,775	UT	Situs	-	
			(739,775)			(195,607)	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2025 to December 2027 for accounts 500 to 935 , excluding NPC property and liability insurance, and uncollectible expenses using industry specific escalation indices. Before escalation indices were applied, June 2025 actual data was separated into labor and non-labor components and costs that should not be included in June 2025 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the company's filing.

PacifiCorp PAGE 4.10.3
Oregon General Rate Case - December 2027
O&M Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Distribution Operations	590	3	1,682	WA	Situs	-	
Distribution Operations	590	3	3,168	WYP	Situs	-	
Distribution Operations	591	3	4,670	CA	Situs	-	
Distribution Operations	591	3	4,828	ID	Situs	-	
Distribution Operations	591	3	60,690	OR	Situs	60,690	
Distribution Operations	591	3	5,631	SNPD	25.578%	1,440	
Distribution Operations	591	3	56,803	UT	Situs	-	
Distribution Operations	591	3	9,235	WA	Situs	-	
Distribution Operations	591	3	9,191	WYP	Situs	-	
Distribution Operations	591	3	3,084	WYU	Situs	-	
Distribution Operations	592	3	14,719	CA	Situs	-	
Distribution Operations	592	3	27,259	ID	Situs	-	
Distribution Operations	592	3	63,886	OR	Situs	63,886	
Distribution Operations	592	3	78,931	SNPD	25.578%	20,189	
Distribution Operations	592	3	60,873	UT	Situs	-	
Distribution Operations	592	3	28,520	WA	Situs	-	
Distribution Operations	592	3	19,525	WYP	Situs	-	
Distribution Operations	592	3	(1,002)	WYU	Situs	-	
Distribution Operations	593	3	316,491	CA	Situs	-	
Distribution Operations	593	3	56,500	ID	Situs	-	
Distribution Operations	593	3	(862,641)	OR	Situs	(862,641)	
Distribution Operations	593	3	468,333	OTHER	0.000%	-	
Distribution Operations	593	3	19,275	SNPD	25.578%	4,930	
Distribution Operations	593	3	843,209	UT	Situs	-	
Distribution Operations	593	3	242,382	WA	Situs	-	
Distribution Operations	593	3	178,520	WYP	Situs	-	
Distribution Operations	593	3	22,597	WYU	Situs	-	
Distribution Operations	594	3	7,717	CA	Situs	-	
Distribution Operations	594	3	31,351	ID	Situs	-	
Distribution Operations	594	3	234,990	OR	Situs	234,990	
Distribution Operations	594	3	135	SNPD	25.578%	35	
Distribution Operations	594	3	621,732	UT	Situs	-	
Distribution Operations	594	3	57,115	WA	Situs	-	
Distribution Operations	594	3	69,188	WYP	Situs	-	
Distribution Operations	594	3	8,194	WYU	Situs	-	
Distribution Operations	595	3	10,832	SNPD	25.578%	2,771	
Distribution Operations	596	3	519	CA	Situs	-	
Distribution Operations	596	3	619	ID	Situs	-	
Distribution Operations	596	3	10,320	OR	Situs	10,320	
Distribution Operations	596	3	17,767	UT	Situs	-	
Distribution Operations	596	3	694	WA	Situs	-	
			2,807,533			(463,390)	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2025 to December 2027 for accounts 500 to 935 , excluding NPC property and liability insurance, and uncollectible expenses using industry specific escalation indices. Before escalation indices were applied, June 2025 actual data was separated into labor and non-labor components and costs that should not be included in June 2025 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the company's filing.

PacifiCorp PAGE 4.10.4
Oregon General Rate Case - December 2027
O&M Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Distribution Operations	596	3	6,729	WYP	Situs	-	
Distribution Operations	596	3	1,370	WYU	Situs	-	
Distribution Operations	597	3	202	CA	Situs	-	
Distribution Operations	597	3	193	ID	Situs	-	
Distribution Operations	597	3	1,864	OR	Situs	1,864	
Distribution Operations	597	3	808	SNPD	25.578%	207	
Distribution Operations	597	3	2,465	UT	Situs	-	
Distribution Operations	597	3	2,239	WA	Situs	-	
Distribution Operations	597	3	257	WYP	Situs	-	
Distribution Operations	597	3	333	WYU	Situs	-	
Distribution Operations	598	3	7,106	CA	Situs	-	
Distribution Operations	598	3	7,471	ID	Situs	-	
Distribution Operations	598	3	43,832	OR	Situs	43,832	
Distribution Operations	598	3	118,213	SNPD	25.578%	30,237	
Distribution Operations	598	3	53,434	UT	Situs	-	
Distribution Operations	598	3	24,074	WA	Situs	-	
Distribution Operations	598	3	9,727	WYP	Situs	-	
Customer Accounts Operations	901	3	154,831	CN	30.140%	46,666	
Customer Accounts Operations	902	3	4,308	CA	Situs	-	
Customer Accounts Operations	902	3	13,589	CN	30.140%	4,096	
Customer Accounts Operations	902	3	3,022	ID	Situs	-	
Customer Accounts Operations	902	3	34,565	OR	Situs	34,565	
Customer Accounts Operations	902	3	37,351	UT	Situs	-	
Customer Accounts Operations	902	3	12,175	WA	Situs	-	
Customer Accounts Operations	902	3	18,440	WYP	Situs	-	
Customer Accounts Operations	902	3	3,767	WYU	Situs	-	
Customer Accounts Operations	903	3	830	CA	Situs	-	
Customer Accounts Operations	903	3	689,424	CN	30.140%	207,791	
Customer Accounts Operations	903	3	2,479	ID	Situs	-	
Customer Accounts Operations	903	3	24,360	OR	Situs	24,360	
Customer Accounts Operations	903	3	53,871	UT	Situs	-	
Customer Accounts Operations	903	3	173,517	WA	Situs	-	
Customer Accounts Operations	903	3	7,774	WYP	Situs	-	
Customer Accounts Operations	903	3	991	WYU	Situs	-	
Customer Accounts Operations	904	3	-	CA	Situs	-	
Customer Accounts Operations	904	3	-	CN	30.140%	-	
Customer Accounts Operations	904	3	-	ID	Situs	-	
Customer Accounts Operations	904	3	-	OR	Situs	-	
Customer Accounts Operations	904	3	-	UT	Situs	-	
Customer Accounts Operations	904	3	-	WA	Situs	-	
Customer Accounts Operations	904	3	-	WYP	Situs	-	
			1,515,611			393,617	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2025 to December 2027 for accounts 500 to 935 , excluding NPC property and liability insurance, and uncollectible expenses using industry specific escalation indices. Before escalation indices were applied, June 2025 actual data was separated into labor and non-labor components and costs that should not be included in June 2025 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the company's filing.

PacifiCorp PAGE 4.10.5
Oregon General Rate Case - December 2027
O&M Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Customer Accounts Operations	905	3	0	OR	Situs	0	
Customer Service Operations	908	3	6,356	CA	Situs	-	
Customer Service Operations	908	3	25,359	CN	30.140%	7,643	
Customer Service Operations	908	3	1,278	ID	Situs	-	
Customer Service Operations	908	3	10,008	OR	Situs	10,008	
Customer Service Operations	908	3	10,157,395	OTHER	0.000%	-	
Customer Service Operations	908	3	(62,148)	UT	Situs	-	
Customer Service Operations	908	3	139,827	WA	Situs	-	
Customer Service Operations	908	3	4,082	WYP	Situs	-	
Customer Service Operations	909	3	7,229	CA	Situs	-	
Customer Service Operations	909	3	32,831	CN	30.140%	9,895	
Customer Service Operations	909	3	4,031	ID	Situs	-	
Customer Service Operations	909	3	29,235	OR	Situs	29,235	
Customer Service Operations	909	3	33,730	UT	Situs	-	
Customer Service Operations	909	3	10,935	WA	Situs	-	
Customer Service Operations	909	3	9,731	WYP	Situs	-	
Customer Service Operations	910	3	3,066	CN	30.140%	924	
A & G Operations	920	3	(137)	CA	Situs	-	
A & G Operations	920	3	(16,568)	OR	Situs	(16,568)	
A & G Operations	920	3	(293,678)	SO	27.909%	(81,962)	
A & G Operations	920	3	(30)	UT	Situs	-	
A & G Operations	920	3	(897)	WYP	Situs	-	
A & G Operations	921	3	83	CA	Situs	-	
A & G Operations	921	3	6,481	CN	30.140%	1,953	
A & G Operations	921	3	149	ID	Situs	-	
A & G Operations	921	3	29,822	OR	Situs	29,822	
A & G Operations	921	3	1,115,593	SO	27.909%	311,350	
A & G Operations	921	3	6,688	UT	Situs	-	
A & G Operations	921	3	539	WA	Situs	-	
A & G Operations	921	3	1,347	WYP	Situs	-	
A & G Operations	921	3	102	WYU	Situs	-	
A & G Operations	922	3	(1,515,077)	SO	27.909%	(422,841)	
A & G Operations	923	3	20,515	CA	Situs	-	
A & G Operations	923	3	118	ID	Situs	-	
A & G Operations	923	3	2,534	OR	Situs	2,534	
A & G Operations	923	3	1,642,617	SO	27.909%	458,436	
A & G Operations	923	3	17,684	UT	Situs	-	
A & G Operations	923	3	34,843	WA	Situs	-	
A & G Operations	923	3	2,179	WYP	Situs	-	
A & G Operations	923	3	3,748	WYU	Situs	-	
A & G Operations	928	3	34,421	CA	Situs	-	
			11,506,022			340,429	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2025 to December 2027 for accounts 500 to 935 , excluding NPC property and liability insurance, and uncollectible expenses using industry specific escalation indices. Before escalation indices were applied, June 2025 actual data was separated into labor and non-labor components and costs that should not be included in June 2025 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

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Oregon General Rate Case - December 2027
O&M Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
A & G Operations	928	3	30,249	ID	Situs	-	
A & G Operations	928	3	503,360	OR	Situs	503,360	
A & G Operations	928	3	202,388	SG	27.756%	56,174	
A & G Operations	928	3	104,720	SO	27.909%	29,226	
A & G Operations	928	3	349,209	UT	Situs	-	
A & G Operations	928	3	78,891	WA	Situs	-	
A & G Operations	928	3	142,645	WYP	Situs	-	
A & G Operations	929	3	1,644,243	SO	27.909%	458,890	
A & G Operations	930	3	(26)	CA	Situs	-	
A & G Operations	930	3	(10,562)	OR	Situs	(10,562)	
A & G Operations	930	3	58,089	SO	27.909%	16,212	
A & G Operations	930	3	(96,591)	SG	27.756%	(26,809)	
A & G Operations	930	3	(109)	WA	Situs	-	
A & G Operations	930	3	2,671	WYP	Situs	-	
A & G Operations	931	3	152	CA	Situs	-	
A & G Operations	931	3	2,068	OR	Situs	2,068	
A & G Operations	931	3	16,256	SO	27.909%	4,537	
A & G Operations	931	3	41	UT	Situs	-	
A & G Operations	931	3	126	WA	Situs	-	
A & G Operations	931	3	512	WYP	Situs	-	
A & G Operations	935	3	8,289	CA	Situs	-	
A & G Operations	935	3	3,390	CN	30.140%	1,022	
A & G Operations	935	3	2,004	ID	Situs	-	
A & G Operations	935	3	13,775	OR	Situs	13,775	
A & G Operations	935	3	1,448,094	SO	27.909%	404,147	
A & G Operations	935	3	5,055	UT	Situs	-	
A & G Operations	935	3	8,927	WA	Situs	-	
A & G Operations	935	3	1,479	WYP	Situs	-	
A & G Operations	935	3	(204)	WYU	Situs	-	
			4,519,138			1,452,038	
			13,839,126			3,794,864	4.10
			3,722,773			1,032,242	4.10.1
			(739,775)			(195,607)	4.10.2
			2,807,533			(463,390)	4.10.3
			1,515,611			393,617	4.10.4
			11,506,022			340,429	4.10.5
			4,519,138			1,452,038	4.10.6
Total Adjustment			37,170,427			6,354,194	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2025 to December 2027 for accounts 500 to 935 , excluding NPC property and liability insurance, and uncollectible expenses using industry specific escalation indices. Before escalation indices were applied, June 2025 actual data was separated into labor and non-labor components and costs that should not be included in June 2025 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

PacifiCorp
Oregon General Rate Case - December 2027
O&M Escalation
12 Months Ending December 2027

Function	Allocation Code	Unadjusted O&M	4.1 Miscellaneous General Expense & Revenue	4.2 Remove Unadjusted Wages & Employee Benefits_CONF	4.4 Remove Non-Recurring Entries	4.5 Insurance Expense	4.6 Generation Overhaul Expense	4.8 Membership & Subscriptions	4.9 Meals and Entertainment Adjustment	4.11 Wildfire Mitigation and Vegetation Management Expenses
Steam Operation										
	NPCID	(360,325)	-	-	-	-	-	-	-	-
	NPCSE	795,709,623	-	-	-	-	-	-	-	-
	NPCWYP	(972,366)	-	-	-	-	-	-	-	-
	NPCSG	26,044,626	-	-	-	-	-	-	-	-
	SE	22,159,971	-	(134,479)	-	-	-	-	(11)	-
	SG	140,405,930	-	(68,919,626)	-	-	-	-	(70,163)	-
	Steam Operation Total	982,987,458	-	(69,054,105)	-	-	-	-	(70,175)	-
Steam Maintenance										
	SG	156,781,822	-	(51,425,179)	-	-	8,608,045	-	(22,131)	-
	Steam Maintenance Total	156,781,822	-	(51,425,179)	-	-	8,608,045	-	(22,131)	-
Hydro Operations										
	SG-P	25,361,150	-	(11,440,438)	-	-	-	-	(21,460)	-
	SG-U	13,605,155	-	(18,747,063)	-	-	-	-	(23,513)	-
	SG	-	-	-	-	-	-	-	-	-
	Hydro Operations Total	38,966,305	-	(30,187,501)	-	-	-	-	(44,973)	-
Hydro Maintenance										
	SG-P	6,153,358	-	(2,166,589)	-	-	-	-	4,876	-
	SG-U	2,281,496	-	(488,317)	-	-	-	-	(596)	-
	SG	3,435,915	-	-	(3,435,915)	-	-	-	-	-
	Hydro Maintenance Total	11,870,769	-	(2,654,906)	(3,435,915)	-	-	-	4,280	-
Solar Power Operations										
	OR	208,052	-	(1,412,700)	-	-	-	-	-	-
	Solar Power Total	208,052	-	(1,412,700)	-	-	-	-	-	-
Wind Power Operations										
	SG	27,619,506	-	(11,457)	-	-	-	-	(9,033)	-
	Solar Power Total	27,619,506	-	(11,457)	-	-	-	-	(9,033)	-
Other Renewable Operations										
	SG	1,482,364	-	(413,824)	-	-	-	-	(823)	-
	Solar Power Total	1,482,364	-	(413,824)	-	-	-	-	(823)	-
Purchased Power										
	NPCSE	(18,915,422)	-	-	-	-	-	-	-	-
	NPCSG	1,261,541,362	-	-	-	-	-	-	-	-
	NPCCA	183,180	-	-	-	-	-	-	-	-
	NPCOR	868,834	-	-	-	-	-	-	-	-
	NPCUT	19,828,610	-	-	-	-	-	-	-	-
	OTHER	285,964,068	-	-	-	-	-	-	-	-
	Purchase Power Total	1,549,470,632	-	-	-	-	-	-	-	-
Other Operations										
	NPCSE	394,476,811	-	-	-	-	-	-	-	-
	SE	8,450	-	-	-	-	-	-	-	-
	SG	93,318,764	-	(48,286,518)	-	-	-	-	(74,152)	-
	ID	4,122,398	-	(43,293)	-	-	-	-	-	-
	OR	12,085,480	-	(17,394)	-	-	-	-	(10)	-
	UT	35,000	-	-	-	-	-	-	-	-
	WYU	61,932	-	-	-	-	-	-	-	-
	Other Operations Total	504,108,835	-	(48,347,205)	-	-	-	-	(74,162)	-
Other Maintenance										
	SG	32,239,980	-	(3,635,678)	-	-	(2,953,598)	-	(2,278)	-
	Other Maintenance Total	32,239,980	-	(3,635,678)	-	-	(2,953,598)	-	(2,278)	-
Transmission Operations										
	NPCSE	26,339,197	-	-	-	-	-	-	-	-
	NPCSG	161,546,869	-	-	-	-	-	-	-	-
	SG	47,605,469	-	(27,587,903)	-	-	-	-	(26,835)	-
	Transmission Operations Total	235,491,535	-	(27,587,903)	-	-	-	-	(26,835)	-
Transmission Maintenance										
	SG	53,538,501	-	(18,812,565)	-	-	-	-	(18,025)	(16,398,385)
	Transmission Maintenance Total	53,538,501	-	(18,812,565)	-	-	-	-	(18,025)	(16,398,385)

Exhibit PAC/802
McCoy/123

PacifiCorp
Oregon General Rate Case - December 2027
O&M Escalation
12 Months Ending December 2027

Function	Allocation Code	Unadjusted O&M	4.1 Miscellaneous General Expense & Revenue	4.2 Remove Unadjusted Wages & Employee Benefits_CONF	4.4 Remove Non-Recurring Entries	4.5 Insurance Expense	4.6 Generation Overhaul Expense	4.8 Membership & Subscriptions	4.9 Meals and Entertainment Adjustment	4.11 Wildfire Mitigation and Vegetation Management Expenses
Distribution Operations										
	CA	1,778,698	-	(3,332,600)	-	-	-	-	-	-
	ID	2,743,549	-	(1,933,883)	-	-	-	-	-	-
	OR	17,634,080	-	(11,216,754)	-	-	-	-	(11,539)	-
	SNPD	23,862,745	-	(57,899,833)	-	-	-	-	(169,610)	-
	UT	24,767,485	-	(13,939,617)	-	-	-	-	-	-
	WA	3,070,422	-	(2,115,192)	-	-	-	-	-	-
	WYP	5,393,761	-	(3,174,175)	-	-	-	-	-	-
	WYU	392,187	-	(370,190)	-	-	-	-	-	-
	Distribution Operations Total	79,642,927	-	(93,982,245)	-	-	-	-	(181,150)	-
Distribution Maintenance										
	CA	14,985,870	-	(6,815,616)	-	-	-	-	-	-
	ID	8,150,950	-	(5,178,172)	-	-	-	-	-	-
	OR	115,293,829	-	(43,318,206)	-	-	-	-	(34,041)	(82,097,074)
	OTHER	10,851,714	-	-	-	-	-	-	-	-
	SNPD	16,634,976	-	(10,977,057)	-	-	-	-	(149,346)	-
	UT	76,658,888	-	(36,641,333)	-	-	-	-	-	-
	WA	16,279,170	-	(7,799,966)	-	-	-	-	-	-
	WYP	15,353,019	-	(8,487,329)	-	-	-	-	-	-
	WYU	1,889,786	-	(1,088,613)	-	-	-	-	-	-
	Distribution Maintenance Total	276,098,204	-	(120,306,292)	-	-	-	-	(183,388)	(82,097,074)
Customer Accounts Operations										
	CA	515,269	-	(418,264)	-	-	-	-	-	-
	CN	52,207,501	(262,229)	(35,736,547)	-	-	-	-	(12,186)	-
	ID	333,476	-	(229,612)	-	-	-	-	-	-
	OR	3,009,345	(6,901)	(1,889,286)	-	-	-	-	(612)	-
	UT	6,332,485	-	(4,610,159)	-	-	-	-	-	-
	WA	4,907,590	-	(1,401,646)	-	-	-	-	-	-
	WYP	1,838,737	-	(1,343,816)	-	-	-	-	-	-
	WYU	369,022	-	(279,188)	-	-	-	-	-	-
	904	26,303,880	-	-	-	-	-	-	-	-
	Customer Accounts Operations Total	95,817,305	(269,130)	(45,908,517)	-	-	-	-	(12,798)	-
Customer Service Operations										
	CA	407,507	79,984	(193,798)	-	-	-	-	-	-
	CN	7,598,869	(243,209)	(6,008,309)	-	-	-	-	(17,482)	(5,571)
	ID	144,057	1,222	(30,519)	-	-	-	-	-	-
	OR	2,670,892	166,505	(1,987,010)	-	-	-	-	(11,884)	9,885
	OTHER	219,599,590	-	(8,395)	-	-	-	-	-	-
	UT	2,225,716	-	(2,840,075)	-	-	-	-	-	-
	WA	3,668,803	405	(409,895)	-	-	-	-	-	-
	WYP	1,244,707	823	(946,914)	-	-	-	-	-	-
	WYU	-	-	-	-	-	-	-	-	-
	Customer Service Operations Total	237,560,141	5,730	(12,424,915)	-	-	-	-	(29,367)	4,314
A&G Operations & Maintenance										
	920	88,267,973	-	(92,838,908)	-	-	-	-	-	212,167
	921	14,733,630	6,280,198	(40,126)	-	-	-	-	(69,318)	37,807
	922	(45,396,046)	-	23,271,753	-	-	-	-	-	-
	923	50,094,018	-	-	-	-	-	-	-	710,398
	924	24,932,607	-	-	-	-	-	-	-	-
	925	261,347,734	-	-	-	(96,239,927)	-	-	-	-
	926	(6,947,718)	-	-	-	-	-	-	-	-
	928	34,435,140	-	(1,080,535)	-	-	-	-	-	-
	929	(14,685,943)	-	38,868,769	-	-	-	-	817	-
	930	2,527,744	-	-	-	-	-	(871,239)	-	(291,214)
	931	761,997	-	-	-	-	-	-	-	1,183
	935	38,788,617	-	(2,261,073)	-	-	-	-	(2,639)	43,344
	A&G Operations & Maintenance Total	448,859,752	6,280,198	(34,080,119)	-	(96,239,927)	-	(871,239)	(71,141)	713,686
	Grand Total	4,732,744,086	6,016,798	(560,245,111)	(3,435,915)	(96,239,927)	5,654,447	(871,239)	(741,998)	(97,777,459)

Exhibit PAC/802
McCoy/124

PacifiCorp
Oregon General Rate Case - December 2027
O&M Escalation
12 Months Ending December 2027

Function	Allocation Code	5.1 NPC Adjustment	8.10 Remove Rolling Hills	8.11 Deer Creek Mine Adjustment	8.12 Emissions Control Investment Adjustment	8.14 Cholla Unit 4 Retirement	8.19 Klamath Regulatory Asset	O&M Before Escalation	Escalation Percentages	4.10 O&M Expense Escalation	O&M After Escalation
Steam Operation											
	NPCID	360,325	-	-	-	-	-	(0)	0.00%	-	(0)
	NPCSE	(795,709,623)	-	-	-	-	-	0	0.00%	-	0
	NPCWYP	972,366	-	-	-	-	-	-	0.00%	-	0
	NPCSG	(26,044,626)	-	-	-	-	-	-	0.00%	-	0
	SE	-	-	-	-	-	-	22,025,480	5.29%	1,164,390	23,189,870
	SG	-	-	(2,063,172)	-	-	-	69,352,968	5.29%	3,666,385	73,019,353
	Steam Operation Total	(820,421,557)	-	(2,063,172)	-	-	-	91,378,448		4,830,775	96,209,223
Steam Maintenance											
	SG	-	-	-	-	-	-	113,942,556	4.94%	5,631,973	119,574,529
	Steam Maintenance Total	-	-	-	-	-	-	113,942,556		5,631,973	119,574,529
Hydro Operations											
	SG-P	-	-	-	-	-	-	13,899,252	3.47%	481,634	14,380,886
	SG-U	-	-	-	-	-	-	(5,165,421)	3.47%	(178,991)	(5,344,413)
	SG	-	-	-	-	-	(1,557,679)	(1,557,679)	3.47%	(53,976)	(1,611,655)
	Hydro Operations Total	-	-	-	-	-	(1,557,679)	7,176,152		248,667	7,424,819
Hydro Maintenance											
	SG-P	-	-	-	-	-	-	3,991,646	4.11%	163,991	4,155,636
	SG-U	-	-	-	-	-	-	1,792,582	4.11%	73,646	1,866,228
	SG	-	-	-	-	-	-	-	4.11%	-	0
	Hydro Maintenance Total	-	-	-	-	-	-	5,784,228		237,636	6,021,864
Solar Power Operations											
	OR	-	-	-	-	-	-	(1,204,648)	4.82%	(58,037)	(1,262,684)
	Solar Power Total	-	-	-	-	-	-	(1,204,648)		(58,037)	(1,262,684)
Wind Power Operations											
	SG	-	(834,466)	-	-	-	-	26,764,550	4.82%	1,289,442	28,053,992
	Solar Power Total	-	(834,466)	-	-	-	-	26,764,550		1,289,442	28,053,992
Other Renewable Operations											
	SG	-	-	-	-	-	-	1,067,717	4.82%	51,440	1,119,156
	Solar Power Total	-	-	-	-	-	-	1,067,717		51,440	1,119,156
Purchased Power											
	NPCSE	18,915,422	-	-	-	-	-	(0)	0.00%	-	(0)
	NPCSG	(1,261,541,362)	-	-	-	-	-	(0)	0.00%	-	(0)
	NPCCA	(183,180)	-	-	-	-	-	0	0.00%	-	0
	NPCOR	(868,834)	-	-	-	-	-	0	0.00%	-	0
	NPCUT	(19,828,610)	-	-	-	-	-	(0)	0.00%	-	(0)
	OTHER	-	-	-	-	-	-	285,964,068	0.00%	-	285,964,068
	Purchase Power Total	(1,263,506,564)	-	-	-	-	-	285,964,068		-	285,964,068
Other Operations											
	NPCSE	(394,476,811)	-	-	-	-	-	-	0.00%	-	-
	SE	-	-	-	-	-	-	8,450	4.82%	407	8,857
	SG	-	(18,836)	-	-	-	-	44,939,258	4.82%	2,165,049	47,104,307
	ID	-	-	-	-	-	-	4,079,105	4.82%	196,520	4,275,625
	OR	(11,810,478)	-	-	-	-	-	257,597	4.82%	12,410	270,008
	UT	-	-	-	-	-	-	35,000	4.82%	1,686	36,686
	WYU	-	-	-	-	-	-	61,932	4.82%	2,984	64,916
	Other Operations Total	(406,287,289)	(18,836)	-	-	-	-	49,381,343		2,379,056	51,760,399
Other Maintenance											
	SG	-	(741,748)	-	-	-	-	24,906,678	4.85%	1,209,042	26,115,720
	Other Maintenance Total	-	(741,748)	-	-	-	-	24,906,678		1,209,042	26,115,720
Transmission Operations											
	NPCSE	(26,339,197)	-	-	-	-	-	0	0.00%	-	0
	NPCSG	(161,546,869)	-	-	-	-	-	0	0.00%	-	0
	SG	-	-	-	-	-	-	19,990,731	3.88%	775,728	20,766,458
	Transmission Operations Total	(187,886,066)	-	-	-	-	-	19,990,731		775,728	20,766,458
Transmission Maintenance											
	SG	-	-	-	-	-	-	18,309,525	4.34%	794,543	19,104,068
	Transmission Maintenance Total	-	-	-	-	-	-	18,309,525		794,543	19,104,068

Exhibit PAC/802
McCoy/125

PacifiCorp
Oregon General Rate Case - December 2027
O&M Escalation
12 Months Ending December 2027

Function	Allocation Code	5.1 NPC Adjustment	8.10 Remove Rolling Hills	8.11 Deer Creek Mine Adjustment	8.12 Emissions Control Investment Adjustment	8.14 Cholla Unit 4 Retirement	8.19 Klamath Regulatory Asset	O&M Before Escalation	Escalation Percentages	4.10 O&M Expense Escalation	O&M After Escalation
Distribution Operations											
	CA	-	-	-	-	-	-	(1,553,902)	4.50%	(69,866)	(1,623,767)
	ID	-	-	-	-	-	-	809,666	4.50%	36,404	846,070
	OR	-	-	-	-	-	-	6,405,786	4.50%	288,013	6,693,799
	SNPD	-	-	-	-	-	-	(34,206,698)	4.50%	(1,537,981)	(35,744,680)
	UT	-	-	-	-	-	-	10,827,868	4.50%	486,836	11,314,705
	WA	-	-	-	-	-	-	955,230	4.50%	42,948	998,178
	WYP	-	-	-	-	-	-	2,219,586	4.50%	99,796	2,319,382
	WYU	-	-	-	-	-	-	21,996	4.50%	989	22,985
	Distribution Operations Total	-	-	-	-	-	-	(14,520,467)		(652,861)	(15,173,328)
Distribution Maintenance											
	CA	-	-	-	-	-	-	8,170,254	4.32%	352,608	8,522,862
	ID	-	-	-	-	-	-	2,972,779	4.32%	128,298	3,101,076
	OR	-	-	-	-	-	-	(10,155,492)	4.32%	(438,286)	(10,593,777)
	OTHER	-	-	-	-	-	-	10,851,714	4.32%	468,333	11,320,047
	SNPD	-	-	-	-	-	-	5,508,572	4.32%	237,736	5,746,308
	UT	-	-	-	-	-	-	40,017,554	4.32%	1,727,057	41,744,612
	WA	-	-	-	-	-	-	8,479,204	4.32%	365,941	8,845,146
	WYP	-	-	-	-	-	-	6,865,690	4.32%	296,306	7,161,996
	WYU	-	-	-	-	-	-	801,174	4.32%	34,577	835,750
	Distribution Maintenance Total	-	-	-	-	-	-	73,511,450		3,172,570	76,684,020
Customer Accounts Operations											
	CA	-	-	-	-	-	-	97,005	5.30%	5,138	102,143
	CN	-	-	-	-	-	-	16,196,539	5.30%	857,844	17,054,383
	ID	-	-	-	-	-	-	103,864	5.30%	5,501	109,365
	OR	-	-	-	-	-	-	1,112,547	5.30%	58,926	1,171,472
	UT	-	-	-	-	-	-	1,722,326	5.30%	91,222	1,813,549
	WA	-	-	-	-	-	-	3,505,944	5.30%	185,691	3,691,636
	WYP	-	-	-	-	-	-	494,921	5.30%	26,213	521,134
	WYU	-	-	-	-	-	-	89,834	5.30%	4,758	94,592
	904	-	-	-	-	-	-	26,303,880	0.00%	-	26,303,880
	Customer Accounts Operations Total	-	-	-	-	-	-	49,626,859		1,235,294	50,862,153
Customer Service Operations											
	CA	-	-	-	-	-	-	293,693	4.63%	13,585	307,278
	CN	-	-	-	-	-	-	1,324,299	4.63%	61,257	1,385,555
	ID	-	-	-	-	-	-	114,759	4.63%	5,308	120,068
	OR	-	-	-	-	-	-	848,388	4.63%	39,243	887,631
	OTHER	-	-	-	-	-	-	219,591,195	4.63%	10,157,395	229,748,590
	UT	-	-	-	-	-	-	(614,359)	4.63%	(28,418)	(642,777)
	WA	-	-	-	-	-	-	3,259,313	4.63%	150,763	3,410,075
	WYP	-	-	-	-	-	-	298,617	4.63%	13,813	312,429
	WYU	-	-	-	-	-	-	-	4.63%	-	0
	Customer Service Operations Total	-	-	-	-	-	-	225,115,904		10,412,946	235,528,850
A&G Operations & Maintenance											
	920	-	-	-	-	(187,213)	-	(4,545,980)	6.85%	(311,310)	(4,857,290)
	921	-	-	-	-	-	-	20,942,190	5.54%	1,160,805	22,102,995
	922	-	-	-	-	-	-	(22,124,293)	6.85%	(1,515,077)	(23,639,370)
	923	-	-	-	-	-	-	50,804,417	3.39%	1,724,237	52,528,654
	924	-	-	-	-	-	-	24,932,607	0.00%	-	24,932,607
	925	-	-	-	-	-	-	165,107,806	0.00%	-	165,107,806
	926	-	-	-	-	-	-	(6,947,718)	0.00%	-	(6,947,718)
	928	-	-	-	-	-	-	33,354,605	4.33%	1,445,884	34,800,489
	929	-	(173,175)	-	-	-	-	24,010,468	6.85%	1,644,243	25,654,710
	930	-	-	-	(2,634,206)	-	-	(1,268,916)	3.67%	(46,529)	(1,315,444)
	931	-	-	-	-	(9,837)	-	753,343	2.54%	19,155	772,498
	935	-	-	-	-	-	-	36,568,249	4.08%	1,490,807	38,059,055
	A&G Operations & Maintenance Total	-	(173,175)	-	(2,634,206)	(197,050)	-	321,586,778		5,612,214	327,198,992
	Grand Total	(2,678,101,477)	(1,768,225)	(2,063,172)	(2,634,206)	(197,050)	(1,557,679)	1,298,781,873		37,170,427	1,335,952,300
										Ref 4.10.6	

Exhibit PAC/802
McCoy/126

PacifiCorp
Oregon General Rate Case - December 2027
O&M Escalation
Escalation Factors

Note: Please see Confidential Exhibit PAC/805 for details of escalation factors.

	Escalation Factors	
	June 2025 to December 2027	**FERC Accounts**
STEAM PRODUCTION PLANT		
Operation:	5.29%	500 - 507
Maintenance:	4.94%	510 - 514
HYDRO PRODUCTION PLANT		
Operation:	3.47%	535 - 540
Maintenance:	4.11%	541 - 545
OTHER PRODUCTION PLANT		
Operation:	4.82%	546 - 550; 556 - 559
Maintenance:	4.85%	551 - 554
TRANSMISSION PLANT		
Operation:	3.88%	560 - 567
Maintenance:	4.34%	568 - 573
DISTRIBUTION PLANT		
Operation:	4.50%	580 - 589
Maintenance:	4.32%	590 - 598
CUSTOMER ACCOUNTS		
Operation:	5.30%	901 - 903, 905
CUSTOMER SERVICE and INFORMATION		
Operation:	4.63%	907 - 910
SALES		
Operation:	4.77%	911 - 916
ADMINISTRATIVE and GENERAL		
Operation:	6.85%	920, 922, 929
Operation:	5.54%	921
Operation:	3.39%	923
Operation:	9.80%	926
Operation:	6.00%	927
Operation:	4.33%	928
Operation:	3.67%	930
Operation:	2.54%	931
Maintenance:	4.08%	935

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Oregon General Rate Case - December 2027
Wildfire Mitigation and Vegetation Management Expenses

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Base Period Expenses							
Vegetation Management	593	1	(38,425,979)	OR	Situs	(38,425,979)	4.11.1
Vegetation Management	571	1	(14,270,112)	SG	27.756%	(3,960,752)	4.11.1
Vegetation Management	593	1	(18,000,709)	OR	Situs	(18,000,709)	4.11.3
Wildfire Mitigation	593	1	(5,000,433)	OR	Situs	(5,000,433)	4.11.2
Wildfire Mitigation	571	1	(2,128,272)	SG	27.756%	(590,714)	4.11.2
Wildfire Mitigation	593	1	(20,669,953)	OR	Situs	(20,669,953)	4.11.3
Wildfire Mitigation	908	1	(5,571)	CN	30.140%	(1,679)	4.11.3
Wildfire Mitigation	909	1	9,885	OR	Situs	9,885	4.11.3
Wildfire Mitigation	920	1	212,167	OR	Situs	212,167	4.11.3
Wildfire Mitigation	921	1	37,807	OR	Situs	37,807	4.11.3
Wildfire Mitigation	923	1	710,398	OR	Situs	710,398	4.11.3
Wildfire Mitigation	930	1	(291,527)	OR	Situs	(291,527)	4.11.3
Wildfire Mitigation	930	1	314	SO	27.909%	88	4.11.3
Wildfire Mitigation	931	1	1,183	OR	Situs	1,183	4.11.3
Wildfire Mitigation	935	1	43,344	OR	Situs	43,344	4.11.3
Add Test Period Expenses							
Vegetation Management	593	3	61,000,000	OR	Situs	61,000,000	4.11.1

Description of Adjustment

This adjustment reduces the level of vegetation management expenses reflected in base rates from the approved $67 million per docket No. UE-433 to $61 million for the 12 months ending December 2027.

This adjustment also removes any operations & maintenance or amortization expenses recorded in the 12 months ended June 2025 related to wildfire mitigation and vegetation management. All wildfire mitigation expenses are recovered through the Automatic Adjustment Clause (Schedule 190) effective January 1, 2025 as approved in Order 24-447 in docket No. UE-433. Amortization of deferred vegetation management expense are recovered annually through Schedule 94.

PacifiCorp Page 4.11.1
Oregon General Rate Case - December 2027
Wildfire Mitigation and Vegetation Management Expenses
Summary of Vegetation Management Expenses in Base Period Results

Ln no.	Expenses in Rates	Vegetation Management	Ref.
1	O&M in Base Rates - CY2023 & CY 2024	$ 50,000,000	*UE-399*
2	O&M in Base Rates - CY2025	$ 67,000,000	*UE-433*
3	O&M in Base Rates - CY2027	$ 61,000,000	*Proposed*
	Expenses in Base Period		
4	Gross Expense - Situs	$ 58,474,057	
5	Gross Expense - Transmission	$ 14,270,112	
	Deferral Entries in Base Period Results		
6	Deferral Amounts - Situs	$ 20,048,079	
	Net Expenses reported in Base Period		
7	Net Expense - Situs	$ 38,425,979	Line 4 - Line 6
8	Net Expense - Transmission	$ 14,270,112	Line 5

PacifiCorp Page 4.11.2
Oregon General Rate Case - December 2027
Wildfire Mitigation and Vegetation Management Expenses
Summary of Wildfire Mitigation Expenses in Base Period Results - Deferral

Ln no.				
	Expenses in Base Period Results			
1	Gross Expense - Situs	$	23,403,538	
2	Gross Expense - Transmission	$	2,128,272	
	Deferral Entries in Base Period Results			
3	Deferral Amounts - Situs	$	18,403,105	
	Net Expenses reported in Base Period Results			
4	Net Expense - Situs	$	5,000,433	Line 1 - Line 3
5	Net Expense - Transmission	$	2,128,272	Line 2

PacifiCorp
Oregon General Rate Case - December 2027
Wildfire Mitigation and Vegetation Management Expenses
Summary of Amortization Expense in Base Period Results

FERC Account	Alloc.	Wildfire Mitigation	
593	OR	20,669,953	
908	CN	5,571	
909	OR	(9,885)	
920	OR	(212,167)	
921	OR	(37,807)	
923	OR	(710,398)	
930	OR	291,527	
930	SO	(314)	
931	OR	(1,183)	
935	OR	(43,344)	
Net Amortization in Base Period		**19,951,953**	**Ref 4.11**

FERC Account	Alloc.	Vegetation Management	
593	OR	18,000,709	
Net Amortization in Base Period		**18,000,709**	**Ref 4.11**

PacifiCorp PAGE 4.12
Oregon General Rate Case - December 2027
Customer Payment Fees

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Customer Account Expense	903	3	1,251,165	OR	Situs	1,251,165	4.12.1
Customer Account Expense	921	3	(701,977)	OR	Situs	(701,977)	4.12.1

Description of Adjustment:

Per docket UE-433, Order No. 24-447, the Commission supported the elimination of payment fees for residential customers effective January 1, 2025 to make payment easier and to eliminate a barrier for vulnerable customers. This adjustment walks forward the actual customer payment fees recorded in the 12 months ended June 2025 to the test period levels as approved in docket UE-433.

PacifiCorp
Oregon General Rate Case - December 2027
Customer Payment Fees
Summary of Adjustments

FERC	Alloc.	12 Months Ended June 2025	UE-433 Authorized	Adjustment	
903	OR	137,636	1,388,801	**1,251,165**	**Ref 4.12**
921	OR	701,977	-	**(701,977)**	**Ref 4.12**

PacifiCorp
Oregon General Rate Case - December 2027
Summary of Approved Payment Fees by Type - Docket No. UE-433

			Fee Count						
Customer Accounts Expense	**FERC Acct**	**Alloc.**	**2021**	**2022**	**2023**	**3-Yr. Avg.**	**Current Fee**		**Total Co. ($)**
Pay Station	903	OR	79,193	76,386	77,021	77,533	$	1.65	127,930
Residential ACH Payment	903	OR	26,863	22,388	23,989	24,413	$	1.99	48,583
Residential Card Payment	903	OR	532,960	602,167	692,444	609,190	$	1.99	1,212,289
									1,388,801
									Ref. 4.12.1

Tab 5 - Net Power Cost

PacifiCorp **Page 5.0.1**
Oregon General Rate Case – December 2027
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 2025 provide the starting point for establishing the adjustment amounts for the December 2027 test period.

5.1 Net Power Cost Adjustment
5.2 WRAP, BOSR & COSR Material Costs

PacifiCorp
Oregon General Rate Case - December 2027
Tab 5 Adjustment Summary

		Total Adjustments	5.1 Net Power Cost Adjustment	5.2 WRAP, BOSR & COSR Material Costs
1	Operating Revenues:			
2	General Business Revenues	-	-	-
3	Interdepartmental	-	-	-
4	Special Sales	19,747,968	19,747,968	-
5	Other Operating Revenues	-	-	-
6	Total Operating Revenues	19,747,968	19,747,968	-
7				
8	Operating Expenses:			
9	Steam Production	(46,107,869)	(46,107,869)	-
10	Nuclear Production	-	-	-
11	Hydro Production	-	-	-
12	Solar Production	-	-	-
13	Wind Production	-	-	-
14	Other Renewable Production	1,565,734	1,565,734	-
15	Other Power Supply	(39,034,848)	(39,116,855)	82,008
16	Transmission	14,709,743	14,709,743	-
17	Distribution	-	-	-
18	Customer Accounting	-	-	-
19	Customer Service & Info	-	-	-
20	Sales	-	-	-
21	Administrative & General	(40,745)	-	(40,745)
22				
23	Total O&M Expenses	(68,907,986)	(68,949,249)	41,262
24			-	-
25	Depreciation	-	-	-
26	Amortization	-	-	-
27	Taxes Other Than Income	-	-	-
28	Income Taxes - Federal	17,780,254	17,788,531	(8,277)
29	Income Taxes - State	4,026,735	4,028,610	(1,874)
30	Income Taxes - Def Net	-	-	-
31	Investment Tax Credit Adj.	-	-	-
32	Misc Revenue & Expense	-	-	-
33				
34	Total Operating Expenses:	(47,100,997)	(47,132,108)	31,111
35				
36	Operating Rev For Return:	66,848,965	66,880,076	(31,111)
37				
38	Rate Base:			
39	Electric Plant In Service	-	-	-
40	Plant Held for Future Use	-	-	-
41	Misc Deferred Debits	-	-	-
42	Elec Plant Acq Adj	-	-	-
43	Nuclear Fuel	-	-	-
44	Prepayments	-	-	-
45	Fuel Stock	-	-	-
46	Material & Supplies	-	-	-
47	Working Capital	(1,429,098)	(1,430,042)	944
48	Weatherization Loans	-	-	-
49	Misc Rate Base	-	-	-
50				
51	Total Electric Plant:	(1,429,098)	(1,430,042)	944
52			-	-
53	Rate Base Deductions:		-	-
54	Accum Prov For Deprec	-	-	-
55	Accum Prov For Amort	-	-	-
56	Accum Def Income Tax	-	-	-
57	Unamortized ITC	-	-	-
58	Customer Adv For Const	-	-	-
59	Customer Service Deposits	-	-	-
60	Misc Rate Base Deductions	-	-	-
61				
62	Total Rate Base Deductions	-	-	-
63				
64	Total Rate Base:	(1,429,098)	(1,430,042)	944
65				
66	Return on Rate Base	1.047%	1.047%	0.000%
67				
68	Return on Equity	2.094%	2.095%	-0.001%
69				
70	TAX CALCULATION:			
71	Operating Revenue	88,655,954	88,697,217	(41,262)
72	Other Deductions	-	-	-
73	Interest (AFUDC)	-	-	-
74	Interest	(38,657)	(38,683)	26
75	Schedule "M" Additions	-	-	-
76	Schedule "M" Deductions	-	-	-
77	Income Before Tax	88,694,612	88,735,899	(41,288)
78				
79	State Income Taxes	4,026,735	4,028,610	(1,874)
80	Taxable Income	84,667,876	84,707,289	(39,413)
81				
82	Federal Income Taxes + Other	17,780,254	17,788,531	(8,277)
	APPROXIMATE PRICE CHANGE	(91,897,852)	(91,940,650)	42,797

PacifiCorp PAGE 5.1
Oregon General Rate Case - December 2027
Net Power Cost Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Sales for Resale (Account 447)							
Existing Firm PPL	447NPC	1	-	SG	27.756%	-	5.1.2
Existing Firm UPL	447NPC	1	-	SG	27.756%	-	5.1.2
Post-Merger Firm	447NPC	1	(124,884,481)	SG	27.756%	(34,662,405)	5.1.2
Non-Firm	447NPC	1	1,506,975	SE	26.823%	404,213	5.1.2
Total Sales for Resale			(123,377,506)			(34,258,193)	
Adjustment to Expense:							
Purchased Power (Account 555)							
Existing Firm Demand PPL	555NPC	1	-	SG	27.756%	-	5.1.2
Existing Firm Demand UPL	555NPC	1	-	SG	27.756%	-	5.1.2
Existing Firm Energy	555NPC	1	-	SE	26.823%	-	5.1.2
Post-merger Firm	555NPC	1	(1,261,541,362)	SG	27.756%	(350,148,055)	5.1.2
Post-merger Firm - Situs	555NPC	1	(19,828,610)	UT	0.000%	-	5.1.2
Post-merger Firm - Situs	555NPC	1	(868,834)	OR	100.000%	(868,834)	5.1.2
Post-merger Firm - Situs	555NPC	1	(183,180)	CA	0.000%	-	5.1.2
Secondary Purchases	555NPC	1	18,915,422	SE	26.823%	5,073,643	5.1.2
Post-merger Firm Type 1	555NPC	1	78,884,124	SG	27.756%	21,894,742	5.1.2
Total Purchased Power Adjustments:			(1,184,622,440)			(324,048,504)	
Wheeling Expense (Account 565)							
Existing Firm PPL	565NPC	1	-	SG	27.756%	-	5.1.2
Existing Firm UPL	565NPC	1	-	SG	27.756%	-	5.1.2
Post-merger Firm	565NPC	1	(161,546,869)	SG	27.756%	(44,838,262)	5.1.2
Non-Firm	565NPC	1	(26,339,197)	SE	26.823%	(7,064,907)	5.1.2
Total Wheeling Expense Adjustments:			(187,886,066)			(51,903,168)	
Fuel Expense (Accounts 501, 503, 547)							
Fuel - Overburden Amortization - Idaho	501NPC	1	360,325	ID	0.000%	-	5.1.2
Fuel - Overburden Amortization - Wyoming	501NPC	1	972,366	WYP	0.000%	-	5.1.2
Fuel Consumed - Coal	501NPC	1	(625,266,424)	SE	26.823%	(167,713,879)	5.1.2
Fuel Consumed - Gas	501NPC	1	(164,981,170)	SE	26.823%	(44,252,547)	5.1.2
Steam from Other Sources	503NPC	1	(5,462,029)	SE	26.823%	(1,465,068)	5.1.2
GHG Allowances	509NPC	1	(26,044,626)	SG	27.756%	(7,228,836)	5.1.2
Natural Gas Consumed	547NPC	1	(394,109,085)	SE	26.823%	(105,711,039)	5.1.2
Simple Cycle Combustion Turbines	547NPC	1	(367,726)	SE	26.823%	(98,634)	5.1.2
Other Production Wind	547NPC	1	-	SG	27.756%	-	5.1.2
Other Renewable Fuel	559NPC	1	-	SE	27.756%	-	5.1.2
Total Fuel Expense Adjustments:			(1,214,898,368)			(326,470,003)	
Total Power Cost Adjustment			(2,464,029,369)			(668,163,482)	
Post-merger Firm Type 1	555NPC	1	(78,884,124)	SG	27.756%	(21,894,742)	5.1.2
Remove from Base Rates							
Oregon Transition Adjustment Expense	557	1	(11,810,478)	OR	100.000%	(11,810,478)	5.1.6

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 2027. The Aurora study for this adjustment is based on forecast loads for the period.

As described in the testimony of Shelley E. McCoy, 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.

PacifiCorp PAGE 5.1.1
Oregon General Rate Case - December 2027
Net Power Cost Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Sales for Resale (Account 447)							
Existing Firm PPL	447NPC	3	-	OR	100.000%	-	5.1.2
Existing Firm UPL	447NPC	3	-	OR	100.000%	-	5.1.2
Post-Merger Firm	447NPC	3	54,006,161	OR	100.000%	54,006,161	5.1.2
Non-Firm	447NPC	3	-	OR	100.000%	-	5.1.2
Total Sales for Resale			54,006,161			54,006,161	
Adjustment to Expense:							
Purchased Power (Account 555)							
Existing Firm Demand PPL	555NPC	3	7,358,436	OR	100.000%	7,358,436	5.1.2
Existing Firm Demand UPL	555NPC	3	54,339	OR	100.000%	54,339	5.1.2
Existing Firm Energy	555NPC	3	16,557,798	OR	100.000%	16,557,798	5.1.2
Post-merger Firm	555NPC	3	256,129,275	OR	100.000%	256,129,275	5.1.2
Post-merger Firm - Situs	555NPC	3	-	OR	100.000%	-	5.1.2
Post-merger Firm - Situs	555NPC	3	-	OR	100.000%	-	5.1.2
Post-merger Firm - Situs	555NPC	3	-	OR	100.000%	-	5.1.2
Secondary Purchases	555NPC	3	-	OR	100.000%	-	5.1.2
Total Purchased Power Adjustments:			280,099,848			280,099,848	
Wheeling Expense (Account 565)							
Existing Firm PPL	565NPC	3	6,815,753	OR	100.000%	6,815,753	5.1.2
Existing Firm UPL	565NPC	3	-	OR	100.000%	-	5.1.2
Post-merger Firm	565NPC	3	56,139,514	OR	100.000%	56,139,514	5.1.2
Non-Firm	565NPC	3	3,657,644	OR	100.000%	3,657,644	5.1.2
Total Wheeling Expense Adjustments:			66,612,911			66,612,911	
Fuel Expense (Accounts 501, 503, 547)							
Fuel - Overburden Amortization - Idaho	501NPC	3	-	OR	100.000%	-	5.1.2
Fuel - Overburden Amortization - Wyoming	501NPC	3	-	OR	100.000%	-	5.1.2
Fuel Consumed - Coal	501NPC	3	166,737,467	OR	100.000%	166,737,467	5.1.2
Fuel Consumed - Gas	501NPC	3	7,814,993	OR	100.000%	7,814,993	5.1.2
Steam from Other Sources	503NPC	3	-	OR	100.000%	-	5.1.2
GHG Allowances	509NPC	3	-	OR	100.000%	-	5.1.2
Natural Gas Consumed	547NPC	3	137,879,298	OR	100.000%	137,879,298	5.1.2
Simple Cycle Combustion Turbines	547NPC	3	2,666,678	OR	100.000%	2,666,678	5.1.2
Other Production Wind	547NPC	3	-	OR	100.000%	-	5.1.2
Other Renewable Fuel	559NPC	3	1,565,734	OR	100.000%	1,565,734	5.1.2
Total Fuel Expense Adjustments:			316,664,170			316,664,170	
Total Power Cost Adjustment			609,370,769			609,370,769	
Oregon Situs NPC Adjustments	555NPC	3	3,800,717	OR	100.000%	3,800,717	5.1.5

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 2027. The Aurora study for this adjustment is based on forecast loads for the period.

As described in the testimony of Shelley E. McCoy, 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.

PacifiCorp
Oregon General Rate Case - December 2027
Net Power Cost Adjustment

Description	FERC Account	(1) Total Account (B Tabs)	(2) Remove Non-NPC / NPC Mechanism Accruals	(3) Unadjusted NPC Total Company (1) + (2)	(4) Type 1 Adjustments	(5) Type 1 Remove Normalized NPC	(6) Type 3 Pro Forma NPC Total Company	(7) Allocation Factor	(8) UE-469 TAM Oregon Allocated Factor %	(9) Type 3 Adjustment Oregon Allocated (6) * (8)
Sales for Resale (Account 447)										
Existing Firm Sales PPL	447.12	-	-	-	-	-	-	SG	29.334%	-
Existing Firm Sales UPL	447.122	-	-	-	-	-	-	SG	29.334%	-
Post-merger Firm Sales	447.13, .14, .20, .61, .62	124,884,481	-	124,884,481	-	(124,884,481)	184,105,479	SG	29.334%	54,006,161
Non-firm Sales	447.5	(1,506,975)	-	(1,506,975)	-	1,506,975	-	SE	28.243%	-
Transmission Services	447.9	56,712	(56,712)	-	-	-	-	S	0.000%	-
On-system Wholesale Sales	447.1	16,835,960	(16,835,960)	-	-	-	-	S	0.000%	-
Total Revenue Adjustments		140,270,178	(16,892,672)	123,377,506	-	(123,377,506)	184,105,479			54,006,161
Purchased Power (Account 555)										
Existing Firm Demand PPL	555.66	-	-	-	-	-	25,084,702	SG	29.334%	7,358,436
Existing Firm Demand UPL	555.68	-	-	-	-	-	185,239	SG	29.334%	54,339
Existing Firm Energy	555.65, 555.69	-	-	-	-	-	58,627,179	SE	28.243%	16,557,798
Post-merger Firm	555.26, .55, .59, .61, .62, .63, .64, .67, .8	1,261,541,362	-	1,261,541,362	-	(1,261,541,362)	873,137,476	SG	29.334%	256,129,275
Post-merger Firm - Situs	555.27	19,828,610	-	19,828,610	-	(19,828,610)	-	UT	0.000%	-
Post-merger Firm - Situs	555.28	868,834	-	868,834	-	(868,834)	-	OR	100.000%	-
Post-merger Firm - Situs	555.29	183,180	-	183,180	-	(183,180)	-	CA	0.000%	-
Secondary Purchases	555.7, 555.25	(18,915,422)	-	(18,915,422)	-	18,915,422	-	SE	28.243%	-
NPC Deferral Mechanism	555.57	279,192,370	(279,192,370)	-	-	-	-	OTHER	0.000%	-
Seasonal Contracts		-	-	-	-	-	-	SG	29.334%	-
Wind Integration Charge		-	-	-	-	-	-	SG	29.334%	-
RPS Compliance Purchases	555.22,555.23,555.24	6,771,698	(6,771,698)	-	-	-	-	OTHER	0.000%	-
BPA Regional Adjustments	555.11, 555.12, 555.133	-	-	-	-	-	-	S	0.000%	-
Post-merger Firm Type 1		-	-	-	(78,884,124)	78,884,124	-	SG	29.334%	-
Total Purchased Power Adjustment		1,549,470,632	(285,964,068)	1,263,506,564	(78,884,124)	(1,184,622,440)	957,034,597			280,099,848
Wheeling (Account 565)										
Existing Firm PPL	565.26	-	-	-	-	-	23,234,710	SG	29.334%	6,815,753
Existing Firm UPL	565.27	-	-	-	-	-	-	SG	29.334%	-
Post-merger Firm	565.0, 565.46, 565.1	161,546,869	-	161,546,869	-	(161,546,869)	191,378,021	SG	29.334%	56,139,514
Non-firm	565.25	26,339,197	-	26,339,197	-	(26,339,197)	12,950,836	SE	28.243%	3,657,644
Total Wheeling Expense Adjustment		187,886,066	-	187,886,066	-	(187,886,066)	227,563,567			66,612,911
Fuel Expense (Accounts 501, 503 and 547)										
Fuel - Overburden Amortization - Idaho	501.12	(360,325)	-	(360,325)	-	360,325	-	ID	0.000%	-
Fuel - Overburden Amortization - Wyoming	501.12	(972,366)	-	(972,366)	-	972,366	-	WY	0.000%	-
Fuel Consumed - Coal	501.1	625,266,424	-	625,266,424	-	(625,266,424)	590,377,261	SE	28.243%	166,737,467
Fuel Consumed - Gas	501.35	164,981,170	-	164,981,170	-	(164,981,170)	27,671,011	SE	28.243%	7,814,993
Steam From Other Sources	503	5,462,029	-	5,462,029	-	(5,462,029)	-	SE	28.243%	-
Other Renewable Fuel	559.3	0	-	-	-	-	5,543,887	SE	28.243%	1,565,734
GHG Allowances	509	26,044,626	-	26,044,626	-	(26,044,626)	-	SG	29.334%	-
Natural Gas Consumed	547.1	394,109,085	-	394,109,085	-	(394,109,085)	488,197,427	SE	28.243%	137,879,298
Simple Cycle Combustion Turbines	547.1	367,726	-	367,726	-	(367,726)	9,442,065	SE	28.243%	2,666,678
Other Production - Wind	547	0	-	-	-	-	-	SG	29.334%	-
Fuel Regulatory Costs Deferral and Amort	501.15	0	-	-	-	-	-	S	0.000%	-
Fuel Regulatory Costs Deferral and Amort	501.13, .15	2,728,430	(2,728,430)	-	-	-	-	SE	28.243%	-
Miscellaneous Fuel Costs	501.0, .2, .3, .4, .45, .5, .51	19,431,541	(19,431,541)	-	-	-	-	SE	28.243%	-
Miscellaneous Fuel Costs - Cholla	501.2,501.45	0	-	-	-	-	-	SE	28.243%	-
Total Fuel Expense		1,237,058,339	(22,159,971)	1,214,898,368	-	(1,214,898,368)	1,121,231,649			316,664,170
Net Power Cost		**2,834,144,859**	**(291,231,367)**	**2,542,913,493**	**(78,884,124)**	**(2,464,029,369)**	**2,121,724,334**			**609,370,769**
						Ref 5.1	**Ref 5.1.4**			**Ref 5.1.1**

PacifiCorp **Study Results**
Oregon General Rate Case - December 2027 MERGED PEAK/ENERGY SPLIT
Net Power Cost Study **($)**

	Merged 1/2027 - 12/2027	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	-	-			
Post Merger	184,105,479				184,105,479
Utah Pre Merger	-	-			
NonFirm Sub Total	-			-	
TOTAL SPECIAL SALES	184,105,479	-	-	-	184,105,479
PURCHASED POWER & NET INTERCHANGE					
BPA Peak Purchase	-	-			
Pacific Capacity	-	-	-		
Mid Columbia	83,615,675	25,084,702	58,530,972		
Misc/Pacific	-	-	-		
Q.F. Contracts/PPL	117,846,759	-	-		117,846,759
Small Purchases west	-		-		
Pacific Sub Total	201,462,434	25,084,702	58,530,972	-	117,846,759
Gemstate	-		-		
GSLM	-		-		
QF Contracts/UPL	165,249,956	185,239	79,388		164,985,329
IPP Layoff	-	-	-		
Small Purchases east	16,818		16,818		
UP&L to PP&L	-	-	-		
Utah Sub Total	165,266,775	185,239	96,207	-	164,985,329
Amor IX	-		-		-
Anticline Wind	15,795,932		-		15,795,932
Boswell Springs Wind	33,509,985		-		33,509,985
Cedar Creek	20,759,709		-		20,759,709
Cedar Springs Wind	11,983,640		-		11,983,640
Cedar Springs Wind III	9,573,083		-		9,573,083
Cedar Springs Wind IV	36,051,431		-		36,051,431
Cove Mountain Solar	4,453,304		-		4,453,304
Elektron Solar	6,131,879		-		6,131,879
Green River Energy Center Solar	30,614,560		-		30,614,560
Hornshadow I Solar	9,790,392		-		9,790,392
Hornshadow II Solar	19,580,785		-		19,580,785
Hunter Solar	6,911,559		-		6,911,559
Milford Solar	6,494,658		-		6,494,658
Millican Solar	3,135,630		-		3,135,630
Nucor	8,160,000		-		8,160,000
Old Mill Solar	581,831		-		581,831
P4 Production	20,600,000		-		20,600,000
PGE Cove	211,211		-		211,211
Prineville Solar	2,032,154		-		2,032,154
Sigurd Solar	5,799,998		-		5,799,998
Three Buttes Wind	19,060,119		-		19,060,119
Top of the World Wind	22,751,965		-		22,751,965
UT Schedule 32/34 Excess Gen	7,904,130		-		7,904,130
Dominguez Grid Storage	34,776,000		-		34,776,000
Escalante 1 Storage	13,248,000		-		13,248,000
Enterprise Storage	13,248,000		-		13,248,000
Faraday Energy Storage	-		-		-
Granite Mountain East Storage	13,248,000		-		13,248,000
Green River Energy Center Storage	57,600,000		-		57,600,000
Iron Springs Storage	13,248,000		-		13,248,000
Oregon Institute of Technology Storage	-		-		-
Short Term Firm Purchases	143,049,434		-		143,049,434
New Firm Sub Total	590,305,388	-	-	-	590,305,388

PacifiCorp
Oregon General Rate Case - December 2027
Net Power Cost Study

Study Results
MERGED PEAK/ENERGY SPLIT
($)

	Merged 1/2027 - 12/2027	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	-	-			
Non Firm Sub Total	-			-	
TOTAL PURCHASED PW & NET INT.	957,034,597	25,269,941	58,627,179	-	873,137,476
WHEELING & U. OF F. EXPENSE					
Pacific Firm Wheeling and Use of Facilities	23,234,710	23,234,710			
Utah Firm Wheeling and Use of Facilities	-	-			
Post Merger	191,378,021				191,378,021
Nonfirm Wheeling	12,950,836			12,950,836	
TOTAL WHEELING & U. OF F. EXPENSE	227,563,567	23,234,710	-	12,950,836	191,378,021
THERMAL FUEL BURN EXPENSE					
Colstrip	24,719,615			24,719,615	
Craig	7,640,546			7,640,546	
Dave Johnston	64,744,500			64,744,500	
Hayden	12,379,971			12,379,971	
Hunter	198,404,834			198,404,834	
Huntington	160,214,578			160,214,578	
Jim Bridger	96,851,776			96,851,776	
Naughton	-			-	
Wyodak	25,421,441			25,421,441	
Chehalis	28,653,940			28,653,940	
Currant Creek	83,554,396			83,554,396	
Gadsby	27,671,011			27,671,011	
Gadsby CT	9,442,065			9,442,065	
Hermiston	31,127,920			31,127,920	
Jim Bridger - Gas	79,365,234			79,365,234	
Lake Side 1	105,625,997			105,625,997	
Lake Side 2	93,014,887			93,014,887	
Naughton - Gas	66,855,052			66,855,052	
TOTAL FUEL BURN EXPENSE	1,115,687,763	-	-	1,115,687,763	-
OTHER GENERATION EXPENSE					
Blundell	5,543,887			5,543,887	
Rolling Hills Wind	-			-	
TOTAL OTHER GEN. EXPENSE	5,543,887	-	-	5,543,887	-
NET POWER COST	2,121,724,334	48,504,652	58,627,179	1,134,182,486	880,410,018

PacifiCorp
Oregon General Rate Case - December 2027
Net Power Cost Adjustment
Oregon Situs Adjustments

	Total	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
Net Energy impact - Situs Solar	**4,136,885**	473,581	367,152	275,751	251,777	214,440	217,063	337,765	395,540	356,693	365,556	379,198	502,369
REP Adjustments (Oregon Allocation)	**(336,168)**	(20,206)	(19,524)	(13,852)	(25,504)	(32,670)	(47,319)	(32,095)	(18,431)	(23,550)	(34,955)	(29,227)	(38,836)
Total OR Situs Adjustment	**3,800,717**	453,375	347,628	261,899	226,273	181,769	169,745	305,669	377,109	333,143	330,602	349,971	463,533

PacifiCorp
Oregon General Rate Case - December 2027
Net Power Cost Adjustment
Oregon Transition Adjustment Expense Removal
GL Account 514700 - Actuals 12 Months Ended June 2025

Year	Month	Balance	
2024	7	605,538	
2024	8	1,242,899	
2024	9	1,891,242	
2024	10	1,625,173	
2024	11	906,687	
2024	12	1,500,816	
2025	1	496,883	
2025	2	294,276	
2025	3	902,121	
2025	4	854,520	
2025	5	1,031,441	
2025	6	458,882	
Total 12 ME June 2025		**11,810,478**	**Ref. 5.1**

PacifiCorp PAGE 5.2
Oregon General Rate Case - December 2027
WRAP, BOSR & COSR Material Costs

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove As Booked							
BOSR Fee	930	3	(98,250)	SO	27.909%	(27,421)	5.2.1
WRAP Fee	557	3	(1,092,251)	SG	27.756%	(303,161)	5.2.1
COSR Materials	930	3	(47,744)	SO	27.909%	(13,325)	5.2.1
			(1,238,246)			(343,906)	
Add Back Forecasts							
BOSR Fee	557	3	98,250	SG	27.756%	27,270	5.2.1
WRAP Fee	557	3	1,239,310	SG	27.756%	343,978	5.2.1
COSR Materials	557	3	50,155	SG	27.756%	13,921	5.2.1
			1,387,715			385,168	

Description of Adjustment:

This adjustment walks three fees in O&M costs to reflect pro forma levels and appropriate allocation. The first cost is for Energy Imbalance Market (EIM) Board of State Regulators (BOSR). The primary function of the BOSR is to provide a forum for state regulators to learn about the Western EIM, EIM Governing Body and related ISO developments that may be relevant to their jurisdictional responsibilities. Secondly, 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 third fee is regarding the Committee of State Regulators (COSR) Material Fees which are related to the implementation of the WRAP Program.

PacifiCorp
Oregon General Rate Case - December 2027
WRAP, BOSR & COSR Material Costs

		As Booked		
				12 ME
Fee Description	**FERC Acct**	**Allocation**		**June 2025**
EIM Board of State Regulators (BOSR)	930	SO	$	98,250
Western Resource Adequacy Program (WRAP)	557	SG	$	1,092,251
COSR Materials	930	SO	$	47,744
			$	**1,238,246**
				Ref 5.2

		Forecasted				
				12 ME	Partial Year	12 ME
Fee Description	**FERC Acct**	**Allocation**		**December 2027**	**Adjustment***	**December 2027**
EIM Board of State Regulators (BOSR)	557	SG	$	98,250	1	$ 98,250
Western Resource Adequacy Program (WRAP)	557	SG	$	1,487,172	5/6	$ 1,239,310
COSR Materials	557	SG	$	60,186	5/6	$ 50,155
						$ 1,387,715
						Ref 5.2

*Partial year adjustment represents pro-ration of WRAP fees (and associated COSR fees) due to anticipated termination on November 1, 2027.

Tab 6 - Depreciation & Amortization

PacifiCorp **Page 6.0.1**
Oregon General Rate Case – December 2027
Depreciation and Amortization Adjustment Index

The following adjustments were used to arrive at the normalized levels of depreciation and amortization expense along with the associated reserve balances reflected in the test period.

6.1 Depreciation and Amortization Expense
6.2 Depreciation and Amortization Reserve
6.3 Repowering Buy-Downs Adjustment
6.4 Bridger Mine Reclamation Costs and Decommissioning Cost

PacifiCorp
Oregon General Rate Case - December 2027
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 Mine Reclamation Costs and Decommissioning 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	(5,341,821)	-	-	-	(5,341,821)
10	Nuclear Production	-	-	-	-	-
11	Hydro Production	-	-	-	-	-
12	Solar Production	-	-	-	-	-
13	Wind Production	-	-	-	-	-
14	Other Renewable Production	-	-	-	-	-
15	Other Power Supply	-	-	-	-	-
16	Transmission	-	-	-	-	-
17	Distribution	-	-	-	-	-
18	Customer Accounting	-	-	-	-	-
19	Customer Service & Info	-	-	-	-	-
20	Sales	-	-	-	-	-
21	Administrative & General	-	-	-	-	-
22						
23	Total O&M Expenses	(5,341,821)	-	-	-	(5,341,821)
24			-	-	-	-
25	Depreciation	26,463,303	58,144,991	(31,681,688)	-	-
26	Amortization	(11,702,006)	(8,554,522)	-	(6,748,553)	3,601,069
27	Taxes Other Than Income	-	-	-	-	-
28	Income Taxes - Federal	2,216,908	(9,939,197)	11,037,636	2,162,842	(1,044,372)
29	Income Taxes - State	502,068	(2,250,953)	2,499,719	489,824	(236,521)
30	Income Taxes - Def Net	1,773,062	-	-	-	1,773,062
31	Investment Tax Credit Adj.	-	-	-	-	-
32	Misc Revenue & Expense	-	-	-	-	-
33			-	-	-	-
34	Total Operating Expenses:	13,911,514	37,400,319	(18,144,334)	(4,095,887)	(1,248,583)
35			-	-	-	-
36	Operating Rev For Return:	(13,911,514)	(37,400,319)	18,144,334	4,095,887	1,248,583
37						
38	Rate Base:					
39	Electric Plant In Service	-	-	-	-	-
40	Plant Held for Future Use	-	-	-	-	-
41	Misc Deferred Debits	-	-	-	-	-
42	Elec Plant Acq Adj	-	-	-	-	-
43	Nuclear Fuel	-	-	-	-	-
44	Prepayments	-	-	-	-	-
45	Fuel Stock	-	-	-	-	-
46	Material & Supplies	-	-	-	-	-
47	Working Capital	(9,082,253)	(369,863)	410,739	80,485	(9,203,614)
48	Weatherization Loans	-	-	-	-	-
49	Misc Rate Base	-	-	-	-	-
50						
51	Total Electric Plant:	(9,082,253)	(369,863)	410,739	80,485	(9,203,614)
52						
53	Rate Base Deductions:	-	-	-	-	-
54	Accum Prov For Deprec	(1,014,760,876)	-	(866,378,901)	(149,452,701)	1,070,726
55	Accum Prov For Amort	1,648,609	-	1,648,609	-	-
56	Accum Def Income Tax	3,141,294	-	60,743	-	3,080,551
57	Unamortized ITC	-	-	-	-	-
58	Customer Adv For Const	-	-	-	-	-
59	Customer Service Deposits	-	-	-	-	-
60	Misc Rate Base Deductions	(4,597,430)	-	-	-	(4,597,430)
61						
62	Total Rate Base Deductions	(1,014,568,403)	-	(864,669,549)	(149,452,701)	(446,153)
63						
64	Total Rate Base:	(1,023,650,656)	(369,863)	(864,258,810)	(149,372,216)	(9,649,767)
65						
66	Return on Rate Base	0.900%	-0.585%	1.187%	0.262%	0.036%
67						
68	Return on Equity	1.800%	-1.169%	2.374%	0.523%	0.071%
69						
70	TAX CALCULATION:					
71	Operating Revenue	(9,419,476)	(49,590,469)	31,681,688	6,748,553	1,740,751
72	Other Deductions	-	-	-	-	-
73	Interest (AFUDC)	-	-	-	-	-
74	Interest	(27,689,750)	(10,005)	(23,378,201)	(4,040,518)	(261,026)
75	Schedule "M" Additions	(7,211,499)	-	-	-	(7,211,499)
76	Schedule "M" Deductions	-	-	-	-	-
77	Income Before Tax	11,058,775	(49,580,464)	55,059,889	10,789,072	(5,209,722)
78						
79	State Income Taxes	502,068	(2,250,953)	2,499,719	489,824	(236,521)
80	Taxable Income	10,556,706	(47,329,511)	52,560,170	10,299,248	(4,973,200)
81						
82	Federal Income Taxes + Other	2,216,908	(9,939,197)	11,037,636	2,162,842	(1,044,372)
	APPROXIMATE PRICE CHANGE	(87,050,704)	51,293,285	(114,519,475)	(21,110,241)	(2,714,272)

PacifiCorp
Oregon General Rate Case - December 2027
Depreciation Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Depreciation Expense	403SP	3	1,083,109	SG	27.756%	300,623	
Steam Depreciation Expense	403SP	3	14,104,017	SG	27.756%	3,914,651	
Steam Depreciation Expense	403SP	3	62,167,960	SG	27.756%	17,255,074	
Steam Depreciation Expense	403SP	3	(77,177,362)	OTHER	0.000%	-	
Hydro Depreciation Expense	403HP	3	3,651,476	SG	27.756%	1,013,488	
Hydro Depreciation Expense	403HP	3	(75,363)	SG	27.756%	(20,918)	
Hydro Depreciation Expense	403HP	3	298,842	SG	27.756%	82,945	
Hydro Depreciation Expense	403HP	3	8,602,183	SG-P	27.756%	2,387,585	
Hydro Depreciation Expense	403HP	3	1,430,755	SG-U	27.756%	397,114	
Solar Depreciation Expense	403XP	3	125,023	OR	100.000%	125,023	
Solar Depreciation Expense	403XP	3	13,700	UT	0.000%	-	
Wind Depreciation Expense	403WP	3	81,456,779	SG	27.756%	22,608,797	
Renewable Depreciation Expense	403RP	3	507,554	SG	27.756%	140,875	
Other Depreciation Expense	403OP	3	(27,735)	SG	27.756%	(7,698)	
Other Depreciation Expense	403OP	3	(86,722,877)	SG	27.756%	(24,070,433)	
Other Depreciation Expense	403OP	3	(86)	OR	100.000%	(86)	
Other Depreciation Expense	403OP	3	(13,956)	UT	0.000%	-	
Transmission Depreciation Expense	403TP	3	3,483,017	OR	100.000%	3,483,017	
Transmission Depreciation Expense	403TP	3	(241,782)	SG	27.756%	(67,108)	
Transmission Depreciation Expense	403TP	3	(380,355)	SG	27.756%	(105,570)	
Transmission Depreciation Expense	403TP	3	38,108,240	SG	27.756%	10,577,161	
Transmission Depreciation Expense	403TP	3	1,001,441	OTHER	0.000%	-	
Distribution Depreciation Expense	403360	3	478,288	Situs	100.000%	121,413	
Distribution Depreciation Expense	403361	3	911,491	Situs	100.000%	231,381	
Distribution Depreciation Expense	403362	3	7,576,028	Situs	100.000%	1,923,170	
Distribution Depreciation Expense	403363	3	1,225,064	Situs	100.000%	310,982	
Distribution Depreciation Expense	403364	3	10,792,485	Situs	100.000%	2,739,665	
Distribution Depreciation Expense	403365	3	6,934,034	Situs	100.000%	1,760,200	
Distribution Depreciation Expense	403366	3	3,218,704	Situs	100.000%	817,066	
Distribution Depreciation Expense	403367	3	7,410,809	Situs	100.000%	1,881,229	
Distribution Depreciation Expense	403368	3	10,188,908	Situs	100.000%	2,586,447	
Distribution Depreciation Expense	403369	3	6,546,257	Situs	100.000%	1,661,763	
Distribution Depreciation Expense	403370	3	1,879,643	Situs	100.000%	477,146	
Distribution Depreciation Expense	403371	3	51,742	Situs	100.000%	13,135	
Distribution Depreciation Expense	403372	3	-	Situs	100.000%	-	
Distribution Depreciation Expense	403373	3	388,852	Situs	100.000%	98,710	
Distribution Depreciation Expense	403363	3	474,115.45	SNPD	25.578%	121,270	
Distribution Depreciation Expense	403362	3	(1,463)	SG	27.756%	(406)	
Distribution Depreciation Expense	403362	3	2,576,133	OTHER	0.000%	-	
General Depreciation Expense	403GP	3	(180,619)	CA	0.000%	-	
General Depreciation Expense	403GP	3	(1,642,388)	OR	100.000%	(1,642,388)	
General Depreciation Expense	403GP	3	(351,245)	WA	0.000%	-	
General Depreciation Expense	403GP	3	(666,232)	WYP	0.000%	-	
General Depreciation Expense	403GP	3	(1,567,809)	UT	0.000%	-	
General Depreciation Expense	403GP	3	(309,086)	ID	0.000%	-	
General Depreciation Expense	403GP	3	(156,998)	WYU	0.000%	-	
General Depreciation Expense	403GP	3	(1,129)	SG	27.756%	(313)	
General Depreciation Expense	403GP	3	(7,140)	SG	27.756%	(1,982)	
General Depreciation Expense	403GP	3	(4,776,074)	SG	27.756%	(1,325,627)	
General Depreciation Expense	403GP	3	27,621,269	SO	27.909%	7,708,790	
General Depreciation Expense	403GP	3	(920)	SG	27.756%	(255)	
General Depreciation Expense	403GP	3	2,157,883	CN	30.140%	650,381	
General Depreciation Expense	403GP	3	(4,940)	SE	26.823%	(1,325)	
			132,160,242			58,144,991	6.1.2

Description of Adjustment:

This adjustment reflects the incremental depreciation expense that is calculated on the plant additions included in this filing in adjustment 8.5. The 2027 depreciation and amortization expense for the test period are calculated by applying the current composite depreciation and amortization rates to the monthly 2027 projected plant balances.

PacifiCorp
Oregon General Rate Case - December 2027
Amortization Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Intangible Amortization	404IP	3	-	CA	0.000%	-	
Intangible Amortization	404IP	3	(6,104,294)	CN	30.140%	(1,839,819)	
Intangible Amortization	404IP	3	(78,646)	SG	27.756%	(21,829)	
Intangible Amortization	404IP	3	-	ID	0.000%	-	
Intangible Amortization	404IP	3	(91)	OR	100.000%	(91)	
Intangible Amortization	404IP	3	(986)	SE	26.823%	(265)	
Intangible Amortization	404IP	3	(3,318,057)	SG	27.756%	(920,946)	
Intangible Amortization	404IP	3	(14,739)	SG-P	27.756%	(4,091)	
Intangible Amortization	404IP	3	(8,736)	SG-U	27.756%	(2,425)	
Intangible Amortization	404IP	3	(1,108)	SG	27.756%	(307)	
Intangible Amortization	404IP	3	(20,134,706)	SO	27.909%	(5,619,373)	
Intangible Amortization	404IP	3	(2,461)	UT	0.000%	-	
Intangible Amortization	404IP	3	(68)	WA	0.000%	-	
Intangible Amortization	404IP	3	(10,362)	WYP	0.000%	-	
Intangible Amortization	404IP	3	-	WYU	0.000%	-	
Hydro Amortization	404HP	3	-	SG	27.756%	-	
Hydro Amortization	404HP	3	-	SG	27.756%	-	
Hydro Amortization	404HP	3	-	SG	27.756%	-	
Hydro Amortization	404HP	3	0	SG-P	27.756%	0	
Solar Plant	404XP	3	(46,959)	OR	100.000%	(46,959)	
Solar Plant	404XP	3	-	UT	0.000%	-	
Solar Plant	404XP	3	-	SG	27.756%	-	
Solar Plant	404XP	3	-	OTHER	0.000%	-	
Wind Plant	404WP	3	-	OR	100.000%	-	
Wind Plant	404WP	3	-	UT	0.000%	-	
Wind Plant	404WP	3	-	SG	27.756%	-	
Wind Plant	404WP	3	-	OTHER	0.000%	-	
Renewable Plant	404RP	3	-	OR	100.000%	-	
Renewable Plant	404RP	3	-	UT	0.000%	-	
Renewable Plant	404RP	3	-	SG	27.756%	-	
Renewable Plant	404RP	3	-	OTHER	0.000%	-	
Other Amortization	404OP	3	(55,338)	OR	100.000%	(55,338)	
General Amortization	404GP	3	(3,437)	CA	0.000%	-	
General Amortization	404GP	3	-	CN	30.140%	-	
General Amortization	404GP	3	-	ID	0.000%	-	
General Amortization	404GP	3	(76)	OR	100.000%	(76)	
General Amortization	404GP	3	(154,086)	SO	27.909%	(43,004)	
General Amortization	404GP	3	-	UT	0.000%	-	
General Amortization	404GP	3	(6,365)	WA	0.000%	-	
General Amortization	404GP	3	(0)	WYP	0.000%	-	
General Amortization	404GP	3	-	WYU	0.000%	-	
			(29,940,516)			(8,554,522)	6.1.4
Total Adjustment			102,219,726			49,590,469	6.1.4

Description of Adjustment:

This adjustment reflects the incremental depreciation expense that is calculated on the plant additions included in this filing in adjustment 8.5. The 2027 depreciation and amortization expense for the test period are calculated by applying the current composite depreciation and amortization rates to the monthly 2027 projected plant balances.

PacifiCorp
Oregon General Rate Case - December 2027
Depreciation and Amortization Expense Summary

Description	Account	2020P Factor	12 ME June 2025 Expense	Test Period Expense	Adjustment to Test Period
DEPRECIATION EXPENSE					
Steam Production Plant:					
Pre-merger Pacific	403SP	SG	49,499,812	50,582,921	1,083,109
Pre-merger Utah	403SP	SG	36,828,336	50,932,353	14,104,017
Post-merger	403SP	SG	269,290,613	331,458,573	62,167,960
Oregon	403SP	OR	-	-	-
Washington	403SP	WA	-	-	-
California	403SP	CA	-	-	-
Utah	403SP	UT	-	-	-
Idaho	403SP	ID	-	-	-
Eastern Wyoming	403SP	WYP	-	-	-
Western Wyoming	403SP	WYU	-	-	-
Post-merger	403SP	SG	-	-	-
Post-merger	403SP	OTHER	77,177,362	-	(77,177,362)
Total Steam Plant			432,796,124	432,973,848	177,724
Hydro Production Plant:					
Pre-merger Pacific	403HP	SG	349,486	4,000,962	3,651,476
Pre-merger Utah	403HP	SG	1,323,707	1,248,344	(75,363)
Post-merger	403HP	SG	288,077	586,919	298,842
Post-merger	403HP	SG-P	22,499,567	31,101,750	8,602,183
Post-merger	403HP	SG-U	8,058,343	9,489,097	1,430,755
Total Hydro Plant			32,519,180	46,427,073	13,907,893
Solar Production Plant:					
Oregon	403XP	OR	1,859	126,881	125,023
Utah	403XP	UT	11,690	25,390	13,700
Post-merger	403XP	SG	-	-	-
System	403XP	OTHER	-	-	-
Total Solar Plant			13,548	152,271	138,722
Wind Production Plant:					
Oregon	403WP	OR	-	-	-
Utah	403WP	UT	-	-	-
Post-merger	403WP	SG	72,060,853	153,517,632	81,456,779
System	403WP	OTHER	-	-	-
Total Wind Plant			72,060,853	153,517,632	81,456,779
Renewable Production Plant:					
Oregon	403RP	OR	-	-	-
Utah	403RP	UT	-	-	-
Post-merger	403RP	SG	2,516,034	3,023,588	507,554
System	403RP	OTHER	-	-	-
Total Renewable Plant			2,516,034	3,023,588	507,554
Other Production Plant:					
Pre-merger Pacific	403OP	DGU	-	-	-
Post-merger	403OP	SG	4,294,749	4,267,014	(27,735)
Post-merger	403OP	SG	157,955,047	71,232,170	(86,722,877)
Oregon	403OP	OR	86	-	(86)
Utah	403OP	UT	13,956	-	(13,956)
System	403OP	OTHER	-	-	-
Total Other Plant			162,263,838	75,499,184	(86,764,654)
Transmission Plant:					
California	403TP	CA	-	-	-
Oregon	403TP	OR	-	3,483,017	3,483,017
Washington	403TP	WA	-	-	-
Wyoing	403TP	WYP	-	-	-
Wyoming	403TP	WYU	-	-	-
Utah	403TP	UT	-	-	-
Idaho	403TP	ID	-	-	-
Pre-merger Pacific	403TP	SG	8,200,352	7,958,571	(241,782)
Pre-merger Utah	403TP	SG	10,372,739	9,992,384	(380,355)
Post-merger	403TP	SG	161,834,449	199,942,689	38,108,240
System	403TP	OTHER	(1,001,441)	-	1,001,441
Total Transmission Plant			179,406,099	221,376,660	41,970,561

PacifiCorp
Oregon General Rate Case - December 2027
Depreciation and Amortization Expense Summary

Description	Account	2020P Factor	12 ME June 2025 Expense	Test Period Expense	Adjustment to Test Period
Distribution Plant:					
California	403364	CA	15,813,224	23,299,947	7,486,723
Oregon	403364	OR	68,738,751	83,361,056	14,622,305
Washington	403364	WA	18,293,292	19,671,480	1,378,188
Eastern Wyoming	403364	WYP	21,548,433	25,736,788	4,188,355
Utah	403364	UT	108,767,164	136,258,385	27,491,222
Idaho	403364	ID	12,383,516	14,468,467	2,084,951
Western Wyoming	403364	WYU	4,126,773	4,477,332	350,560
Pre-merger Pacific	403363	SG	-	-	-
Pre-merger Utah	403363	SG	-	-	-
System	403363	SNPD	612,423.28	1,086,539	474,115.45
System	403363	CN	-	-	-
System	403363	SO	-	-	-
System	403362	SG	1,463	-	(1,463)
System	403362	OTHER	(2,576,133)	-	2,576,133
Total Distribution Plant			247,708,906	308,359,995	60,651,089
Energy Storage Plant:					
California	403ES	CA	-	-	-
Oregon	403ES	OR	-	-	-
Washington	403ES	WA	-	-	-
Eastern Wyoming	403ES	WYP	-	-	-
Utah	403ES	UT	-	-	-
Idaho	403ES	ID	-	-	-
Western Wyoming	403ES	WYU	-	-	-
System	403ES	CN	-	-	-
System	403ES	SNPD	-	-	-
System	403ES	SG	-	-	-
System	403ES	SO	-	-	-
System	403ES	OTHER	-	-	-
Total Energy Storage Plant			-	-	-
General Plant:					
California	403GP	CA	354,934	174,315	(180,619)
Oregon	403GP	OR	3,788,995	2,146,608	(1,642,388)
Washington	403GP	WA	836,612	485,367	(351,245)
Eastern Wyoming	403GP	WYP	1,545,905	879,673	(666,232)
Utah	403GP	UT	4,678,296	3,110,487	(1,567,809)
Idaho	403GP	ID	820,269	511,184	(309,086)
Western Wyoming	403GP	WYU	339,566	182,567	(156,998)
Pre-merger Pacific	403GP	SG	6,539	5,410	(1,129)
Pre-merger Utah	403GP	SG	28,748	21,608	(7,140)
Post-merger	403GP	SG	7,446,886	2,670,813	(4,776,074)
System	403GP	SO	40,455,878	68,077,147	27,621,269
System	403GP	SG	6,826	5,906	(920)
System	403GP	SG	-	-	-
System	403GP	SNPD	-	-	-
Customer Service	403GP	CN	4,814,596	6,972,479	2,157,883
Fuel Related	403GP	SE	100,598	95,658	(4,940)
Total General Plant			65,224,647	85,339,221	20,114,574
Mining Plant:					
Coal Mine	403MP	SE	-	-	-
Total Mining Plant			-	-	-
Total Depreciation Expense			1,194,509,229	1,326,669,471	**132,160,242**

PacifiCorp
Oregon General Rate Case - December 2027
Depreciation and Amortization Expense Summary

Description	Account	2020P Factor	12 ME June 2025 Expense	Test Period Expense	Adjustment to Test Period
Amortization Expense					
Intangible Plant:					
California	404IP	CA	-	-	-
Customer Service	404IP	CN	6,104,294	-	(6,104,294)
Pre-merger Pacific	404IP	SG	78,646	-	(78,646)
Idaho	404IP	ID	-	-	-
Oregon	404IP	OR	8,929	8,838	(91)
Fuel Related	404IP	SE	986	-	(986)
Post-merger	404IP	SG	8,820,129	5,502,072	(3,318,057)
Hydro Relicensing	404IP	SG-P	2,697,714	2,682,975	(14,739)
Hydro Relicensing	404IP	SG-U	251,815	243,078	(8,736)
Pre-merger Utah	404IP	SG	12,470	11,363	(1,108)
General Office	404IP	SO	20,134,706	-	(20,134,706)
Utah	404IP	UT	96,615	94,153	(2,461)
Washington	404IP	WA	68	-	(68)
Eastern Wyoming	404IP	WYP	67,672	57,310	(10,362)
Western Wyoming	404IP	WYU	-	-	-
Total Intangible Plant			38,274,045	8,599,790	(29,674,255)
Hydro Production Plant:					
Pre-merger Pacific	404HP	SG	-	-	-
Pre-merger Utah	404HP	SG	-	-	-
Post-merger	404HP	SG	-	-	-
Post-merger Pacific	404HP	SG-P	314,732	314,732	0
Post-merger Utah	404HP	SG-U	314,732	314,732	0
Total Hydro Plant					
Solar Production Plant:					
Oregon	404XP	OR	46,959	-	(46,959)
Utah	404XP	UT	-	-	-
Post-merger	404XP	SG	-	-	-
System	404XP	OTHER	-	-	-
Total Solar Plant			46,959	-	(46,959)
Wind Production Plant:					
Oregon	404WP	OR	-	-	-
Utah	404WP	UT	-	-	-
Post-merger	404WP	SG	-	-	-
System	404WP	OTHER	-	-	-
Total Wind Plant			-	-	-
Renewable Production Plant:					
Oregon	404RP	OR	-	-	-
Utah	404RP	UT	-	-	-
Post-merger	404RP	SG	-	-	-
System	404RP	OTHER	-	-	-
Total Renewable Plant			-	-	-
Other Production Plant:					
Oregon	404OP	OR	55,338	-	(55,338)
Total Other Plant			55,338	-	(55,338)
General Plant:					
California	404GP	CA	3,437	-	(3,437)
General Office	404GP	CN	-	-	-
Idaho	404GP	ID	-	-	-
Oregon	404GP	OR	75,458	75,382	(76)
General Office	404GP	SO	188,266	34,180	(154,086)
Utah	404GP	UT	-	-	-
Washington	404GP	WA	107,861	101,497	(6,365)
Eastern Wyoming	404GP	WYP	3,464	3,464	(0)
Western Wyoming	404GP	WYU	-	-	-
Total General Plant			378,486	214,522	(163,964)
Total Amortization Expense			39,069,560	9,129,044	**(29,940,516)**
					Ref 6.1.1
			1,233,578,789	1,335,798,515	**102,219,726**
Total Depreciation & Amortization Expense				**Ref. 6.1.48**	**Ref 6.1.1**

PacifiCorp
Oregon General Rate Case - December 2027
Jun 2025 - Dec 2027 Depreciation & Amortization Expense

Description	Account	2020P Factor	June 2025 Rate	Adjusted EPIS Balance Jun 2025	Depreciation Expense Jun 2025	Adjustments	Adjusted EPIS Balance Jul 2025	Depreciation Expense Jul 2025	Adjustments	Adjusted EPIS Balance Aug 2025	Depreciation Expense Aug 2025
DEPRECIATION EXPENSE											
Steam Production Plant:											
Pre-merger Pacific	403SP	SG	5.141%	987,592,112	4,231,276	(181,436)	987,410,676	4,230,888	(181,436)	987,229,240	4,230,110
Pre-merger Utah	403SP	SG	5.053%	1,014,704,747	4,272,673	(325,979)	1,014,378,767	4,271,987	(325,979)	1,014,052,788	4,270,614
Post-merger	403SP	SG	6.360%	5,111,725,243	27,092,480	1,290,119	5,113,015,362	27,095,899	2,699,061	5,115,714,424	27,106,470
Oregon	403SP	OR	0.000%	-	-	-	-	-	-	-	-
Washington	403SP	WA	0.000%	-	-	-	-	-	-	-	-
California	403SP	CA	0.000%	-	-	-	-	-	-	-	-
Utah	403SP	UT	0.000%	-	-	-	-	-	-	-	-
Idaho	403SP	ID	0.000%	-	-	-	-	-	-	-	-
Eastern Wyoming	403SP	WYP	0.000%	-	-	-	-	-	-	-	-
Western Wyoming	403SP	WYU	0.000%	-	-	-	-	-	-	-	-
Post-merger	403SP	SG	0.000%	1,266,851	-	-	1,266,851	-	-	1,266,851	-
Post-merger	403SP	OTHER	0.000%	-	-	-	-	-	-	-	-
Total Steam Plant				7,115,288,953	35,596,429	782,704	7,116,071,657	35,598,773	2,191,646	7,118,263,303	35,607,195
Hydro Production Plant:											
Pre-merger Pacific	403HP	SG	2.311%	173,759,313	334,588	(29,571)	173,729,743	334,559	(29,571)	173,700,172	334,502
Pre-merger Utah	403HP	SG	3.187%	39,567,052	105,077	(19,142)	39,547,910	105,052	(19,142)	39,528,768	105,001
Post-merger	403HP	SG	4.498%	13,047,000	48,910	-	13,047,000	48,910	-	13,047,000	48,910
Post-merger	403HP	SG-P	3.538%	734,920,500	2,166,836	(80,833)	734,839,667	2,166,717	1,834,306	736,673,973	2,169,301
Post-merger	403HP	SG-U	4.611%	168,988,088	649,333	(73,653)	168,914,435	649,191	(73,653)	168,840,782	648,908
Total Hydro Plant				1,130,281,953	3,304,743	(203,198)	1,130,078,755	3,304,429	1,711,941	1,131,790,696	3,306,623
Solar Production Plant:											
Oregon	403XP	OR	13.803%	770,480	8,863	78,644	849,123	9,315	-	849,123	9,767
Utah	403XP	UT	4.546%	561,017	2,125	(123)	560,893	2,125	(123)	560,770	2,125
Post-merger	403XP	SG	0.000%	56,322	-	-	56,322	-	-	56,322	-
System	403XP	OTHER	0.000%	-	-	-	-	-	-	-	-
Total Solar Plant				1,387,818	10,988	78,521	1,466,339	11,440	(123)	1,466,216	11,892
Wind Production Plant:											
Oregon	403WP	OR	0.000%	-	-	-	-	-	-	-	-
Utah	403WP	UT	0.000%	-	-	-	-	-	-	-	-
Post-merger	403WP	SG	3.991%	3,805,799,747	12,657,768	(49,251)	3,805,750,496	12,657,686	147,415	3,805,897,911	12,657,850
System	403WP	OTHER	0.000%	-	-	-	-	-	-	-	-
Total Wind Plant				3,805,799,747	12,657,768	(49,251)	3,805,750,496	12,657,686	147,415	3,805,897,911	12,657,850
Renewable Production Plant:											
Oregon	403RP	OR	0.000%	-	-	-	-	-	-	-	-
Utah	403RP	UT	0.000%	-	-	-	-	-	-	-	-
Post-merger	403RP	SG	1.896%	157,826,749	249,350	13,715	157,840,464	249,361	13,715	157,854,179	249,383
System	403RP	OTHER	0.000%	-	-	-	-	-	-	-	-
Total Renewable Plant				157,826,749	249,350	13,715	157,840,464	249,361	13,715	157,854,179	249,383

PacifiCorp
Oregon General Rate Case - December 2027
Jun 2025 - Dec 2027 Depreciation & Amortization Expense

Description	Account	2020P Factor	June 2025 Rate	Adjusted EPIS Balance Jun 2025	Depreciation Expense Jun 2025	Adjustments	Adjusted EPIS Balance Jul 2025	Depreciation Expense Jul 2025	Adjustments	Adjusted EPIS Balance Aug 2025	Depreciation Expense Aug 2025
Other Production Plant:											
Pre-merger Pacific	403OP	DGU	0.000%	235,129	-	-	235,129	-	-	235,129	-
Post-merger	403OP	SG	4.832%	88,883,413	357,896	(29,730)	88,853,683	357,836	(29,730)	88,823,953	357,716
Post-merger	403OP	SG	3.509%	1,974,191,377	5,772,465	(2,051,360)	1,972,140,016	5,769,466	(2,324,668)	1,969,815,349	5,763,068
Oregon	403OP	OR	0.000%	-	-	-	-	-	-	-	-
Utah	403OP	UT	0.000%	-	-	-	-	-	-	-	-
System	403OP	OTHER	0.000%	-	-	-	-	-	-	-	-
Total Other Plant				2,063,309,919	6,130,361	(2,081,090)	2,061,228,828	6,127,302	(2,354,398)	2,058,874,431	6,120,784
Transmission Plant:											
California	403TP	CA	1.770%	-	-	-	-	-	-	-	-
Oregon	403TP	OR	1.770%	-	-	(44,853)	(44,853)	(33)	(20,816)	(65,669)	(82)
Washington	403TP	WA	1.770%	-	-	-	-	-	-	-	-
Wyoing	403TP	WYP	1.770%	-	-	-	-	-	-	-	-
Wyoming	403TP	WYU	1.770%	-	-	-	-	-	-	-	-
Utah	403TP	UT	1.770%	-	-	-	-	-	-	-	-
Idaho	403TP	ID	1.770%	-	-	-	-	-	-	-	-
Pre-merger Pacific	403TP	SG	1.697%	472,345,011	668,164	(169,652)	472,175,360	668,044	(169,652)	472,005,708	667,804
Pre-merger Utah	403TP	SG	1.668%	604,989,761	841,166	(295,257)	604,694,504	840,960	(295,257)	604,399,247	840,550
Post-merger	403TP	SG	1.770%	10,372,730,659	15,300,332	15,445,250	10,388,175,909	15,311,723	49,954,766	10,438,130,675	15,359,957
System	403TP	OTHER	0.000%	-	-	-	-	-	-	-	-
Total Transmission Plant				11,450,065,431	16,809,661	14,935,488	11,465,000,919	16,820,694	49,469,041	11,514,469,960	16,868,229
Distribution Plant:											
California	403364	CA	2.814%	590,906,802	1,385,725	2,819,701	593,726,503	1,389,031	8,237,494	601,963,997	1,401,996
Oregon	403364	OR	2.340%	3,137,515,987	6,117,223	14,551,772	3,152,067,758	6,131,409	14,128,306	3,166,196,065	6,159,368
Washington	403364	WA	2.626%	711,585,848	1,557,213	629,126	712,214,974	1,557,902	209,221	712,424,195	1,558,819
Eastern Wyoming	403364	WYP	2.723%	806,826,853	1,830,741	1,810,409	808,637,262	1,832,795	1,982,811	810,620,073	1,837,098
Utah	403364	UT	2.572%	4,430,786,259	9,496,549	44,904,753	4,475,691,012	9,544,671	53,363,138	4,529,054,150	9,649,980
Idaho	403364	ID	2.602%	497,264,321	1,078,331	1,533,156	498,797,477	1,079,993	2,296,549	501,094,026	1,084,146
Western Wyoming	403364	WYU	2.707%	166,489,437	375,598	(53,455)	166,435,982	375,538	(53,455)	166,382,527	375,417
Pre-merger Pacific	403363	SG	0.000%	-	-	-	-	-	-	-	-
Pre-merger Utah	403363	SG	0.000%	-	-	-	-	-	-	-	-
System	403363	SNPD	2.880%	35,847,239	86,026	-	35,847,239	86,026	-	35,847,239	86,026
System	403363	CN	0.000%	10,802,634	-	-	10,802,634	-	-	10,802,634	-
System	403363	SO	0.000%	-	-	-	-	-	-	-	-
System	403362	SG	0.000%	-	-	-	-	-	-	-	-
System	403362	OTHER	0.000%	-	-	-	-	-	-	-	-
Total Distribution Plant				10,388,025,380	21,927,406	66,195,462	10,454,220,842	21,997,364	80,164,064	10,534,384,906	22,152,850
Energy Storage Plant:											
California	403ES	CA	0.000%	-	-	-	-	-	-	-	-
Oregon	403ES	OR	0.000%	-	-	-	-	-	-	-	-
Washington	403ES	WA	0.000%	-	-	-	-	-	-	-	-
Eastern Wyoming	403ES	WYP	0.000%	-	-	-	-	-	-	-	-
Utah	403ES	UT	0.000%	-	-	-	-	-	-	-	-
Idaho	403ES	ID	0.000%	-	-	-	-	-	-	-	-
Western Wyoming	403ES	WYU	0.000%	-	-	-	-	-	-	-	-
System	403ES	CN	0.000%	-	-	-	-	-	-	-	-
System	403ES	SNPD	0.000%	-	-	-	-	-	-	-	-
System	403ES	SG	0.000%	-	-	-	-	-	-	-	-
System	403ES	SO	0.000%	-	-	-	-	-	-	-	-
System	403ES	OTHER	0.000%	-	-	-	-	-	-	-	-
Total Energy Storage Plant				-	-	-	-	-	-	-	-

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General Plant:											
California	403GP	CA	1.093%	16,195,923	14,751	(50,275)	16,145,648	14,728	(50,275)	16,095,373	14,683
Oregon	403GP	OR	1.416%	156,055,515	184,093	(39,463)	156,016,053	184,070	(424,770)	155,591,282	183,796
Washington	403GP	WA	1.384%	35,643,163	41,122	(100,842)	35,542,322	41,064	(100,842)	35,441,480	40,947
Eastern Wyoming	403GP	WYP	1.228%	66,812,112	68,396	(107,634)	66,704,477	68,341	581,302	67,285,779	68,583
Utah	403GP	UT	1.411%	209,705,999	246,606	3,579,851	213,285,850	248,711	724,531	214,010,381	251,242
Idaho	403GP	ID	1.184%	42,231,560	41,669	94,137	42,325,697	41,716	(5,436)	42,320,261	41,760
Western Wyoming	403GP	WYU	1.369%	13,702,519	15,627	(17,563)	13,684,956	15,617	(17,563)	13,667,393	15,597
Pre-merger Pacific	403GP	SG	1.134%	655,748	620	(8,667)	647,081	616	(8,667)	638,414	608
Pre-merger Utah	403GP	SG	1.265%	2,273,454	2,396	(27,378)	2,246,076	2,381	(27,378)	2,218,697	2,352
Post-merger	403GP	SG	2.586%	118,805,520	256,022	(752,692)	118,052,827	255,211	(752,692)	117,300,135	253,589
System	403GP	SO	6.377%	957,394,460	5,087,750	(1,472,253)	955,922,207	5,083,838	(828,888)	955,093,319	5,077,723
System	403GP	SG	3.174%	192,889	510	(331)	192,557	510	(331)	192,226	509
System	403GP	SG	0.000%	-	-	-	-	-	-	-	-
System	403GP	SNPD	0.000%	-	-	-	-	-	-	-	-
Customer Service	403GP	CN	2.941%	238,683,088	584,963	(77,602)	238,605,486	584,867	(77,602)	238,527,884	584,677
Fuel Related	403GP	SE	3.761%	2,813,277	8,816	(13,073)	2,800,205	8,796	(13,073)	2,787,132	8,755
Total General Plant				1,861,165,227	6,553,341	1,006,214	1,862,171,441	6,550,466	(1,001,684)	1,861,169,756	6,544,821
Mining Plant:											
Coal Mine	403MP	SE	0.000%	1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Mining Plant				1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Depreciation Expense				37,974,974,078	103,240,048	80,678,564	38,055,652,642	103,317,516	130,341,617	38,185,994,259	103,519,627
Amortization Expense											
Intangible Plant:											
California	404IP	CA	0.000%	472,341	-	(147)	472,194	-	(147)	472,047	-
Customer Service	404IP	CN	0.000%	-	-	(154,776)	(154,776)	-	(154,776)	(309,553)	-
Pre-merger Pacific	404IP	SG	0.000%	-	-	-	-	-	-	-	-
Idaho	404IP	ID	0.000%	4,356,591	-	(243)	4,356,348	-	(243)	4,356,106	-
Oregon	404IP	OR	0.192%	4,601,718	737	(225)	4,601,493	737	(225)	4,601,267	737
Fuel Related	404IP	SE	0.000%	-	-	-	-	-	-	-	-
Post-merger	404IP	SG	2.805%	202,684,129	473,725	(315,712)	202,368,418	473,356	(315,712)	202,052,706	472,618
Hydro Relicensing	404IP	SG-P	2.593%	103,455,075	223,581	-	103,455,075	223,581	-	103,455,075	223,581
Hydro Relicensing	404IP	SG-U	2.502%	10,024,217	20,898	(14,920)	10,009,296	20,883	(14,920)	9,994,376	20,851
Pre-merger Utah	404IP	SG	2.611%	477,596	1,039	(2,057)	475,540	1,037	(2,057)	473,483	1,032
General Office	404IP	SO	0.000%	-	-	(677,200)	(677,200)	-	(677,200)	(1,354,399)	-
Utah	404IP	UT	1.266%	7,444,448	7,855	(404)	7,444,044	7,855	(404)	7,443,640	7,854
Washington	404IP	WA	0.000%	2,021,245	-	(252)	2,020,993	-	(252)	2,020,741	-
Eastern Wyoming	404IP	WYP	1.117%	5,268,401	4,904	(6,676)	5,261,725	4,901	(6,676)	5,255,049	4,895
Western Wyoming	404IP	WYU	0.000%	-	-	-	-	-	-	-	-
Total Intangible Plant				340,805,762	732,740	(1,172,612)	339,633,150	732,350	(1,172,612)	338,460,538	731,570
Hydro Production Plant:											
Pre-merger Pacific	404HP	SG	0.000%	-	-	-	-	-	-	-	-
Pre-merger Utah	404HP	SG	0.000%	-	-	-	-	-	-	-	-
Post-merger	404HP	SG	0.000%	-	-	-	-	-	-	-	-
Post-merger Pacific	404HP	SG-P	2.131%	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228
Post-merger Utah	404HP	SG-U	0.000%	-	-	-	-	-	-	-	-
Total Hydro Plant				14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228

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Solar Production Plant:											
Oregon	404XP	OR	0.000%	-	-	-	-	-	-	-	-
Utah	404XP	UT	0.000%	-	-	-	-	-	-	-	-
Post-merger	404XP	SG	0.000%	-	-	-	-	-	-	-	-
System	404XP	OTHER	0.000%	-	-	-	-	-	-	-	-
Total Solar Plant				-	-	-	-	-	-	-	-
Wind Production Plant:											
Oregon	404WP	OR	0.000%	-	-	-	-	-	-	-	-
Utah	404WP	UT	0.000%	-	-	-	-	-	-	-	-
Post-merger	404WP	SG	0.000%	-	-	-	-	-	-	-	-
System	404WP	OTHER	0.000%	-	-	-	-	-	-	-	-
Total Wind Plant				-	-	-	-	-	-	-	-
Renewable Production Plant:											
Oregon	404RP	OR	0.000%	-	-	-	-	-	-	-	-
Utah	404RP	UT	0.000%	-	-	-	-	-	-	-	-
Post-merger	404RP	SG	0.000%	-	-	-	-	-	-	-	-
System	404RP	OTHER	0.000%	-	-	-	-	-	-	-	-
Total Renewable Plant				-	-	-	-	-	-	-	-
Other Production Plant:											
Oregon	404OP	OR	0.000%	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-
General Plant:											
California	404GP	CA	0.000%	513,307	-	-	513,307	-	-	513,307	-
General Office	404GP	CN	0.000%	-	-	-	-	-	-	-	-
Idaho	404GP	ID	0.000%	333,771	-	-	333,771	-	-	333,771	-
Oregon	404GP	OR	1.325%	5,690,473	6,282	-	5,690,473	6,282	-	5,690,473	6,282
General Office	404GP	SO	1.556%	2,196,886	2,848	-	2,196,886	2,848	-	2,196,886	2,848
Utah	404GP	UT	0.000%	33,127	-	-	33,127	-	-	33,127	-
Washington	404GP	WA	3.944%	2,573,715	8,458	-	2,573,715	8,458	-	2,573,715	8,458
Eastern Wyoming	404GP	WYP	0.073%	4,767,976	289	-	4,767,976	289	-	4,767,976	289
Western Wyoming	404GP	WYU	0.000%	-	-	-	-	-	-	-	-
Total General Plant				16,109,254	17,877	-	16,109,254	17,877	-	16,109,254	17,877
Total Amortization Expense				371,683,113	776,844	(1,172,612)	370,510,501	776,454	(1,172,612)	369,337,890	775,674
Total Depreciation & Amortization Expense				38,346,657,191	104,016,892	79,505,952	38,426,163,144	104,093,970	129,169,005	38,555,332,149	104,295,302

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DEPRECIATION EXPENSE												
Steam Production Plant:												
Pre-merger Pacific	403SP	SG	5.141%	(181,436)	987,047,804	4,229,333	(181,436)	986,866,368	4,228,556	(181,436)	986,684,932	4,227,778
Pre-merger Utah	403SP	SG	5.053%	(325,979)	1,013,726,808	4,269,242	(325,979)	1,013,400,829	4,267,869	(325,979)	1,013,074,849	4,266,496
Post-merger	403SP	SG	6.360%	(721,930)	5,114,992,494	27,111,710	(896,681)	5,114,095,814	27,107,420	1,270,513	5,115,366,327	27,108,411
Oregon	403SP	OR	0.000%	-	-	-	-	-	-	-	-	-
Washington	403SP	WA	0.000%	-	-	-	-	-	-	-	-	-
California	403SP	CA	0.000%	-	-	-	-	-	-	-	-	-
Utah	403SP	UT	0.000%	-	-	-	-	-	-	-	-	-
Idaho	403SP	ID	0.000%	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403SP	WYP	0.000%	-	-	-	-	-	-	-	-	-
Western Wyoming	403SP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403SP	SG	0.000%	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-
Post-merger	403SP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Steam Plant				(1,229,345)	7,117,033,958	35,610,284	(1,404,096)	7,115,629,862	35,603,845	763,098	7,116,392,959	35,602,686
Hydro Production Plant:												
Pre-merger Pacific	403HP	SG	2.311%	(29,571)	173,670,602	334,446	(29,571)	173,641,031	334,389	(29,571)	173,611,461	334,332
Pre-merger Utah	403HP	SG	3.187%	(19,142)	39,509,627	104,950	(19,142)	39,490,485	104,899	(19,142)	39,471,344	104,848
Post-merger	403HP	SG	4.498%	-	13,047,000	48,910	-	13,047,000	48,910	-	13,047,000	48,910
Post-merger	403HP	SG-P	3.538%	1,516,822	738,190,795	2,174,242	436,559	738,627,355	2,177,121	11,445,015	750,072,369	2,194,637
Post-merger	403HP	SG-U	4.611%	38,679	168,879,461	648,841	247,818	169,127,280	649,392	6,777,787	175,905,067	662,889
Total Hydro Plant				1,506,790	1,133,297,486	3,311,388	635,665	1,133,933,151	3,314,711	18,174,090	1,152,107,241	3,345,616
Solar Production Plant:												
Oregon	403XP	OR	13.803%	-	849,123	9,767	-	849,123	9,767	-	849,123	9,767
Utah	403XP	UT	4.546%	(123)	560,647	2,124	(123)	560,524	2,124	(123)	560,401	2,123
Post-merger	403XP	SG	0.000%	-	56,322	-	-	56,322	-	-	56,322	-
System	403XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Solar Plant				(123)	1,466,093	11,892	(123)	1,465,969	11,891	(123)	1,465,846	11,891
Wind Production Plant:												
Oregon	403WP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403WP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403WP	SG	3.991%	3,224,693	3,809,122,604	12,663,457	(107,511)	3,809,015,093	12,668,641	(107,511)	3,808,907,582	12,668,283
System	403WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Wind Plant				3,224,693	3,809,122,604	12,663,457	(107,511)	3,809,015,093	12,668,641	(107,511)	3,808,907,582	12,668,283
Renewable Production Plant:												
Oregon	403RP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403RP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403RP	SG	1.896%	13,715	157,867,895	249,404	13,715	157,881,610	249,426	315,278	158,196,888	249,686
System	403RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Renewable Plant				13,715	157,867,895	249,404	13,715	157,881,610	249,426	315,278	158,196,888	249,686

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Other Production Plant:												
Pre-merger Pacific	403OP	DGU	0.000%	-	235,129	-	-	235,129	-	-	235,129	-
Post-merger	403OP	SG	4.832%	(29,730)	88,794,223	357,596	(29,730)	88,764,493	357,477	(29,730)	88,734,763	357,357
Post-merger	403OP	SG	3.509%	(2,385,393)	1,967,429,956	5,756,182	(2,240,763)	1,965,189,194	5,749,419	(99,294)	1,965,089,900	5,745,998
Oregon	403OP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403OP	UT	0.000%	-	-	-	-	-	-	-	-	-
System	403OP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant				(2,415,123)	2,056,459,308	6,113,779	(2,270,493)	2,054,188,816	6,106,896	(129,024)	2,054,059,792	6,103,355
Transmission Plant:												
California	403TP	CA	1.770%	-	-	-	-	-	-	-	-	-
Oregon	403TP	OR	1.770%	(341,161)	(406,830)	(348)	13,363	(393,467)	(590)	-	(393,467)	(580)
Washington	403TP	WA	1.770%	-	-	-	-	-	-	-	-	-
Wyoing	403TP	WYP	1.770%	-	-	-	-	-	-	-	-	-
Wyoming	403TP	WYU	1.770%	-	-	-	-	-	-	-	-	-
Utah	403TP	UT	1.770%	-	-	-	-	-	-	-	-	-
Idaho	403TP	ID	1.770%	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	403TP	SG	1.697%	(169,652)	471,836,056	667,564	(169,652)	471,666,404	667,324	(169,652)	471,496,752	667,084
Pre-merger Utah	403TP	SG	1.668%	(295,257)	604,103,989	840,139	(295,257)	603,808,732	839,729	(295,257)	603,513,475	839,318
Post-merger	403TP	SG	1.770%	90,765,974	10,528,896,649	15,463,742	65,587,148	10,594,483,797	15,579,057	45,903,682	10,640,387,478	15,661,285
System	403TP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Transmission Plant				89,959,904	11,604,429,864	16,971,097	65,135,602	11,669,565,466	17,085,520	45,438,773	11,715,004,239	17,167,106
Distribution Plant:												
California	403364	CA	2.814%	7,733,044	609,697,041	1,420,722	12,800,677	622,497,718	1,444,799	20,776,147	643,273,865	1,484,169
Oregon	403364	OR	2.340%	10,256,707	3,176,452,771	6,183,140	18,771,597	3,195,224,369	6,211,438	15,620,931	3,210,845,300	6,244,965
Washington	403364	WA	2.626%	1,033,888	713,458,083	1,560,179	1,759,387	715,217,470	1,563,235	334,448	715,551,917	1,565,527
Eastern Wyoming	403364	WYP	2.723%	4,616,557	815,236,630	1,844,585	3,876,918	819,113,548	1,854,221	3,654,891	822,768,439	1,862,766
Utah	403364	UT	2.572%	73,064,061	4,602,118,211	9,785,467	100,049,732	4,702,167,943	9,970,985	69,938,194	4,772,106,136	10,153,153
Idaho	403364	ID	2.602%	7,350,146	508,444,172	1,094,605	1,607,826	510,051,998	1,104,318	1,517,229	511,569,227	1,107,707
Western Wyoming	403364	WYU	2.707%	(53,455)	166,329,072	375,297	(53,455)	166,275,617	375,176	(53,455)	166,222,162	375,056
Pre-merger Pacific	403363	SG	0.000%	-	-	-	-	-	-	-	-	-
Pre-merger Utah	403363	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403363	SNPD	2.880%	-	35,847,239	86,026	-	35,847,239	86,026	-	35,847,239	86,026
System	403363	CN	0.000%	-	10,802,634	-	-	10,802,634	-	-	10,802,634	-
System	403363	SO	0.000%	-	-	-	-	-	-	-	-	-
System	403362	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403362	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Distribution Plant				104,000,947	10,638,385,853	22,350,021	138,812,681	10,777,198,534	22,610,199	111,788,385	10,888,986,919	22,879,369
Energy Storage Plant:												
California	403ES	CA	0.000%	-	-	-	-	-	-	-	-	-
Oregon	403ES	OR	0.000%	-	-	-	-	-	-	-	-	-
Washington	403ES	WA	0.000%	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403ES	WYP	0.000%	-	-	-	-	-	-	-	-	-
Utah	403ES	UT	0.000%	-	-	-	-	-	-	-	-	-
Idaho	403ES	ID	0.000%	-	-	-	-	-	-	-	-	-
Western Wyoming	403ES	WYU	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	CN	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SNPD	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SO	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant				-	-	-	-	-	-	-	-	-

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General Plant:												
California	403GP	CA	1.093%	(7,008)	16,088,365	14,657	95,612	16,183,977	14,697	93,904	16,277,881	14,783
Oregon	403GP	OR	1.416%	545,238	156,136,520	183,867	291,886	156,428,407	184,361	253,229	156,681,636	184,683
Washington	403GP	WA	1.384%	(11,344)	35,430,136	40,883	137,836	35,567,973	40,956	134,421	35,702,394	41,113
Eastern Wyoming	403GP	WYP	1.228%	149,742	67,435,522	68,957	147,494	67,583,016	69,109	147,521	67,730,537	69,260
Utah	403GP	UT	1.411%	677,585	214,687,967	252,066	672,829	215,360,796	252,860	602,256	215,963,052	253,610
Idaho	403GP	ID	1.184%	88,758	42,409,019	41,801	87,555	42,496,574	41,888	162,495	42,659,069	42,011
Western Wyoming	403GP	WYU	1.369%	(17,563)	13,649,830	15,577	(17,563)	13,632,268	15,557	(17,563)	13,614,705	15,537
Pre-merger Pacific	403GP	SG	1.134%	(8,667)	629,747	599	(8,667)	621,081	591	(8,667)	612,414	583
Pre-merger Utah	403GP	SG	1.265%	(27,378)	2,191,319	2,324	(27,378)	2,163,941	2,295	(27,378)	2,136,562	2,266
Post-merger	403GP	SG	2.586%	(752,692)	116,547,442	251,967	(752,692)	115,794,750	250,345	(752,692)	115,042,058	248,723
System	403GP	SO	6.377%	6,908,917	962,002,236	5,093,879	5,031,643	967,033,879	5,125,606	10,327,512	977,361,391	5,166,416
System	403GP	SG	3.174%	(331)	191,895	508	(331)	191,563	507	(331)	191,232	506
System	403GP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403GP	SNPD	0.000%	-	-	-	-	-	-	-	-	-
Customer Service	403GP	CN	2.941%	(77,602)	238,450,281	584,487	(77,602)	238,372,679	584,297	(77,602)	238,295,077	584,107
Fuel Related	403GP	SE	3.761%	(13,073)	2,774,059	8,714	(13,073)	2,760,986	8,673	(13,073)	2,747,914	8,632
Total General Plant				7,454,582	1,868,624,339	6,560,285	5,567,550	1,874,191,889	6,591,741	10,824,032	1,885,015,920	6,632,230
Mining Plant:												
Coal Mine	403MP	SE	0.000%	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Mining Plant				-	1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Depreciation Expense				202,516,040	38,388,510,300	103,841,608	206,382,991	38,594,893,291	104,242,869	187,066,997	38,781,960,288	104,660,222
Amortization Expense												
Intangible Plant:												
California	404IP	CA	0.000%	(147)	471,900	-	(147)	471,753	-	(147)	471,605	-
Customer Service	404IP	CN	0.000%	(154,776)	(464,329)	-	(154,776)	(619,106)	-	(154,776)	(773,882)	-
Pre-merger Pacific	404IP	SG	0.000%	-	-	-	-	-	-	-	-	-
Idaho	404IP	ID	0.000%	(243)	4,355,863	-	(243)	4,355,621	-	(243)	4,355,378	-
Oregon	404IP	OR	0.192%	(225)	4,601,042	737	(225)	4,600,817	737	(225)	4,600,591	737
Fuel Related	404IP	SE	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404IP	SG	2.805%	(315,712)	201,736,994	471,880	(315,712)	201,421,282	471,143	(315,712)	201,105,571	470,405
Hydro Relicensing	404IP	SG-P	2.593%	-	103,455,075	223,581	-	103,455,075	223,581	-	103,455,075	223,581
Hydro Relicensing	404IP	SG-U	2.502%	(14,920)	9,979,455	20,820	(14,920)	9,964,535	20,789	(14,920)	9,949,615	20,758
Pre-merger Utah	404IP	SG	2.611%	(2,057)	471,427	1,028	(2,057)	469,370	1,024	(2,057)	467,313	1,019
General Office	404IP	SO	0.000%	(677,200)	(2,031,599)	-	(677,200)	(2,708,798)	-	(677,200)	(3,385,998)	-
Utah	404IP	UT	1.266%	(404)	7,443,237	7,854	(404)	7,442,833	7,853	(404)	7,442,429	7,853
Washington	404IP	WA	0.000%	(252)	2,020,489	-	(252)	2,020,237	-	(252)	2,019,985	-
Eastern Wyoming	404IP	WYP	1.117%	(6,676)	5,248,373	4,888	(6,676)	5,241,696	4,882	(6,676)	5,235,020	4,876
Western Wyoming	404IP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total Intangible Plant				(1,172,612)	337,287,926	730,789	(1,172,612)	336,115,314	730,009	(1,172,612)	334,942,702	729,229
Hydro Production Plant:												
Pre-merger Pacific	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Pre-merger Utah	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger Pacific	404HP	SG-P	2.131%	-	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228
Post-merger Utah	404HP	SG-U	0.000%	-	-	-	-	-	-	-	-	-
Total Hydro Plant				-	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228

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Solar Production Plant:												
Oregon	404XP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404XP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404XP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Solar Plant				-	-	-	-	-	-	-	-	-
Wind Production Plant:												
Oregon	404WP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404WP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404WP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Wind Plant				-	-	-	-	-	-	-	-	-
Renewable Production Plant:												
Oregon	404RP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404RP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404RP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Renewable Plant				-	-	-	-	-	-	-	-	-
Other Production Plant:												
Oregon	404OP	OR	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-
General Plant:												
California	404GP	CA	0.000%	-	513,307	-	-	513,307	-	-	513,307	-
General Office	404GP	CN	0.000%	-	-	-	-	-	-	-	-	-
Idaho	404GP	ID	0.000%	-	333,771	-	-	333,771	-	-	333,771	-
Oregon	404GP	OR	1.325%	-	5,690,473	6,282	-	5,690,473	6,282	-	5,690,473	6,282
General Office	404GP	SO	1.556%	-	2,196,886	2,848	-	2,196,886	2,848	-	2,196,886	2,848
Utah	404GP	UT	0.000%	-	33,127	-	-	33,127	-	-	33,127	-
Washington	404GP	WA	3.944%	-	2,573,715	8,458	-	2,573,715	8,458	-	2,573,715	8,458
Eastern Wyoming	404GP	WYP	0.073%	-	4,767,976	289	-	4,767,976	289	-	4,767,976	289
Western Wyoming	404GP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total General Plant				-	16,109,254	17,877	-	16,109,254	17,877	-	16,109,254	17,877
Total Amortization Expense				(1,172,612)	368,165,278	774,894	(1,172,612)	366,992,666	774,114	(1,172,612)	365,820,054	773,334
Total Depreciation & Amortization Expense				201,343,429	38,756,675,577	104,616,502	205,210,379	38,961,885,956	105,016,983	185,894,385	39,147,780,342	105,433,556

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DEPRECIATION EXPENSE													
Steam Production Plant:													
Pre-merger Pacific	403SP	SG	5.141%	(181,436)	986,503,495	4,227,001	(181,436)	986,322,059	4,226,224	(181,436)	986,140,623	4,225,446	(181,436)
Pre-merger Utah	403SP	SG	5.053%	(325,979)	1,012,748,870	4,265,124	(325,979)	1,012,422,891	4,263,751	(325,979)	1,012,096,911	4,262,378	(325,979)
Post-merger	403SP	SG	6.360%	5,943,066	5,121,309,393	27,127,527	(1,970,088)	5,119,339,305	27,138,056	(1,769,504)	5,117,569,801	27,128,146	206,976
Oregon	403SP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Washington	403SP	WA	0.000%	-	-	-	-	-	-	-	-	-	-
California	403SP	CA	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403SP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Idaho	403SP	ID	0.000%	-	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403SP	WYP	0.000%	-	-	-	-	-	-	-	-	-	-
Western Wyoming	403SP	WYU	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	403SP	SG	0.000%	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Post-merger	403SP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Steam Plant				5,435,650	7,121,828,609	35,619,652	(2,477,504)	7,119,351,106	35,628,030	(2,276,919)	7,117,074,187	35,615,970	(300,439)
Hydro Production Plant:													
Pre-merger Pacific	403HP	SG	2.311%	(29,571)	173,581,890	334,275	(29,571)	173,552,320	334,218	(29,571)	173,522,749	334,161	(29,571)
Pre-merger Utah	403HP	SG	3.187%	(19,142)	39,452,202	104,798	(19,142)	39,433,060	104,747	(19,142)	39,413,919	104,696	(19,142)
Post-merger	403HP	SG	4.498%	-	13,047,000	48,910	-	13,047,000	48,910	-	13,047,000	48,910	-
Post-merger	403HP	SG-P	3.538%	3,334,890	753,407,259	2,216,426	11,541,404	764,948,663	2,238,356	11,125,481	776,074,144	2,271,772	(110,088)
Post-merger	403HP	SG-U	4.611%	4,054,262	179,959,329	683,700	(93,348)	179,865,982	691,310	(93,348)	179,772,634	690,951	(93,348)
Total Hydro Plant				7,340,440	1,159,447,681	3,388,108	11,399,344	1,170,847,025	3,417,541	10,983,422	1,181,830,447	3,450,490	(252,148)
Solar Production Plant:													
Oregon	403XP	OR	13.803%	-	849,123	9,767	-	849,123	9,767	-	849,123	9,767	-
Utah	403XP	UT	4.546%	(123)	560,278	2,123	(123)	560,154	2,122	(123)	560,031	2,122	(123)
Post-merger	403XP	SG	0.000%	-	56,322	-	-	56,322	-	-	56,322	-	-
System	403XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Solar Plant				(123)	1,465,723	11,890	(123)	1,465,600	11,890	(123)	1,465,477	11,889	(123)
Wind Production Plant:													
Oregon	403WP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403WP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	403WP	SG	3.991%	8,834,362	3,817,741,944	12,682,796	(107,511)	3,817,634,433	12,697,308	(107,511)	3,817,526,922	12,696,951	2,589,333
System	403WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Wind Plant				8,834,362	3,817,741,944	12,682,796	(107,511)	3,817,634,433	12,697,308	(107,511)	3,817,526,922	12,696,951	2,589,333
Renewable Production Plant:													
Oregon	403RP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403RP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	403RP	SG	1.896%	13,715	158,210,604	249,946	14,174	158,224,778	249,968	14,174	158,238,952	249,990	14,174
System	403RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Renewable Plant				13,715	158,210,604	249,946	14,174	158,224,778	249,968	14,174	158,238,952	249,990	14,174

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Other Production Plant:													
Pre-merger Pacific	403OP	DGU	0.000%	-	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	403OP	SG	4.832%	(29,730)	88,705,033	357,237	(29,730)	88,675,303	357,118	(29,730)	88,645,573	356,998	(29,730)
Post-merger	403OP	SG	3.509%	3,838,455	1,968,928,355	5,751,464	(2,319,153)	1,966,609,202	5,753,685	(2,341,809)	1,964,267,393	5,746,871	(2,341,809)
Oregon	403OP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403OP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
System	403OP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Other Plant				3,808,725	2,057,868,518	6,108,702	(2,348,883)	2,055,519,635	6,110,803	(2,371,539)	2,053,148,096	6,103,869	(2,371,539)
Transmission Plant:													
California	403TP	CA	1.770%	-	-	-	-	-	-	-	-	-	-
Oregon	403TP	OR	1.770%	1,623,183	1,229,716	617	12,432,442	13,662,158	10,983	2,541,485	16,203,644	22,027	2,550,386
Washington	403TP	WA	1.770%	-	-	-	-	-	-	-	-	-	-
Wyoing	403TP	WYP	1.770%	-	-	-	-	-	-	-	-	-	-
Wyoming	403TP	WYU	1.770%	-	-	-	-	-	-	-	-	-	-
Utah	403TP	UT	1.770%	-	-	-	-	-	-	-	-	-	-
Idaho	403TP	ID	1.770%	-	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	403TP	SG	1.697%	(169,652)	471,327,100	666,844	(169,652)	471,157,448	666,604	(169,652)	470,987,797	666,364	(169,652)
Pre-merger Utah	403TP	SG	1.668%	(295,257)	603,218,218	838,908	(295,257)	602,922,961	838,497	(295,257)	602,627,704	838,087	(295,257)
Post-merger	403TP	SG	1.770%	75,727,536	10,716,115,014	15,750,991	8,622,610	10,724,737,624	15,813,201	32,022,452	10,756,760,076	15,843,178	13,317,679
System	403TP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Transmission Plant				76,885,809	11,791,890,048	17,257,359	20,590,144	11,812,480,192	17,329,286	34,099,029	11,846,579,221	17,369,656	15,403,157
Distribution Plant:													
California	403364	CA	2.814%	17,914,275	661,188,139	1,529,535	3,209,714	664,397,853	1,554,304	4,649,665	669,047,518	1,563,520	14,982,042
Oregon	403364	OR	2.340%	10,578,927	3,221,424,227	6,270,506	3,447,273	3,224,871,500	6,284,180	197,373,835	3,422,245,334	6,479,951	7,800,000
Washington	403364	WA	2.626%	2,323,678	717,875,595	1,568,435	847,931	718,723,526	1,571,905	781,416	719,504,942	1,573,688	2,025,710
Eastern Wyoming	403364	WYP	2.723%	35,629,485	858,397,924	1,907,336	2,131,351	860,529,275	1,950,177	2,339,180	862,868,455	1,955,249	2,825,192
Utah	403364	UT	2.572%	97,454,383	4,869,560,519	10,332,540	12,038,719	4,881,599,238	10,449,879	43,189,530	4,924,788,768	10,509,065	16,070,789
Idaho	403364	ID	2.602%	7,500,663	519,069,890	1,117,484	1,361,793	520,431,683	1,127,094	1,572,738	522,004,421	1,130,275	1,973,634
Western Wyoming	403364	WYU	2.707%	(53,455)	166,168,707	374,935	(53,455)	166,115,252	374,814	(53,455)	166,061,797	374,694	(53,455)
Pre-merger Pacific	403363	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Pre-merger Utah	403363	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	403363	SNPD	2.880%	-	35,847,239	86,026	-	35,847,239	86,026	-	35,847,239	86,026	-
System	403363	CN	0.000%	-	10,802,634	-	-	10,802,634	-	-	10,802,634	-	-
System	403363	SO	0.000%	-	-	-	-	-	-	-	-	-	-
System	403362	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	403362	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Distribution Plant				171,347,955	11,060,334,874	23,186,798	22,983,327	11,083,318,201	23,398,379	249,852,908	11,333,171,110	23,672,466	45,623,911
Energy Storage Plant:													
California	403ES	CA	0.000%	-	-	-	-	-	-	-	-	-	-
Oregon	403ES	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Washington	403ES	WA	0.000%	-	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403ES	WYP	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403ES	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Idaho	403ES	ID	0.000%	-	-	-	-	-	-	-	-	-	-
Western Wyoming	403ES	WYU	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	CN	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	SNPD	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	SO	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant				-	-	-	-	-	-	-	-	-	-

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Description	Account	2020P Factor	June 2025 Rate	Adjustments	Adjusted EPIS Balance Dec 2025	Depreciation Expense Dec 2025	Adjustments	Adjusted EPIS Balance Jan 2026	Depreciation Expense Jan 2026	Adjustments	Adjusted EPIS Balance Feb 2026	Depreciation Expense Feb 2026	Adjustments
General Plant:													
California	403GP	CA	1.093%	102,820	16,380,701	14,873	(40,340)	16,340,361	14,901	(40,190)	16,300,171	14,865	(38,352)
Oregon	403GP	OR	1.416%	663,055	157,344,691	185,223	(575,801)	156,768,890	185,275	(572,809)	156,196,081	184,597	(541,617)
Washington	403GP	WA	1.384%	152,254	35,854,648	41,278	(81,397)	35,773,251	41,319	(81,097)	35,692,155	41,225	(77,421)
Eastern Wyoming	403GP	WYP	1.228%	149,842	67,880,379	69,413	187,337	68,067,716	69,585	159,351	68,227,068	69,763	165,337
Utah	403GP	UT	1.411%	606,887	216,569,939	254,321	172,658	216,742,597	254,779	118,216	216,860,813	254,950	141,324
Idaho	403GP	ID	1.184%	163,291	42,822,360	42,172	26,018	42,848,378	42,265	17,067	42,865,444	42,286	19,383
Western Wyoming	403GP	WYU	1.369%	(17,563)	13,597,142	15,517	(17,563)	13,579,579	15,497	(17,563)	13,562,016	15,477	(17,563)
Pre-merger Pacific	403GP	SG	1.134%	(8,667)	603,747	575	(8,667)	595,080	567	(8,667)	586,414	558	(8,667)
Pre-merger Utah	403GP	SG	1.265%	(27,378)	2,109,184	2,237	(27,378)	2,081,805	2,208	(27,378)	2,054,427	2,179	(27,378)
Post-merger	403GP	SG	2.586%	(752,692)	114,289,365	247,101	(752,692)	113,536,673	245,479	(752,692)	112,783,980	243,857	(752,692)
System	403GP	SO	6.377%	16,142,674	993,504,065	5,236,750	2,147,346	995,651,411	5,285,348	1,472,908	997,124,319	5,294,967	1,813,369
System	403GP	SG	3.174%	(331)	190,901	505	(331)	190,570	505	(331)	190,238	504	(331)
System	403GP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	403GP	SNPD	0.000%	-	-	-	-	-	-	-	-	-	-
Customer Service	403GP	CN	2.941%	(77,602)	238,217,474	583,916	(77,602)	238,139,872	583,726	(77,602)	238,062,269	583,536	(77,602)
Fuel Related	403GP	SE	3.761%	(13,073)	2,734,841	8,591	(13,073)	2,721,768	8,550	(13,073)	2,708,695	8,509	(13,073)
Total General Plant				17,083,515	1,902,099,436	6,702,471	938,515	1,903,037,950	6,750,003	176,140	1,903,214,090	6,757,274	584,717
Mining Plant:													
Coal Mine	403MP	SE	0.000%	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant				-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Depreciation Expense				290,750,051	39,072,710,338	105,207,722	50,991,483	39,123,701,821	105,593,208	290,369,580	39,414,071,401	105,928,555	61,291,043
Amortization Expense													
Intangible Plant:													
California	404IP	CA	0.000%	(147)	471,458	-	(147)	471,311	-	(147)	471,164	-	(147)
Customer Service	404IP	CN	0.000%	(154,776)	(928,659)	-	(154,776)	(1,083,435)	-	(154,776)	(1,238,212)	-	(154,776)
Pre-merger Pacific	404IP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Idaho	404IP	ID	0.000%	(243)	4,355,135	-	(243)	4,354,893	-	(243)	4,354,650	-	(243)
Oregon	404IP	OR	0.192%	(225)	4,600,366	737	(225)	4,600,140	737	(225)	4,599,915	737	(225)
Fuel Related	404IP	SE	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404IP	SG	2.805%	(315,712)	200,789,859	469,667	(315,712)	200,474,147	468,929	(315,712)	200,158,436	468,191	(315,712)
Hydro Relicensing	404IP	SG-P	2.593%	-	103,455,075	223,581	-	103,455,075	223,581	-	103,455,075	223,581	-
Hydro Relicensing	404IP	SG-U	2.502%	(14,920)	9,934,694	20,727	(14,920)	9,919,774	20,696	(14,920)	9,904,853	20,665	(14,920)
Pre-merger Utah	404IP	SG	2.611%	(2,057)	465,257	1,015	(2,057)	463,200	1,010	(2,057)	461,143	1,006	(2,057)
General Office	404IP	SO	0.000%	(677,200)	(4,063,197)	-	(677,200)	(4,740,397)	-	(677,200)	(5,417,596)	-	(677,200)
Utah	404IP	UT	1.266%	(404)	7,442,025	7,853	(404)	7,441,622	7,852	(404)	7,441,218	7,852	(404)
Washington	404IP	WA	0.000%	(252)	2,019,733	-	(252)	2,019,481	-	(252)	2,019,229	-	(252)
Eastern Wyoming	404IP	WYP	1.117%	(6,676)	5,228,344	4,870	(6,676)	5,221,667	4,864	(6,676)	5,214,991	4,857	(6,676)
Western Wyoming	404IP	WYU	0.000%	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant				(1,172,612)	333,770,090	728,449	(1,172,612)	332,597,479	727,669	(1,172,612)	331,424,867	726,889	(1,172,612)
Hydro Production Plant:													
Pre-merger Pacific	404HP	SG	0.000%	-		-	-	-	-	-	-	-	-
Pre-merger Utah	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger Pacific	404HP	SG-P	2.131%	-	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-
Post-merger Utah	404HP	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant				-	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-

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Solar Production Plant:													
Oregon	404XP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	404XP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404XP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	404XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Solar Plant				-	-	-	-	-	-	-	-	-	-
Wind Production Plant:													
Oregon	404WP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	404WP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404WP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	404WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Wind Plant				-	-	-	-	-	-	-	-	-	-
Renewable Production Plant:													
Oregon	404RP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	404RP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404RP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	404RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Renewable Plant				-	-	-	-	-	-	-	-	-	-
Other Production Plant:													
Oregon	404OP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-	-
General Plant:													
California	404GP	CA	0.000%	-	513,307	-	-	513,307	-	-	513,307	-	-
General Office	404GP	CN	0.000%	-	-	-	-	-	-	-	-	-	-
Idaho	404GP	ID	0.000%	-	333,771	-	-	333,771	-	-	333,771	-	-
Oregon	404GP	OR	1.325%	-	5,690,473	6,282	-	5,690,473	6,282	-	5,690,473	6,282	-
General Office	404GP	SO	1.556%	-	2,196,886	2,848	-	2,196,886	2,848	-	2,196,886	2,848	-
Utah	404GP	UT	0.000%	-	33,127	-	-	33,127	-	-	33,127	-	-
Washington	404GP	WA	3.944%	-	2,573,715	8,458	-	2,573,715	8,458	-	2,573,715	8,458	-
Eastern Wyoming	404GP	WYP	0.073%	-	4,767,976	289	-	4,767,976	289	-	4,767,976	289	-
Western Wyoming	404GP	WYU	0.000%	-	-	-	-	-	-	-	-	-	-
Total General Plant				-	16,109,254	17,877	-	16,109,254	17,877	-	16,109,254	17,877	-
Total Amortization Expense				(1,172,612)	364,647,442	772,554	(1,172,612)	363,474,830	771,773	(1,172,612)	362,302,218	770,993	(1,172,612)
Total Depreciation & Amortization Expense				289,577,439	39,437,357,780	105,980,276	49,818,871	39,487,176,651	106,364,981	289,196,968	39,776,373,619	106,699,548	60,118,431

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DEPRECIATION EXPENSE												
Steam Production Plant:												
Pre-merger Pacific	403SP	SG	5.141%	985,959,187	4,224,669	(181,436)	985,777,751	4,223,891	(181,436)	985,596,315	4,223,114	(181,436)
Pre-merger Utah	403SP	SG	5.053%	1,011,770,932	4,261,006	(325,979)	1,011,444,952	4,259,633	(325,979)	1,011,118,973	4,258,261	(325,979)
Post-merger	403SP	SG	6.360%	5,117,776,778	27,124,005	14,734,973	5,132,511,750	27,163,602	22,294,719	5,154,806,469	27,261,732	21,426,202
Oregon	403SP	OR	0.000%	-	-	-	-	-	-	-	-	-
Washington	403SP	WA	0.000%	-	-	-	-	-	-	-	-	-
California	403SP	CA	0.000%	-	-	-	-	-	-	-	-	-
Utah	403SP	UT	0.000%	-	-	-	-	-	-	-	-	-
Idaho	403SP	ID	0.000%	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403SP	WYP	0.000%	-	-	-	-	-	-	-	-	-
Western Wyoming	403SP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403SP	SG	0.000%	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Post-merger	403SP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Steam Plant				7,116,773,747	35,609,680	14,227,557	7,131,001,305	35,647,126	21,787,303	7,152,788,608	35,743,106	20,918,786
Hydro Production Plant:												
Pre-merger Pacific	403HP	SG	2.311%	173,493,179	334,104	(29,571)	173,463,608	334,047	(29,571)	173,434,037	333,990	(29,571)
Pre-merger Utah	403HP	SG	3.187%	39,394,777	104,645	(19,142)	39,375,636	104,594	(19,142)	39,356,494	104,543	(19,142)
Post-merger	403HP	SG	4.498%	13,047,000	48,910	-	13,047,000	48,910	-	13,047,000	48,910	-
Post-merger	403HP	SG-P	3.538%	775,964,056	2,288,011	(40,458)	775,923,597	2,287,789	953,852	776,877,449	2,289,135	1,175,091
Post-merger	403HP	SG-U	4.611%	179,679,287	690,593	117,652	179,796,939	690,639	(93,348)	179,703,591	690,686	2,714,986
Total Hydro Plant				1,181,578,298	3,466,262	28,482	1,181,606,780	3,465,979	811,792	1,182,418,572	3,467,265	3,841,365
Solar Production Plant:												
Oregon	403XP	OR	13.803%	849,123	9,767	-	849,123	9,767	-	849,123	9,767	-
Utah	403XP	UT	4.546%	559,908	2,121	(123)	559,785	2,121	(123)	559,662	2,121	(123)
Post-merger	403XP	SG	0.000%	56,322	-	-	56,322	-	-	56,322	-	-
System	403XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Solar Plant				1,465,354	11,889	(123)	1,465,230	11,888	(123)	1,465,107	11,888	(123)
Wind Production Plant:												
Oregon	403WP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403WP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403WP	SG	3.991%	3,820,116,255	12,701,078	(107,511)	3,820,008,743	12,705,205	(107,511)	3,819,901,232	12,704,847	2,589,333
System	403WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Wind Plant				3,820,116,255	12,701,078	(107,511)	3,820,008,743	12,705,205	(107,511)	3,819,901,232	12,704,847	2,589,333
Renewable Production Plant:												
Oregon	403RP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403RP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403RP	SG	1.896%	158,253,126	250,013	641,478	158,894,604	250,531	14,174	158,908,778	251,048	14,174
System	403RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Renewable Plant				158,253,126	250,013	641,478	158,894,604	250,531	14,174	158,908,778	251,048	14,174

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Description	Account	2020P Factor	June 2025 Rate	Adjusted EPIS Balance Mar 2026	Depreciation Expense Mar 2026	Adjustments	Adjusted EPIS Balance Apr 2026	Depreciation Expense Apr 2026	Adjustments	Adjusted EPIS Balance May 2026	Depreciation Expense May 2026	Adjustments
Other Production Plant:												
Pre-merger Pacific	403OP	DGU	0.000%	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	403OP	SG	4.832%	88,615,843	356,878	(29,730)	88,586,113	356,759	(29,730)	88,556,383	356,639	9,447
Post-merger	403OP	SG	3.509%	1,961,925,584	5,740,024	28,830,123	1,990,755,708	5,778,749	(1,669,371)	1,989,086,337	5,818,458	(1,552,231)
Oregon	403OP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403OP	UT	0.000%	-	-	-	-	-	-	-	-	-
System	403OP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant				2,050,776,557	6,096,902	28,800,393	2,079,576,950	6,135,508	(1,699,101)	2,077,877,849	6,175,097	(1,542,784)
Transmission Plant:												
California	403TP	CA	1.770%	-	-	-	-	-	-	-	-	-
Oregon	403TP	OR	1.770%	18,754,030	25,782	43,684,671	62,438,701	59,882	113,634,884	176,073,585	175,909	582,547
Washington	403TP	WA	1.770%	-	-	-	-	-	-	-	-	-
Wyoing	403TP	WYP	1.770%	-	-	-	-	-	-	-	-	-
Wyoming	403TP	WYU	1.770%	-	-	-	-	-	-	-	-	-
Utah	403TP	UT	1.770%	-	-	-	-	-	-	-	-	-
Idaho	403TP	ID	1.770%	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	403TP	SG	1.697%	470,818,145	666,124	(169,652)	470,648,493	665,884	(169,652)	470,478,841	665,644	(169,652)
Pre-merger Utah	403TP	SG	1.668%	602,332,447	837,676	(295,257)	602,037,190	837,266	(295,257)	601,741,933	836,855	(295,257)
Post-merger	403TP	SG	1.770%	10,770,077,755	15,876,618	16,265,732	10,786,343,487	15,898,436	30,990,547	10,817,334,034	15,933,289	46,188,481
System	403TP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Transmission Plant				11,861,982,377	17,406,200	59,485,494	11,921,467,871	17,461,468	144,160,522	12,065,628,393	17,611,697	46,306,119
Distribution Plant:												
California	403364	CA	2.814%	684,029,560	1,586,539	3,306,457	687,336,017	1,607,983	23,139,514	710,475,532	1,638,992	27,408,418
Oregon	403364	OR	2.340%	3,430,045,335	6,679,965	8,698,485	3,438,743,820	6,696,048	9,592,554	3,448,336,374	6,713,879	26,722,156
Washington	403364	WA	2.626%	721,530,652	1,576,760	2,252,235	723,782,887	1,581,441	9,621,047	733,403,934	1,594,432	2,408,069
Eastern Wyoming	403364	WYP	2.723%	865,693,647	1,961,108	3,183,928	868,877,574	1,967,925	12,042,777	880,920,351	1,985,200	4,776,184
Utah	403364	UT	2.572%	4,940,859,557	10,572,571	15,110,901	4,955,970,458	10,605,987	81,776,561	5,037,747,019	10,709,817	21,209,774
Idaho	403364	ID	2.602%	523,978,055	1,134,121	2,003,112	525,981,167	1,138,432	3,871,986	529,853,153	1,144,803	2,362,021
Western Wyoming	403364	WYU	2.707%	166,008,342	374,573	(53,455)	165,954,887	374,453	(53,455)	165,901,432	374,332	(53,455)
Pre-merger Pacific	403363	SG	0.000%	-	-	-	-	-	-	-	-	-
Pre-merger Utah	403363	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403363	SNPD	2.880%	35,847,239	86,026	1,883,228	37,730,467	88,285	-	37,730,467	90,545	-
System	403363	CN	0.000%	10,802,634	-	-	10,802,634	-	-	10,802,634	-	-
System	403363	SO	0.000%	-	-	-	-	-	-	-	-	-
System	403362	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403362	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Distribution Plant				11,378,795,021	23,971,661	36,384,891	11,415,179,913	24,060,554	139,990,984	11,555,170,897	24,252,000	84,833,168
Energy Storage Plant:												
California	403ES	CA	0.000%	-	-	-	-	-	-	-	-	-
Oregon	403ES	OR	0.000%	-	-	-	-	-	-	-	-	-
Washington	403ES	WA	0.000%	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403ES	WYP	0.000%	-	-	-	-	-	-	-	-	-
Utah	403ES	UT	0.000%	-	-	-	-	-	-	-	-	-
Idaho	403ES	ID	0.000%	-	-	-	-	-	-	-	-	-
Western Wyoming	403ES	WYU	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	CN	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SNPD	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SO	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant				-	-	-	-	-	-	-	-	-

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General Plant:												
California	403GP	CA	1.093%	16,261,819	14,829	(36,694)	16,225,125	14,795	(29,574)	16,195,551	14,765	(34,732)
Oregon	403GP	OR	1.416%	155,654,464	183,940	(519,529)	155,134,935	183,314	(392,447)	154,742,487	182,776	(480,114)
Washington	403GP	WA	1.384%	35,614,734	41,134	3,830	35,618,564	41,091	(59,865)	35,558,699	41,059	(70,181)
Eastern Wyoming	403GP	WYP	1.228%	68,392,404	69,929	542,695	68,935,099	70,291	171,195	69,106,295	70,657	187,807
Utah	403GP	UT	1.411%	217,002,138	255,103	177,586	217,179,724	255,291	269,346	217,449,070	255,553	383,032
Idaho	403GP	ID	1.184%	42,884,827	42,304	18,133	42,902,960	42,323	21,507	42,924,467	42,342	27,247
Western Wyoming	403GP	WYU	1.369%	13,544,453	15,457	(17,563)	13,526,890	15,437	(17,563)	13,509,327	15,417	(17,563)
Pre-merger Pacific	403GP	SG	1.134%	577,747	550	(8,667)	569,080	542	(8,667)	560,413	534	(8,667)
Pre-merger Utah	403GP	SG	1.265%	2,027,049	2,150	(27,378)	1,999,670	2,122	(27,378)	1,972,292	2,093	(27,378)
Post-merger	403GP	SG	2.586%	112,031,288	242,235	(752,692)	111,278,596	240,613	(752,692)	110,525,903	238,991	(752,692)
System	403GP	SO	6.377%	998,937,688	5,303,699	2,026,900	1,000,964,588	5,313,903	2,826,819	1,003,791,407	5,326,799	5,943,341
System	403GP	SG	3.174%	189,907	503	(331)	189,576	502	(331)	189,244	501	(331)
System	403GP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403GP	SNPD	0.000%	-	-	-	-	-	-	-	-	-
Customer Service	403GP	CN	2.941%	237,984,667	583,346	(77,602)	237,907,065	583,156	(77,602)	237,829,462	582,966	(77,602)
Fuel Related	403GP	SE	3.761%	2,695,623	8,468	(13,073)	2,682,550	8,427	(13,073)	2,669,477	8,386	(13,073)
Total General Plant				1,903,798,807	6,763,647	1,315,614	1,905,114,421	6,771,805	1,909,675	1,907,024,095	6,782,838	5,059,093
Mining Plant:												
Coal Mine	403MP	SE	0.000%	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant				1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Depreciation Expense				39,475,362,444	106,277,331	140,776,275	39,616,138,718	106,510,065	306,867,715	39,923,006,433	106,999,787	162,019,132
Amortization Expense												
Intangible Plant:												
California	404IP	CA	0.000%	471,017	-	(147)	470,870	-	(147)	470,723	-	(147)
Customer Service	404IP	CN	0.000%	(1,392,988)	-	(154,776)	(1,547,765)	-	(154,776)	(1,702,541)	-	(154,776)
Pre-merger Pacific	404IP	SG	0.000%	-	-	-	-	-	-	-	-	-
Idaho	404IP	ID	0.000%	4,354,408	-	(243)	4,354,165	-	(243)	4,353,923	-	(243)
Oregon	404IP	OR	0.192%	4,599,690	737	(225)	4,599,464	737	(225)	4,599,239	737	(225)
Fuel Related	404IP	SE	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404IP	SG	2.805%	199,842,724	467,453	(315,712)	199,527,012	466,715	(315,712)	199,211,300	465,977	(315,712)
Hydro Relicensing	404IP	SG-P	2.593%	103,455,075	223,581	-	103,455,075	223,581	-	103,455,075	223,581	-
Hydro Relicensing	404IP	SG-U	2.502%	9,889,933	20,634	(14,920)	9,875,013	20,603	(14,920)	9,860,092	20,571	(14,920)
Pre-merger Utah	404IP	SG	2.611%	459,087	1,001	(2,057)	457,030	997	(2,057)	454,974	992	(2,057)
General Office	404IP	SO	0.000%	(6,094,796)	-	(677,200)	(6,771,996)	-	(677,200)	(7,449,195)	-	(677,200)
Utah	404IP	UT	1.266%	7,440,814	7,851	(404)	7,440,410	7,851	(404)	7,440,006	7,850	(404)
Washington	404IP	WA	0.000%	2,018,977	-	(252)	2,018,725	-	(252)	2,018,473	-	(252)
Eastern Wyoming	404IP	WYP	1.117%	5,208,315	4,851	(6,676)	5,201,638	4,845	(6,676)	5,194,962	4,839	(6,676)
Western Wyoming	404IP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total Intangible Plant				330,252,255	726,109	(1,172,612)	329,079,643	725,328	(1,172,612)	327,907,031	724,548	(1,172,612)
Hydro Production Plant:												
Pre-merger Pacific	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Pre-merger Utah	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger Pacific	404HP	SG-P	2.131%	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-
Post-merger Utah	404HP	SG-U	0.000%	-	-	-	-	-	-	-	-	-
Total Hydro Plant				14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-

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Solar Production Plant:												
Oregon	404XP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404XP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404XP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Solar Plant				-	-	-	-	-	-	-	-	-
Wind Production Plant:												
Oregon	404WP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404WP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404WP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Wind Plant				-	-	-	-	-	-	-	-	-
Renewable Production Plant:												
Oregon	404RP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404RP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404RP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Renewable Plant				-	-	-	-	-	-	-	-	-
Other Production Plant:												
Oregon	404OP	OR	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-
General Plant:												
California	404GP	CA	0.000%	513,307	-	-	513,307	-	-	513,307	-	-
General Office	404GP	CN	0.000%	-	-	-	-	-	-	-	-	-
Idaho	404GP	ID	0.000%	333,771	-	-	333,771	-	-	333,771	-	-
Oregon	404GP	OR	1.325%	5,690,473	6,282	-	5,690,473	6,282	-	5,690,473	6,282	-
General Office	404GP	SO	1.556%	2,196,886	2,848	-	2,196,886	2,848	-	2,196,886	2,848	-
Utah	404GP	UT	0.000%	33,127	-	-	33,127	-	-	33,127	-	-
Washington	404GP	WA	3.944%	2,573,715	8,458	-	2,573,715	8,458	-	2,573,715	8,458	-
Eastern Wyoming	404GP	WYP	0.073%	4,767,976	289	-	4,767,976	289	-	4,767,976	289	-
Western Wyoming	404GP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total General Plant				16,109,254	17,877	-	16,109,254	17,877	-	16,109,254	17,877	-
Total Amortization Expense				361,129,606	770,213	(1,172,612)	359,956,994	769,433	(1,172,612)	358,784,383	768,653	(1,172,612)
Total Depreciation & Amortization Expense				39,836,492,050	107,047,544	139,603,663	39,976,095,713	107,279,497	305,695,103	40,281,790,815	107,768,440	160,846,520

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DEPRECIATION EXPENSE												
Steam Production Plant:												
Pre-merger Pacific	403SP	SG	5.141%	985,414,878	4,222,337	(181,436)	985,233,442	4,221,559	(181,436)	985,052,006	4,220,782	(181,436)
Pre-merger Utah	403SP	SG	5.053%	1,010,792,993	4,256,888	(325,979)	1,010,467,014	4,255,515	(325,979)	1,010,141,035	4,254,143	(325,979)
Post-merger	403SP	SG	6.360%	5,176,232,671	27,377,594	3,556,986	5,179,789,657	27,443,800	(2,146,619)	5,177,643,038	27,447,537	(1,998,942)
Oregon	403SP	OR	0.000%	-	-	-	-	-	-	-	-	-
Washington	403SP	WA	0.000%	-	-	-	-	-	-	-	-	-
California	403SP	CA	0.000%	-	-	-	-	-	-	-	-	-
Utah	403SP	UT	0.000%	-	-	-	-	-	-	-	-	-
Idaho	403SP	ID	0.000%	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403SP	WYP	0.000%	-	-	-	-	-	-	-	-	-
Western Wyoming	403SP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403SP	SG	0.000%	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Post-merger	403SP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Steam Plant				7,173,707,394	35,856,818	3,049,571	7,176,756,964	35,920,875	(2,654,035)	7,174,102,929	35,922,462	(2,506,358)
Hydro Production Plant:												
Pre-merger Pacific	403HP	SG	2.311%	173,404,467	333,933	(29,571)	173,374,896	333,876	(29,571)	173,345,326	333,819	(29,571)
Pre-merger Utah	403HP	SG	3.187%	39,337,352	104,492	(19,142)	39,318,211	104,442	(19,142)	39,299,069	104,391	(19,142)
Post-merger	403HP	SG	4.498%	13,047,000	48,910	-	13,047,000	48,910	-	13,047,000	48,910	-
Post-merger	403HP	SG-P	3.538%	778,052,540	2,292,274	680,381	778,732,921	2,295,009	511,812	779,244,732	2,296,767	1,350,422
Post-merger	403HP	SG-U	4.611%	182,418,578	695,723	(93,348)	182,325,230	700,760	(93,348)	182,231,883	700,401	(93,348)
Total Hydro Plant				1,186,259,938	3,475,332	538,321	1,186,798,259	3,482,996	369,752	1,187,168,010	3,484,288	1,208,362
Solar Production Plant:												
Oregon	403XP	OR	13.803%	849,123	9,767	-	849,123	9,767	-	849,123	9,767	-
Utah	403XP	UT	4.546%	559,539	2,120	(123)	559,416	2,120	(123)	559,292	2,119	(123)
Post-merger	403XP	SG	0.000%	56,322	-	-	56,322	-	-	56,322	-	-
System	403XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Solar Plant				1,464,984	11,887	(123)	1,464,861	11,887	(123)	1,464,738	11,886	(123)
Wind Production Plant:												
Oregon	403WP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403WP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403WP	SG	3.991%	3,822,490,565	12,708,975	(107,511)	3,822,383,054	12,713,102	(107,511)	3,822,275,542	12,712,744	2,589,333
System	403WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Wind Plant				3,822,490,565	12,708,975	(107,511)	3,822,383,054	12,713,102	(107,511)	3,822,275,542	12,712,744	2,589,333
Renewable Production Plant:												
Oregon	403RP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403RP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403RP	SG	1.896%	158,922,953	251,071	14,174	158,937,127	251,093	14,174	158,951,301	251,116	14,174
System	403RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Renewable Plant				158,922,953	251,071	14,174	158,937,127	251,093	14,174	158,951,301	251,116	14,174

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Other Production Plant:												
Pre-merger Pacific	403OP	DGU	0.000%	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	403OP	SG	4.832%	88,565,830	356,598	(29,730)	88,536,100	356,557	(29,730)	88,506,370	356,437	(29,730)
Post-merger	403OP	SG	3.509%	1,987,534,106	5,813,748	(2,180,692)	1,985,353,414	5,808,290	(2,341,809)	1,983,011,605	5,801,679	(2,341,809)
Oregon	403OP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403OP	UT	0.000%	-	-	-	-	-	-	-	-	-
System	403OP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant				2,076,335,066	6,170,346	(2,210,422)	2,074,124,644	6,164,848	(2,371,539)	2,071,753,105	6,158,116	(2,371,539)
Transmission Plant:												
California	403TP	CA	1.770%	-	-	-	-	-	-	-	-	-
Oregon	403TP	OR	1.770%	176,656,132	260,148	2,702,355	179,358,487	262,570	6,677,883	186,036,370	269,488	2,596,848
Washington	403TP	WA	1.770%	-	-	-	-	-	-	-	-	-
Wyoing	403TP	WYP	1.770%	-	-	-	-	-	-	-	-	-
Wyoming	403TP	WYU	1.770%	-	-	-	-	-	-	-	-	-
Utah	403TP	UT	1.770%	-	-	-	-	-	-	-	-	-
Idaho	403TP	ID	1.770%	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	403TP	SG	1.697%	470,309,189	665,404	(169,652)	470,139,537	665,164	(169,652)	469,969,885	664,924	(169,652)
Pre-merger Utah	403TP	SG	1.668%	601,446,676	836,445	(295,257)	601,151,419	836,034	(295,257)	600,856,162	835,624	(295,257)
Post-merger	403TP	SG	1.770%	10,863,522,515	15,990,211	21,075,856	10,884,598,371	16,039,820	79,969,686	10,964,568,057	16,114,344	43,285,373
System	403TP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Transmission Plant				12,111,934,512	17,752,207	23,313,302	12,135,247,814	17,803,588	86,182,660	12,221,430,474	17,884,380	45,417,313
Distribution Plant:												
California	403364	CA	2.814%	737,883,950	1,698,261	20,300,214	758,184,164	1,754,201	2,060,723	760,244,887	1,780,421	1,780,102
Oregon	403364	OR	2.340%	3,475,058,530	6,749,281	10,737,395	3,485,795,924	6,785,798	8,541,828	3,494,337,752	6,804,593	16,119,735
Washington	403364	WA	2.626%	735,812,004	1,607,594	2,847,960	738,659,963	1,613,345	2,142,832	740,802,795	1,618,806	1,487,637
Eastern Wyoming	403364	WYP	2.723%	885,696,535	2,004,282	4,798,439	890,494,974	2,015,145	5,791,087	896,286,060	2,027,159	5,374,404
Utah	403364	UT	2.572%	5,058,956,793	10,820,183	35,414,679	5,094,371,472	10,880,865	23,567,470	5,117,938,942	10,944,074	23,124,376
Idaho	403364	ID	2.602%	532,215,175	1,151,562	2,103,430	534,318,605	1,156,404	2,573,624	536,892,229	1,161,475	2,894,018
Western Wyoming	403364	WYU	2.707%	165,847,977	374,211	(53,455)	165,794,523	374,091	(53,455)	165,741,068	373,970	(53,455)
Pre-merger Pacific	403363	SG	0.000%	-	-	-	-	-	-	-	-	-
Pre-merger Utah	403363	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403363	SNPD	2.880%	37,730,467	90,545	-	37,730,467	90,545	-	37,730,467	90,545	-
System	403363	CN	0.000%	10,802,634	-	-	10,802,634	-	-	10,802,634	-	-
System	403363	SO	0.000%	-	-	-	-	-	-	-	-	-
System	403362	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403362	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Distribution Plant				11,640,004,065	24,495,919	76,148,661	11,716,152,726	24,670,394	44,624,109	11,760,776,835	24,801,042	50,726,817
Energy Storage Plant:												
California	403ES	CA	0.000%	-	-	-	-	-	-	-	-	-
Oregon	403ES	OR	0.000%	-	-	-	-	-	-	-	-	-
Washington	403ES	WA	0.000%	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403ES	WYP	0.000%	-	-	-	-	-	-	-	-	-
Utah	403ES	UT	0.000%	-	-	-	-	-	-	-	-	-
Idaho	403ES	ID	0.000%	-	-	-	-	-	-	-	-	-
Western Wyoming	403ES	WYU	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	CN	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SNPD	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SO	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant				-	-	-	-	-	-	-	-	-

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Description	Account	2020P Factor	June 2025 Rate	Adjusted EPIS Balance Jun 2026	Depreciation Expense Jun 2026	Adjustments	Adjusted EPIS Balance Jul 2026	Depreciation Expense Jul 2026	Adjustments	Adjusted EPIS Balance Aug 2026	Depreciation Expense Aug 2026	Adjustments
General Plant:												
California	403GP	CA	1.093%	16,160,819	14,735	(16,482)	16,144,336	14,712	(27,686)	16,116,650	14,692	(27,742)
Oregon	403GP	OR	1.416%	154,262,373	182,261	(169,896)	154,092,477	181,878	(359,338)	153,733,139	181,566	(360,294)
Washington	403GP	WA	1.384%	35,488,518	40,984	(33,682)	35,454,836	40,924	(56,089)	35,398,747	40,872	(56,201)
Eastern Wyoming	403GP	WYP	1.228%	69,294,102	70,840	167,343	69,461,445	71,022	184,208	69,645,653	71,202	173,883
Utah	403GP	UT	1.411%	217,832,102	255,937	372,184	218,204,285	256,381	479,443	218,683,728	256,882	390,758
Idaho	403GP	ID	1.184%	42,951,714	42,366	20,402	42,972,116	42,390	26,086	42,998,202	42,413	22,796
Western Wyoming	403GP	WYU	1.369%	13,491,765	15,397	(17,563)	13,474,202	15,377	(17,563)	13,456,639	15,357	(17,563)
Pre-merger Pacific	403GP	SG	1.134%	551,746	526	(8,667)	543,080	517	(8,667)	534,413	509	(8,667)
Pre-merger Utah	403GP	SG	1.265%	1,944,913	2,064	(27,378)	1,917,535	2,035	(27,378)	1,890,156	2,006	(27,378)
Post-merger	403GP	SG	2.586%	109,773,211	237,369	(752,692)	109,020,518	235,747	(752,692)	108,267,826	234,125	(752,692)
System	403GP	SO	6.377%	1,009,734,748	5,350,102	3,644,790	1,013,379,539	5,375,579	1,939,858	1,015,319,397	5,390,418	2,314,952
System	403GP	SG	3.174%	188,913	500	(331)	188,582	499	(331)	188,251	498	(331)
System	403GP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403GP	SNPD	0.000%	-	-	-	-	-	-	-	-	-
Customer Service	403GP	CN	2.941%	237,751,860	582,775	(77,602)	237,674,258	582,585	(77,602)	237,596,655	582,395	(77,602)
Fuel Related	403GP	SE	3.761%	2,656,404	8,345	(13,073)	2,643,331	8,304	(13,073)	2,630,259	8,263	(13,073)
Total General Plant				1,912,083,188	6,804,202	3,087,351	1,915,170,539	6,827,950	1,289,176	1,916,459,715	6,841,198	1,560,844
Mining Plant:												
Coal Mine	403MP	SE	0.000%	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant				1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Depreciation Expense				40,085,025,565	107,526,758	103,833,323	40,188,858,888	107,846,733	127,346,662	40,316,205,550	108,067,231	96,638,824
Amortization Expense												
Intangible Plant:												
California	404IP	CA	0.000%	470,576	-	(147)	470,429	-	(147)	470,282	-	(147)
Customer Service	404IP	CN	0.000%	(1,857,318)	-	(154,776)	(2,012,094)	-	(154,776)	(2,166,871)	-	(154,776)
Pre-merger Pacific	404IP	SG	0.000%	-	-	-	-	-	-	-	-	-
Idaho	404IP	ID	0.000%	4,353,680	-	(243)	4,353,437	-	(243)	4,353,195	-	(243)
Oregon	404IP	OR	0.192%	4,599,014	737	(225)	4,598,788	737	(225)	4,598,563	737	(225)
Fuel Related	404IP	SE	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404IP	SG	2.805%	198,895,589	465,239	(315,712)	198,579,877	464,501	(315,712)	198,264,165	463,764	(315,712)
Hydro Relicensing	404IP	SG-P	2.593%	103,455,075	223,581	-	103,455,075	223,581	-	103,455,075	223,581	-
Hydro Relicensing	404IP	SG-U	2.502%	9,845,172	20,540	(14,920)	9,830,251	20,509	(14,920)	9,815,331	20,478	(14,920)
Pre-merger Utah	404IP	SG	2.611%	452,917	988	(2,057)	450,860	983	(2,057)	448,804	979	(2,057)
General Office	404IP	SO	0.000%	(8,126,395)	-	(677,200)	(8,803,594)	-	(677,200)	(9,480,794)	-	(677,200)
Utah	404IP	UT	1.266%	7,439,603	7,850	(404)	7,439,199	7,850	(404)	7,438,795	7,849	(404)
Washington	404IP	WA	0.000%	2,018,221	-	(252)	2,017,970	-	(252)	2,017,718	-	(252)
Eastern Wyoming	404IP	WYP	1.117%	5,188,286	4,833	(6,676)	5,181,609	4,826	(6,676)	5,174,933	4,820	(6,676)
Western Wyoming	404IP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total Intangible Plant				326,734,419	723,768	(1,172,612)	325,561,807	722,988	(1,172,612)	324,389,195	722,208	(1,172,612)
Hydro Production Plant:												
Pre-merger Pacific	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Pre-merger Utah	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger Pacific	404HP	SG-P	2.131%	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-
Post-merger Utah	404HP	SG-U	0.000%	-	-	-	-	-	-	-	-	-
Total Hydro Plant				14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-

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Solar Production Plant:												
Oregon	404XP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404XP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404XP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Solar Plant				-	-	-	-	-	-	-	-	-
Wind Production Plant:												
Oregon	404WP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404WP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404WP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Wind Plant				-	-	-	-	-	-	-	-	-
Renewable Production Plant:												
Oregon	404RP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404RP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404RP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Renewable Plant				-	-	-	-	-	-	-	-	-
Other Production Plant:												
Oregon	404OP	OR	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-
General Plant:												
California	404GP	CA	0.000%	513,307	-	-	513,307	-	-	513,307	-	-
General Office	404GP	CN	0.000%	-	-	-	-	-	-	-	-	-
Idaho	404GP	ID	0.000%	333,771	-	-	333,771	-	-	333,771	-	-
Oregon	404GP	OR	1.325%	5,690,473	6,282	-	5,690,473	6,282	-	5,690,473	6,282	-
General Office	404GP	SO	1.556%	2,196,886	2,848	-	2,196,886	2,848	-	2,196,886	2,848	-
Utah	404GP	UT	0.000%	33,127	-	-	33,127	-	-	33,127	-	-
Washington	404GP	WA	3.944%	2,573,715	8,458	-	2,573,715	8,458	-	2,573,715	8,458	-
Eastern Wyoming	404GP	WYP	0.073%	4,767,976	289	-	4,767,976	289	-	4,767,976	289	-
Western Wyoming	404GP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total General Plant				16,109,254	17,877	-	16,109,254	17,877	-	16,109,254	17,877	-
Total Amortization Expense				357,611,771	767,873	(1,172,612)	356,439,159	767,092	(1,172,612)	355,266,547	766,312	(1,172,612)
Total Depreciation & Amortization Expense				40,442,637,336	108,294,630	102,660,711	40,545,298,047	108,613,826	126,174,051	40,671,472,097	108,833,543	95,466,212

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Description	Account	2020P Factor	June 2025 Rate	Adjusted EPIS Balance Sep 2026	Depreciation Expense Sep 2026	Adjustments	Adjusted EPIS Balance Oct 2026	Depreciation Expense Oct 2026	Adjustments	Adjusted EPIS Balance Nov 2026	Depreciation Expense Nov 2026	Adjustments
DEPRECIATION EXPENSE												
Steam Production Plant:												
Pre-merger Pacific	403SP	SG	5.141%	984,870,570	4,220,005	(181,436)	984,689,134	4,219,227	(181,436)	984,507,698	4,218,450	(181,436)
Pre-merger Utah	403SP	SG	5.053%	1,009,815,055	4,252,770	(325,979)	1,009,489,076	4,251,397	(325,979)	1,009,163,096	4,250,025	(325,979)
Post-merger	403SP	SG	6.360%	5,175,644,095	27,436,551	3,612,515	5,179,256,610	27,440,827	1,938,313	5,181,194,923	27,455,537	36,821,545
Oregon	403SP	OR	0.000%	-	-	-	-	-	-	-	-	-
Washington	403SP	WA	0.000%	-	-	-	-	-	-	-	-	-
California	403SP	CA	0.000%	-	-	-	-	-	-	-	-	-
Utah	403SP	UT	0.000%	-	-	-	-	-	-	-	-	-
Idaho	403SP	ID	0.000%	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403SP	WYP	0.000%	-	-	-	-	-	-	-	-	-
Western Wyoming	403SP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403SP	SG	0.000%	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Post-merger	403SP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Steam Plant				7,171,596,572	35,909,326	3,105,099	7,174,701,671	35,911,452	1,430,897	7,176,132,568	35,924,012	36,314,130
Hydro Production Plant:												
Pre-merger Pacific	403HP	SG	2.311%	173,315,755	333,762	(29,571)	173,286,185	333,705	(29,571)	173,256,614	333,648	(29,571)
Pre-merger Utah	403HP	SG	3.187%	39,279,927	104,340	(19,142)	39,260,786	104,289	(19,142)	39,241,644	104,238	(19,142)
Post-merger	403HP	SG	4.498%	13,047,000	48,910	-	13,047,000	48,910	-	13,047,000	48,910	-
Post-merger	403HP	SG-P	3.538%	780,595,154	2,299,512	3,880,078	784,475,232	2,307,223	19,966,553	804,441,785	2,342,377	75,094,455
Post-merger	403HP	SG-U	4.611%	182,138,535	700,042	9,249,539	191,388,074	717,634	1,542,255	192,930,329	738,367	12,731,429
Total Hydro Plant				1,188,376,372	3,486,566	13,080,905	1,201,457,277	3,511,761	21,460,097	1,222,917,374	3,567,541	87,777,172
Solar Production Plant:												
Oregon	403XP	OR	13.803%	849,123	9,767	-	849,123	9,767	-	849,123	9,767	70,080
Utah	403XP	UT	4.546%	559,169	2,119	(123)	559,046	2,118	(123)	558,923	2,118	(123)
Post-merger	403XP	SG	0.000%	56,322	-	-	56,322	-	-	56,322	-	-
System	403XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Solar Plant				1,464,615	11,886	(123)	1,464,492	11,886	(123)	1,464,368	11,885	69,957
Wind Production Plant:												
Oregon	403WP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403WP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403WP	SG	3.991%	3,824,864,875	12,716,871	(107,511)	3,824,757,364	12,720,999	1,936,225	3,826,693,589	12,724,040	17,589,829
System	403WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Wind Plant				3,824,864,875	12,716,871	(107,511)	3,824,757,364	12,720,999	1,936,225	3,826,693,589	12,724,040	17,589,829
Renewable Production Plant:												
Oregon	403RP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403RP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403RP	SG	1.896%	158,965,475	251,138	14,174	158,979,649	251,160	14,174	158,993,823	251,183	14,174
System	403RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Renewable Plant				158,965,475	251,138	14,174	158,979,649	251,160	14,174	158,993,823	251,183	14,174

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Other Production Plant:												
Pre-merger Pacific	403OP	DGU	0.000%	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	403OP	SG	4.832%	88,476,641	356,318	(29,730)	88,446,911	356,198	(29,730)	88,417,181	356,078	(29,730)
Post-merger	403OP	SG	3.509%	1,980,669,796	5,794,831	(2,253,699)	1,978,416,097	5,788,113	4,839,764	1,983,255,861	5,791,893	53,010,314
Oregon	403OP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403OP	UT	0.000%	-	-	-	-	-	-	-	-	-
System	403OP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant				2,069,381,566	6,151,149	(2,283,429)	2,067,098,137	6,144,311	4,810,034	2,071,908,171	6,147,972	52,980,584
Transmission Plant:												
California	403TP	CA	1.770%	-	-	-	-	-	-	-	-	-
Oregon	403TP	OR	1.770%	188,633,218	276,329	2,603,851	191,237,070	280,164	2,624,764	193,861,834	284,021	2,616,860
Washington	403TP	WA	1.770%	-	-	-	-	-	-	-	-	-
Wyoing	403TP	WYP	1.770%	-	-	-	-	-	-	-	-	-
Wyoming	403TP	WYU	1.770%	-	-	-	-	-	-	-	-	-
Utah	403TP	UT	1.770%	-	-	-	-	-	-	-	-	-
Idaho	403TP	ID	1.770%	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	403TP	SG	1.697%	469,800,234	664,684	(169,652)	469,630,582	664,444	(169,652)	469,460,930	664,204	(169,652)
Pre-merger Utah	403TP	SG	1.668%	600,560,904	835,213	(295,257)	600,265,647	834,803	(295,257)	599,970,390	834,392	(295,257)
Post-merger	403TP	SG	1.770%	11,007,853,430	16,205,248	57,329,804	11,065,183,234	16,279,454	51,106,412	11,116,289,646	16,359,428	92,870,614
System	403TP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Transmission Plant				12,266,847,787	17,981,474	59,468,746	12,326,316,533	18,058,865	53,266,268	12,379,582,800	18,142,045	95,022,565
Distribution Plant:												
California	403364	CA	2.814%	762,024,989	1,784,924	8,449,318	770,474,307	1,796,918	7,028,823	777,503,130	1,815,067	31,722,270
Oregon	403364	OR	2.340%	3,510,457,487	6,828,634	13,871,828	3,524,329,315	6,857,871	19,033,985	3,543,363,300	6,889,949	8,317,536
Washington	403364	WA	2.626%	742,290,432	1,622,779	1,330,263	743,620,695	1,625,862	1,030,922	744,651,617	1,628,445	1,536,651
Eastern Wyoming	403364	WYP	2.723%	901,660,465	2,039,827	4,379,317	906,039,781	2,050,892	26,575,622	932,615,404	2,086,012	6,162,611
Utah	403364	UT	2.572%	5,141,063,319	10,994,111	34,996,317	5,176,059,636	11,056,397	18,128,982	5,194,188,618	11,113,329	70,021,084
Idaho	403364	ID	2.602%	539,786,247	1,167,403	2,128,777	541,915,024	1,172,849	2,070,300	543,985,324	1,177,402	7,045,464
Western Wyoming	403364	WYU	2.707%	165,687,613	373,850	(53,455)	165,634,158	373,729	(53,455)	165,580,703	373,608	(53,455)
Pre-merger Pacific	403363	SG	0.000%	-	-	-	-	-	-	-	-	-
Pre-merger Utah	403363	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403363	SNPD	2.880%	37,730,467	90,545	-	37,730,467	90,545	-	37,730,467	90,545	-
System	403363	CN	0.000%	10,802,634	-	-	10,802,634	-	-	10,802,634	-	-
System	403363	SO	0.000%	-	-	-	-	-	-	-	-	-
System	403362	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403362	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Distribution Plant				11,811,503,652	24,902,072	65,102,365	11,876,606,017	25,025,064	73,815,180	11,950,421,197	25,174,358	124,752,161
Energy Storage Plant:												
California	403ES	CA	0.000%	-	-	-	-	-	-	-	-	-
Oregon	403ES	OR	0.000%	-	-	-	-	-	-	-	-	-
Washington	403ES	WA	0.000%	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403ES	WYP	0.000%	-	-	-	-	-	-	-	-	-
Utah	403ES	UT	0.000%	-	-	-	-	-	-	-	-	-
Idaho	403ES	ID	0.000%	-	-	-	-	-	-	-	-	-
Western Wyoming	403ES	WYU	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	CN	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SNPD	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SO	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant				-	-	-	-	-	-	-	-	-

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General Plant:												
California	403GP	CA	1.093%	16,088,909	14,667	(12,956)	16,075,952	14,648	(14,901)	16,061,051	14,635	(5,644)
Oregon	403GP	OR	1.416%	153,372,845	181,141	(109,944)	153,262,901	180,864	(141,371)	153,121,530	180,716	13,635
Washington	403GP	WA	1.384%	35,342,546	40,807	(26,630)	35,315,915	40,760	(30,520)	35,285,396	40,727	(12,005)
Eastern Wyoming	403GP	WYP	1.228%	69,819,535	71,385	184,097	70,003,632	71,569	201,022	70,204,654	71,766	1,134,929
Utah	403GP	UT	1.411%	219,074,486	257,393	380,123	219,454,609	257,847	485,145	219,939,754	258,355	378,508
Idaho	403GP	ID	1.184%	43,020,998	42,437	26,146	43,047,144	42,461	31,856	43,079,000	42,490	38,792
Western Wyoming	403GP	WYU	1.369%	13,439,076	15,337	(17,563)	13,421,513	15,317	(17,563)	13,403,950	15,297	(17,563)
Pre-merger Pacific	403GP	SG	1.134%	525,746	501	(8,667)	517,079	493	(8,667)	508,413	485	(8,667)
Pre-merger Utah	403GP	SG	1.265%	1,862,778	1,977	(27,378)	1,835,400	1,948	(27,378)	1,808,021	1,920	(27,378)
Post-merger	403GP	SG	2.586%	107,515,134	232,503	(752,692)	106,762,441	230,881	(752,692)	106,009,749	229,259	(752,692)
System	403GP	SO	6.377%	1,017,634,349	5,401,723	2,465,880	1,020,100,229	5,414,426	3,533,982	1,023,634,211	5,430,368	39,805,566
System	403GP	SG	3.174%	187,919	498	(331)	187,588	497	(331)	187,257	496	(331)
System	403GP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403GP	SNPD	0.000%	-	-	-	-	-	-	-	-	-
Customer Service	403GP	CN	2.941%	237,519,053	582,205	(77,602)	237,441,451	582,015	(77,602)	237,363,848	581,824	(77,602)
Fuel Related	403GP	SE	3.761%	2,617,186	8,222	(13,073)	2,604,113	8,181	(13,073)	2,591,040	8,140	(13,073)
Total General Plant				1,918,020,559	6,850,797	2,009,408	1,920,029,967	6,861,905	3,167,905	1,923,197,872	6,876,477	40,456,474
Mining Plant:												
Coal Mine	403MP	SE	0.000%	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant				1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Depreciation Expense				40,412,844,374	108,261,279	140,389,634	40,553,234,008	108,497,402	159,900,657	40,713,134,665	108,819,513	454,977,045
Amortization Expense												
Intangible Plant:												
California	404IP	CA	0.000%	470,134	-	(147)	469,987	-	(147)	469,840	-	(147)
Customer Service	404IP	CN	0.000%	(2,321,647)	-	(154,776)	(2,476,423)	-	(154,776)	(2,631,200)	-	(154,776)
Pre-merger Pacific	404IP	SG	0.000%	-	-	-	-	-	-	-	-	-
Idaho	404IP	ID	0.000%	4,352,952	-	(243)	4,352,710	-	(243)	4,352,467	-	(243)
Oregon	404IP	OR	0.192%	4,598,337	737	(225)	4,598,112	737	(225)	4,597,887	737	(225)
Fuel Related	404IP	SE	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404IP	SG	2.805%	197,948,453	463,026	(315,712)	197,632,742	462,288	(315,712)	197,317,030	461,550	(315,712)
Hydro Relicensing	404IP	SG-P	2.593%	103,455,075	223,581	-	103,455,075	223,581	-	103,455,075	223,581	-
Hydro Relicensing	404IP	SG-U	2.502%	9,800,410	20,447	(14,920)	9,785,490	20,416	(14,920)	9,770,570	20,385	(14,920)
Pre-merger Utah	404IP	SG	2.611%	446,747	974	(2,057)	444,691	970	(2,057)	442,634	965	(2,057)
General Office	404IP	SO	0.000%	(10,157,993)	-	(677,200)	(10,835,193)	-	(677,200)	(11,512,392)	-	(677,200)
Utah	404IP	UT	1.266%	7,438,391	7,849	(404)	7,437,988	7,848	(404)	7,437,584	7,848	(404)
Washington	404IP	WA	0.000%	2,017,466	-	(252)	2,017,214	-	(252)	2,016,962	-	(252)
Eastern Wyoming	404IP	WYP	1.117%	5,168,257	4,814	(6,676)	5,161,581	4,808	(6,676)	5,154,904	4,801	(6,676)
Western Wyoming	404IP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total Intangible Plant				323,216,583	721,428	(1,172,612)	322,043,972	720,647	(1,172,612)	320,871,360	719,867	(1,172,612)
Hydro Production Plant:												
Pre-merger Pacific	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Pre-merger Utah	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger Pacific	404HP	SG-P	2.131%	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-
Post-merger Utah	404HP	SG-U	0.000%	-	-	-	-	-	-	-	-	-
Total Hydro Plant				14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-

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Solar Production Plant:												
Oregon	404XP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404XP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404XP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Solar Plant				-	-	-	-	-	-	-	-	-
Wind Production Plant:												
Oregon	404WP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404WP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404WP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Wind Plant				-	-	-	-	-	-	-	-	-
Renewable Production Plant:												
Oregon	404RP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404RP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404RP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Renewable Plant				-	-	-	-	-	-	-	-	-
Other Production Plant:												
Oregon	404OP	OR	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-
General Plant:												
California	404GP	CA	0.000%	513,307	-	-	513,307	-	-	513,307	-	-
General Office	404GP	CN	0.000%	-	-	-	-	-	-	-	-	-
Idaho	404GP	ID	0.000%	333,771	-	-	333,771	-	-	333,771	-	-
Oregon	404GP	OR	1.325%	5,690,473	6,282	-	5,690,473	6,282	-	5,690,473	6,282	-
General Office	404GP	SO	1.556%	2,196,886	2,848	-	2,196,886	2,848	-	2,196,886	2,848	-
Utah	404GP	UT	0.000%	33,127	-	-	33,127	-	-	33,127	-	-
Washington	404GP	WA	3.944%	2,573,715	8,458	-	2,573,715	8,458	-	2,573,715	8,458	-
Eastern Wyoming	404GP	WYP	0.073%	4,767,976	289	-	4,767,976	289	-	4,767,976	289	-
Western Wyoming	404GP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total General Plant				16,109,254	17,877	-	16,109,254	17,877	-	16,109,254	17,877	-
Total Amortization Expense				354,093,935	765,532	(1,172,612)	352,921,323	764,752	(1,172,612)	351,748,711	763,972	(1,172,612)
Total Depreciation & Amortization Expense				40,766,938,309	109,026,811	139,217,022	40,906,155,331	109,262,154	158,728,045	41,064,883,376	109,583,485	453,804,434

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DEPRECIATION EXPENSE												
Steam Production Plant:												
Pre-merger Pacific	403SP	SG	5.141%	984,326,261	4,217,673	(181,436)	984,144,825	4,216,895	(181,436)	983,963,389	4,216,118	(181,436)
Pre-merger Utah	403SP	SG	5.053%	1,008,837,117	4,248,652	(325,979)	1,008,511,137	4,247,280	(325,979)	1,008,185,158	4,245,907	(325,979)
Post-merger	403SP	SG	6.360%	5,218,016,468	27,558,252	(2,804,129)	5,215,212,340	27,648,400	(1,729,138)	5,213,483,202	27,636,386	(2,864,959)
Oregon	403SP	OR	0.000%	-	-	-	-	-	-	-	-	-
Washington	403SP	WA	0.000%	-	-	-	-	-	-	-	-	-
California	403SP	CA	0.000%	-	-	-	-	-	-	-	-	-
Utah	403SP	UT	0.000%	-	-	-	-	-	-	-	-	-
Idaho	403SP	ID	0.000%	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403SP	WYP	0.000%	-	-	-	-	-	-	-	-	-
Western Wyoming	403SP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403SP	SG	0.000%	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Post-merger	403SP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Steam Plant				7,212,446,698	36,024,577	(3,311,544)	7,209,135,153	36,112,574	(2,236,553)	7,206,898,600	36,098,411	(3,372,374)
Hydro Production Plant:												
Pre-merger Pacific	403HP	SG	2.311%	173,227,044	333,591	(29,571)	173,197,473	333,534	(29,571)	173,167,903	333,478	(29,571)
Pre-merger Utah	403HP	SG	3.187%	39,222,503	104,187	(19,142)	39,203,361	104,137	(19,142)	39,184,219	104,086	(19,142)
Post-merger	403HP	SG	4.498%	13,047,000	48,910	-	13,047,000	48,910	-	13,047,000	48,910	-
Post-merger	403HP	SG-P	3.538%	879,536,240	2,482,516	(181,852)	879,354,389	2,592,952	(181,852)	879,172,537	2,592,416	(181,852)
Post-merger	403HP	SG-U	4.611%	205,661,758	765,790	(93,193)	205,568,565	790,071	(93,193)	205,475,372	789,713	382,689
Total Hydro Plant				1,310,694,545	3,734,995	(323,756)	1,310,370,789	3,869,604	(323,756)	1,310,047,032	3,868,602	152,125
Solar Production Plant:												
Oregon	403XP	OR	13.803%	919,203	10,170	-	919,203	10,573	-	919,203	10,573	-
Utah	403XP	UT	4.546%	558,800	2,117	(123)	558,677	2,117	(123)	558,554	2,116	(123)
Post-merger	403XP	SG	0.000%	56,322	-	-	56,322	-	-	56,322	-	-
System	403XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Solar Plant				1,534,325	12,288	(123)	1,534,202	12,690	(123)	1,534,079	12,690	(123)
Wind Production Plant:												
Oregon	403WP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403WP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403WP	SG	3.991%	3,844,283,418	12,756,511	(107,511)	3,844,175,906	12,785,583	(107,511)	3,844,068,395	12,785,225	3,049,675
System	403WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Wind Plant				3,844,283,418	12,756,511	(107,511)	3,844,175,906	12,785,583	(107,511)	3,844,068,395	12,785,225	3,049,675
Renewable Production Plant:												
Oregon	403RP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403RP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403RP	SG	1.896%	159,007,998	251,205	14,564	159,022,562	251,228	14,564	159,037,126	251,251	565,349
System	403RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Renewable Plant				159,007,998	251,205	14,564	159,022,562	251,228	14,564	159,037,126	251,251	565,349

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Other Production Plant:												
Pre-merger Pacific	403OP	DGU	0.000%	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	403OP	SG	4.832%	88,387,451	355,959	(29,730)	88,357,721	355,839	(29,730)	88,327,991	355,719	(29,730)
Post-merger	403OP	SG	3.509%	2,036,266,176	5,876,469	(2,339,320)	2,033,926,855	5,950,549	(2,339,320)	2,031,587,535	5,943,709	(2,339,320)
Oregon	403OP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403OP	UT	0.000%	-	-	-	-	-	-	-	-	-
System	403OP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant				2,124,888,756	6,232,428	(2,369,050)	2,122,519,706	6,306,388	(2,369,050)	2,120,150,655	6,299,428	(2,369,050)
Transmission Plant:												
California	403TP	CA	1.770%	-	-	-	-	-	-	-	-	-
Oregon	403TP	OR	1.770%	196,478,694	287,887	101,657	196,580,350	289,892	118,417	196,698,768	290,054	118,417
Washington	403TP	WA	1.770%	-	-	-	-	-	-	-	-	-
Wyoing	403TP	WYP	1.770%	-	-	-	-	-	-	-	-	-
Wyoming	403TP	WYU	1.770%	-	-	-	-	-	-	-	-	-
Utah	403TP	UT	1.770%	-	-	-	-	-	-	-	-	-
Idaho	403TP	ID	1.770%	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	403TP	SG	1.697%	469,291,278	663,964	(169,652)	469,121,626	663,724	(169,652)	468,951,974	663,484	(169,652)
Pre-merger Utah	403TP	SG	1.668%	599,675,133	833,982	(295,257)	599,379,876	833,571	(295,257)	599,084,619	833,161	(295,257)
Post-merger	403TP	SG	1.770%	11,209,160,260	16,465,615	5,246,155	11,214,406,415	16,537,979	73,141,596	11,287,548,012	16,595,792	22,233,384
System	403TP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Transmission Plant				12,474,605,365	18,251,448	4,882,903	12,479,488,268	18,325,166	72,795,104	12,552,283,373	18,382,491	21,886,892
Distribution Plant:												
California	403364	CA	2.814%	809,225,399	1,860,504	3,162,548	812,387,948	1,901,408	4,584,987	816,972,934	1,910,493	14,783,828
Oregon	403364	OR	2.340%	3,551,680,837	6,916,613	3,095,346	3,554,776,183	6,927,739	2,681,603	3,557,457,786	6,933,371	7,563,816
Washington	403364	WA	2.626%	746,188,268	1,631,255	791,026	746,979,294	1,633,802	727,980	747,707,274	1,635,464	1,905,371
Eastern Wyoming	403364	WYP	2.723%	938,778,015	2,123,154	2,177,253	940,955,268	2,132,616	2,372,504	943,327,772	2,137,778	2,862,177
Utah	403364	UT	2.572%	5,264,209,702	11,207,795	11,589,218	5,275,798,920	11,295,253	12,860,253	5,288,659,173	11,321,454	14,209,002
Idaho	403364	ID	2.602%	551,030,788	1,187,286	1,579,006	552,609,795	1,196,637	1,817,235	554,427,030	1,200,320	2,359,642
Western Wyoming	403364	WYU	2.707%	165,527,248	373,488	(53,455)	165,473,793	373,367	(53,455)	165,420,338	373,247	(53,455)
Pre-merger Pacific	403363	SG	0.000%	-	-	-	-	-	-	-	-	-
Pre-merger Utah	403363	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403363	SNPD	2.880%	37,730,467	90,545	-	37,730,467	90,545	-	37,730,467	90,545	-
System	403363	CN	0.000%	10,802,634	-	-	10,802,634	-	-	10,802,634	-	-
System	403363	SO	0.000%	-	-	-	-	-	-	-	-	-
System	403362	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403362	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Distribution Plant				12,075,173,358	25,390,640	22,340,943	12,097,514,301	25,551,368	24,991,107	12,122,505,408	25,602,671	43,630,381
Energy Storage Plant:												
California	403ES	CA	0.000%	-	-	-	-	-	-	-	-	-
Oregon	403ES	OR	0.000%	-	-	-	-	-	-	-	-	-
Washington	403ES	WA	0.000%	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403ES	WYP	0.000%	-	-	-	-	-	-	-	-	-
Utah	403ES	UT	0.000%	-	-	-	-	-	-	-	-	-
Idaho	403ES	ID	0.000%	-	-	-	-	-	-	-	-	-
Western Wyoming	403ES	WYU	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	CN	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SNPD	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SO	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant				-	-	-	-	-	-	-	-	-

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Description	Account	2020P Factor	June 2025 Rate	Adjusted EPIS Balance Dec 2026	Depreciation Expense Dec 2026	Adjustments	Adjusted EPIS Balance Jan 2027	Depreciation Expense Jan 2027	Adjustments	Adjusted EPIS Balance Feb 2027	Depreciation Expense Feb 2027	Adjustments
General Plant:												
California	403GP	CA	1.093%	16,055,407	14,626	(41,255)	16,014,152	14,605	(41,108)	15,973,044	14,567	(39,315)
Oregon	403GP	OR	1.416%	153,135,165	180,640	(580,779)	152,554,386	180,306	(577,909)	151,976,477	179,622	(547,474)
Washington	403GP	WA	1.384%	35,273,391	40,702	(83,178)	35,190,213	40,647	(82,885)	35,107,327	40,551	(79,299)
Eastern Wyoming	403GP	WYP	1.228%	71,339,583	72,450	118,097	71,457,680	73,091	90,771	71,548,451	73,198	96,864
Utah	403GP	UT	1.411%	220,318,261	258,863	74,562	220,392,823	259,130	11,454	220,404,278	259,180	27,568
Idaho	403GP	ID	1.184%	43,117,792	42,525	26,270	43,144,062	42,557	17,094	43,161,156	42,578	19,513
Western Wyoming	403GP	WYU	1.369%	13,386,387	15,277	(17,563)	13,368,824	15,257	(17,563)	13,351,262	15,236	(17,563)
Pre-merger Pacific	403GP	SG	1.134%	499,746	476	(8,667)	491,079	468	(8,667)	482,412	460	(8,667)
Pre-merger Utah	403GP	SG	1.265%	1,780,643	1,891	(27,378)	1,753,264	1,862	(27,378)	1,725,886	1,833	(27,378)
Post-merger	403GP	SG	2.586%	105,257,056	227,637	(752,692)	104,504,364	226,015	(752,692)	103,751,672	224,392	(752,692)
System	403GP	SO	6.377%	1,063,439,777	5,545,525	603,434	1,064,043,211	5,652,895	1,029,954	1,065,073,164	5,657,235	3,313,876
System	403GP	SG	3.174%	186,926	495	(331)	186,594	494	(331)	186,263	493	(331)
System	403GP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403GP	SNPD	0.000%	-	-	-	-	-	-	-	-	-
Customer Service	403GP	CN	2.941%	237,286,246	581,634	(77,602)	237,208,643	581,444	(77,602)	237,131,041	581,254	(77,602)
Fuel Related	403GP	SE	3.761%	2,577,968	8,100	(13,073)	2,564,895	8,059	(13,073)	2,551,822	8,018	(13,073)
Total General Plant				1,963,654,347	6,990,840	(780,156)	1,962,874,191	7,096,828	(449,937)	1,962,424,254	7,098,619	1,894,426
Mining Plant:												
Coal Mine	403MP	SE	0.000%	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant				1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Depreciation Expense				41,168,111,710	109,644,932	20,346,268	41,188,457,978	110,311,429	92,313,844	41,280,771,823	110,399,388	65,437,301
Amortization Expense												
Intangible Plant:												
California	404IP	CA	0.000%	469,693	-	(147)	469,546	-	(147)	469,399	-	(147)
Customer Service	404IP	CN	0.000%	(2,785,976)	-	(154,776)	(2,940,753)	-	(154,776)	(3,095,529)	-	(154,776)
Pre-merger Pacific	404IP	SG	0.000%	-	-	-	-	-	-	-	-	-
Idaho	404IP	ID	0.000%	4,352,225	-	(243)	4,351,982	-	(243)	4,351,739	-	(243)
Oregon	404IP	OR	0.192%	4,597,661	737	(225)	4,597,436	737	(225)	4,597,210	737	(225)
Fuel Related	404IP	SE	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404IP	SG	2.805%	197,001,318	460,812	(315,712)	196,685,607	460,074	(315,712)	196,369,895	459,336	(315,712)
Hydro Relicensing	404IP	SG-P	2.593%	103,455,075	223,581	-	103,455,075	223,581	-	103,455,075	223,581	-
Hydro Relicensing	404IP	SG-U	2.502%	9,755,649	20,354	(14,920)	9,740,729	20,323	(14,920)	9,725,808	20,292	(14,920)
Pre-merger Utah	404IP	SG	2.611%	440,577	961	(2,057)	438,521	956	(2,057)	436,464	952	(2,057)
General Office	404IP	SO	0.000%	(12,189,592)	-	(677,200)	(12,866,792)	-	(677,200)	(13,543,991)	-	(677,200)
Utah	404IP	UT	1.266%	7,437,180	7,847	(404)	7,436,776	7,847	(404)	7,436,372	7,847	(404)
Washington	404IP	WA	0.000%	2,016,710	-	(252)	2,016,458	-	(252)	2,016,206	-	(252)
Eastern Wyoming	404IP	WYP	1.117%	5,148,228	4,795	(6,676)	5,141,552	4,789	(6,676)	5,134,875	4,783	(6,676)
Western Wyoming	404IP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total Intangible Plant				319,698,748	719,087	(1,172,612)	318,526,136	718,307	(1,172,612)	317,353,524	717,527	(1,172,612)
Hydro Production Plant:												
Pre-merger Pacific	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Pre-merger Utah	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger Pacific	404HP	SG-P	2.131%	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-
Post-merger Utah	404HP	SG-U	0.000%	-	-	-	-	-	-	-	-	-
Total Hydro Plant				14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-

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Solar Production Plant:												
Oregon	404XP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404XP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404XP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Solar Plant				-	-	-	-	-	-	-	-	-
Wind Production Plant:												
Oregon	404WP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404WP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404WP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Wind Plant				-	-	-	-	-	-	-	-	-
Renewable Production Plant:												
Oregon	404RP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404RP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404RP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Renewable Plant				-	-	-	-	-	-	-	-	-
Other Production Plant:												
Oregon	404OP	OR	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-
General Plant:												
California	404GP	CA	0.000%	513,307	-	-	513,307	-	-	513,307	-	-
General Office	404GP	CN	0.000%	-	-	-	-	-	-	-	-	-
Idaho	404GP	ID	0.000%	333,771	-	-	333,771	-	-	333,771	-	-
Oregon	404GP	OR	1.325%	5,690,473	6,282	-	5,690,473	6,282	-	5,690,473	6,282	-
General Office	404GP	SO	1.556%	2,196,886	2,848	-	2,196,886	2,848	-	2,196,886	2,848	-
Utah	404GP	UT	0.000%	33,127	-	-	33,127	-	-	33,127	-	-
Washington	404GP	WA	3.944%	2,573,715	8,458	-	2,573,715	8,458	-	2,573,715	8,458	-
Eastern Wyoming	404GP	WYP	0.073%	4,767,976	289	-	4,767,976	289	-	4,767,976	289	-
Western Wyoming	404GP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total General Plant				16,109,254	17,877	-	16,109,254	17,877	-	16,109,254	17,877	-
Total Amortization Expense				350,576,099	763,192	(1,172,612)	349,403,487	762,411	(1,172,612)	348,230,876	761,631	(1,172,612)
Total Depreciation & Amortization Expense				41,518,687,809	110,408,123	19,173,656	41,537,861,466	111,073,841	91,141,233	41,629,002,698	111,161,020	64,264,689

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DEPRECIATION EXPENSE													
Steam Production Plant:													
Pre-merger Pacific	403SP	SG	5.141%	983,781,953	4,215,341	-	983,781,953	4,214,952	-	983,781,953	4,214,952	-	983,781,953
Pre-merger Utah	403SP	SG	5.053%	1,007,859,178	4,244,534	-	1,007,859,178	4,243,848	-	1,007,859,178	4,243,848	-	1,007,859,178
Post-merger	403SP	SG	6.360%	5,210,618,243	27,624,212	-	5,210,618,243	27,616,619	-	5,210,618,243	27,616,619	-	5,210,618,243
Oregon	403SP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Washington	403SP	WA	0.000%	-	-	-	-	-	-	-	-	-	-
California	403SP	CA	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403SP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Idaho	403SP	ID	0.000%	-	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403SP	WYP	0.000%	-	-	-	-	-	-	-	-	-	-
Western Wyoming	403SP	WYU	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	403SP	SG	0.000%	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851
Post-merger	403SP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Steam Plant				7,203,526,226	36,084,087	-	7,203,526,226	36,075,419	-	7,203,526,226	36,075,419	-	7,203,526,226
Hydro Production Plant:													
Pre-merger Pacific	403HP	SG	2.311%	173,138,332	333,421	-	173,138,332	333,392	-	173,138,332	333,392	-	173,138,332
Pre-merger Utah	403HP	SG	3.187%	39,165,078	104,035	-	39,165,078	104,010	-	39,165,078	104,010	-	39,165,078
Post-merger	403HP	SG	4.498%	13,047,000	48,910	-	13,047,000	48,910	-	13,047,000	48,910	-	13,047,000
Post-merger	403HP	SG-P	3.538%	878,990,686	2,591,880	-	878,990,686	2,591,611	-	878,990,686	2,591,611	-	878,990,686
Post-merger	403HP	SG-U	4.611%	205,858,061	790,270	-	205,858,061	791,005	-	205,858,061	791,005	-	205,858,061
Total Hydro Plant				1,310,199,157	3,868,515	-	1,310,199,157	3,868,928	-	1,310,199,157	3,868,928	-	1,310,199,157
Solar Production Plant:													
Oregon	403XP	OR	13.803%	919,203	10,573	-	919,203	10,573	-	919,203	10,573	-	919,203
Utah	403XP	UT	4.546%	558,430	2,116	-	558,430	2,116	-	558,430	2,116	-	558,430
Post-merger	403XP	SG	0.000%	56,322	-	-	56,322	-	-	56,322	-	-	56,322
System	403XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Solar Plant				1,533,956	12,689	-	1,533,956	12,689	-	1,533,956	12,689	-	1,533,956
Wind Production Plant:													
Oregon	403WP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403WP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	403WP	SG	3.991%	3,847,118,070	12,790,118	-	3,847,118,070	12,795,190	-	3,847,118,070	12,795,190	-	3,847,118,070
System	403WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Wind Plant				3,847,118,070	12,790,118	-	3,847,118,070	12,795,190	-	3,847,118,070	12,795,190	-	3,847,118,070
Renewable Production Plant:													
Oregon	403RP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403RP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	403RP	SG	1.896%	159,602,475	251,709	-	159,602,475	252,156	-	159,602,475	252,156	-	159,602,475
System	403RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Renewable Plant				159,602,475	251,709	-	159,602,475	252,156	-	159,602,475	252,156	-	159,602,475

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Description	Account	2020P Factor	June 2025 Rate	Adjusted EPIS Balance Mar 2027	Depreciation Expense Mar 2027	Adjustments	Adjusted EPIS Balance Apr 2027	Depreciation Expense Apr 2027	Adjustments	Adjusted EPIS Balance May 2027	Depreciation Expense May 2027	Adjustments	Adjusted EPIS Balance Jun 2027
Other Production Plant:													
Pre-merger Pacific	403OP	DGU	0.000%	235,129	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	403OP	SG	4.832%	88,298,261	355,599	-	88,298,261	355,540	-	88,298,261	355,540	-	88,298,261
Post-merger	403OP	SG	3.509%	2,029,248,215	5,936,869	-	2,029,248,215	5,933,449	-	2,029,248,215	5,933,449	-	2,029,248,215
Oregon	403OP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403OP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
System	403OP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Other Plant				2,117,781,605	6,292,469	-	2,117,781,605	6,288,989	-	2,117,781,605	6,288,989	-	2,117,781,605
Transmission Plant:													
California	403TP	CA	1.770%	-	-	-	-	-	-	-	-	-	-
Oregon	403TP	OR	1.770%	196,817,185	290,229	-	196,817,185	290,316	-	196,817,185	290,316	-	196,817,185
Washington	403TP	WA	1.770%	-	-	-	-	-	-	-	-	-	-
Wyoing	403TP	WYP	1.770%	-	-	-	-	-	-	-	-	-	-
Wyoming	403TP	WYU	1.770%	-	-	-	-	-	-	-	-	-	-
Utah	403TP	UT	1.770%	-	-	-	-	-	-	-	-	-	-
Idaho	403TP	ID	1.770%	-	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	403TP	SG	1.697%	468,782,323	663,244	-	468,782,323	663,124	-	468,782,323	663,124	-	468,782,323
Pre-merger Utah	403TP	SG	1.668%	598,789,362	832,750	-	598,789,362	832,545	-	598,789,362	832,545	-	598,789,362
Post-merger	403TP	SG	1.770%	11,309,781,396	16,666,134	-	11,309,781,396	16,682,531	-	11,309,781,396	16,682,531	-	11,309,781,396
System	403TP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Transmission Plant				12,574,170,265	18,452,357	-	12,574,170,265	18,468,516	-	12,574,170,265	18,468,516	-	12,574,170,265
Distribution Plant:													
California	403364	CA	2.814%	831,756,762	1,933,203	-	831,756,762	1,950,538	-	831,756,762	1,950,538	-	831,756,762
Oregon	403364	OR	2.340%	3,565,021,602	6,943,358	-	3,565,021,602	6,950,732	-	3,565,021,602	6,950,732	-	3,565,021,602
Washington	403364	WA	2.626%	749,612,645	1,638,345	-	749,612,645	1,640,430	-	749,612,645	1,640,430	-	749,612,645
Eastern Wyoming	403364	WYP	2.723%	946,189,949	2,143,717	-	946,189,949	2,146,964	-	946,189,949	2,146,964	-	946,189,949
Utah	403364	UT	2.572%	5,302,868,174	11,350,463	-	5,302,868,174	11,365,690	-	5,302,868,174	11,365,690	-	5,302,868,174
Idaho	403364	ID	2.602%	556,786,672	1,204,848	-	556,786,672	1,207,407	-	556,786,672	1,207,407	-	556,786,672
Western Wyoming	403364	WYU	2.707%	165,366,883	373,126	-	165,366,883	373,066	-	165,366,883	373,066	-	165,366,883
Pre-merger Pacific	403363	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Pre-merger Utah	403363	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	403363	SNPD	2.880%	37,730,467	90,545	-	37,730,467	90,545	-	37,730,467	90,545	-	37,730,467
System	403363	CN	0.000%	10,802,634	-	-	10,802,634	-	-	10,802,634	-	-	10,802,634
System	403363	SO	0.000%	-	-	-	-	-	-	-	-	-	-
System	403362	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	403362	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Distribution Plant				12,166,135,790	25,677,607	-	12,166,135,790	25,725,372	-	12,166,135,790	25,725,372	-	12,166,135,790
Energy Storage Plant:													
California	403ES	CA	0.000%	-	-	-	-	-	-	-	-	-	-
Oregon	403ES	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Washington	403ES	WA	0.000%	-	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403ES	WYP	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403ES	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Idaho	403ES	ID	0.000%	-	-	-	-	-	-	-	-	-	-
Western Wyoming	403ES	WYU	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	CN	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	SNPD	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	SO	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant				-	-	-	-	-	-	-	-	-	-

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Description	Account	2020P Factor	June 2025 Rate	Adjusted EPIS Balance Mar 2027	Depreciation Expense Mar 2027	Adjustments	Adjusted EPIS Balance Apr 2027	Depreciation Expense Apr 2027	Adjustments	Adjusted EPIS Balance May 2027	Depreciation Expense May 2027	Adjustments	Adjusted EPIS Balance Jun 2027
General Plant:													
California	403GP	CA	1.093%	15,933,729	14,530	-	15,933,729	14,513	-	15,933,729	14,513	-	15,933,729
Oregon	403GP	OR	1.416%	151,429,002	178,959	-	151,429,002	178,636	-	151,429,002	178,636	-	151,429,002
Washington	403GP	WA	1.384%	35,028,029	40,458	-	35,028,029	40,412	-	35,028,029	40,412	-	35,028,029
Eastern Wyoming	403GP	WYP	1.228%	71,645,315	73,294	-	71,645,315	73,343	-	71,645,315	73,343	-	71,645,315
Utah	403GP	UT	1.411%	220,431,846	259,203	-	220,431,846	259,219	-	220,431,846	259,219	-	220,431,846
Idaho	403GP	ID	1.184%	43,180,668	42,596	-	43,180,668	42,606	-	43,180,668	42,606	-	43,180,668
Western Wyoming	403GP	WYU	1.369%	13,333,699	15,216	-	13,333,699	15,206	-	13,333,699	15,206	-	13,333,699
Pre-merger Pacific	403GP	SG	1.134%	473,746	452	-	473,746	448	-	473,746	448	-	473,746
Pre-merger Utah	403GP	SG	1.265%	1,698,508	1,804	-	1,698,508	1,790	-	1,698,508	1,790	-	1,698,508
Post-merger	403GP	SG	2.586%	102,998,979	222,770	-	102,998,979	221,959	-	102,998,979	221,959	-	102,998,979
System	403GP	SO	6.377%	1,068,387,041	5,668,777	-	1,068,387,041	5,677,582	-	1,068,387,041	5,677,582	-	1,068,387,041
System	403GP	SG	3.174%	185,932	492	-	185,932	492	-	185,932	492	-	185,932
System	403GP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	403GP	SNPD	0.000%	-	-	-	-	-	-	-	-	-	-
Customer Service	403GP	CN	2.941%	237,053,439	581,064	-	237,053,439	580,969	-	237,053,439	580,969	-	237,053,439
Fuel Related	403GP	SE	3.761%	2,538,749	7,977	-	2,538,749	7,956	-	2,538,749	7,956	-	2,538,749
Total General Plant				1,964,318,680	7,107,593	-	1,964,318,680	7,115,131	-	1,964,318,680	7,115,131	-	1,964,318,680
Mining Plant:													
Coal Mine	403MP	SE	0.000%	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Mining Plant				1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Depreciation Expense				41,346,209,124	110,537,142	-	41,346,209,124	110,602,390	-	41,346,209,124	110,602,390	-	41,346,209,124
Amortization Expense													
Intangible Plant:													
California	404IP	CA	0.000%	469,252	-	-	469,252	-	-	469,252	-	-	469,252
Customer Service	404IP	CN	0.000%	(3,250,306)	-	-	(3,250,306)	-	-	(3,250,306)	-	-	(3,250,306)
Pre-merger Pacific	404IP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Idaho	404IP	ID	0.000%	4,351,497	-	-	4,351,497	-	-	4,351,497	-	-	4,351,497
Oregon	404IP	OR	0.192%	4,596,985	736	-	4,596,985	736	-	4,596,985	736	-	4,596,985
Fuel Related	404IP	SE	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404IP	SG	2.805%	196,054,183	458,598	-	196,054,183	458,229	-	196,054,183	458,229	-	196,054,183
Hydro Relicensing	404IP	SG-P	2.593%	103,455,075	223,581	-	103,455,075	223,581	-	103,455,075	223,581	-	103,455,075
Hydro Relicensing	404IP	SG-U	2.502%	9,710,888	20,260	-	9,710,888	20,245	-	9,710,888	20,245	-	9,710,888
Pre-merger Utah	404IP	SG	2.611%	434,408	947	-	434,408	945	-	434,408	945	-	434,408
General Office	404IP	SO	0.000%	(14,221,191)	-	-	(14,221,191)	-	-	(14,221,191)	-	-	(14,221,191)
Utah	404IP	UT	1.266%	7,435,969	7,846	-	7,435,969	7,846	-	7,435,969	7,846	-	7,435,969
Washington	404IP	WA	0.000%	2,015,954	-	-	2,015,954	-	-	2,015,954	-	-	2,015,954
Eastern Wyoming	404IP	WYP	1.117%	5,128,199	4,777	-	5,128,199	4,773	-	5,128,199	4,773	-	5,128,199
Western Wyoming	404IP	WYU	0.000%	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant				316,180,912	716,747	-	316,180,912	716,357	-	316,180,912	716,357	-	316,180,912
Hydro Production Plant:													
Pre-merger Pacific	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Pre-merger Utah	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger Pacific	404HP	SG-P	2.131%	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097
Post-merger Utah	404HP	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant				14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097

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Description	Account	2020P Factor	June 2025 Rate	Adjusted EPIS Balance Mar 2027	Depreciation Expense Mar 2027	Adjustments	Adjusted EPIS Balance Apr 2027	Depreciation Expense Apr 2027	Adjustments	Adjusted EPIS Balance May 2027	Depreciation Expense May 2027	Adjustments	Adjusted EPIS Balance Jun 2027
Solar Production Plant:													
Oregon	404XP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	404XP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404XP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	404XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Solar Plant				-	-	-	-	-	-	-	-	-	-
Wind Production Plant:													
Oregon	404WP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	404WP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404WP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	404WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Wind Plant				-	-	-	-	-	-	-	-	-	-
Renewable Production Plant:													
Oregon	404RP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	404RP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404RP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	404RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Renewable Plant				-	-	-	-	-	-	-	-	-	-
Other Production Plant:													
Oregon	404OP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-	-
General Plant:													
California	404GP	CA	0.000%	513,307	-	-	513,307	-	-	513,307	-	-	513,307
General Office	404GP	CN	0.000%	-	-	-	-	-	-	-	-	-	-
Idaho	404GP	ID	0.000%	333,771	-	-	333,771	-	-	333,771	-	-	333,771
Oregon	404GP	OR	1.325%	5,690,473	6,282	-	5,690,473	6,282	-	5,690,473	6,282	-	5,690,473
General Office	404GP	SO	1.556%	2,196,886	2,848	-	2,196,886	2,848	-	2,196,886	2,848	-	2,196,886
Utah	404GP	UT	0.000%	33,127	-	-	33,127	-	-	33,127	-	-	33,127
Washington	404GP	WA	3.944%	2,573,715	8,458	-	2,573,715	8,458	-	2,573,715	8,458	-	2,573,715
Eastern Wyoming	404GP	WYP	0.073%	4,767,976	289	-	4,767,976	289	-	4,767,976	289	-	4,767,976
Western Wyoming	404GP	WYU	0.000%	-	-	-	-	-	-	-	-	-	-
Total General Plant				16,109,254	17,877	-	16,109,254	17,877	-	16,109,254	17,877	-	16,109,254
Total Amortization Expense				347,058,264	760,851	-	347,058,264	760,461	-	347,058,264	760,461	-	347,058,264
Total Depreciation & Amortization Expense				41,693,267,388	111,297,993	-	41,693,267,388	111,362,851	-	41,693,267,388	111,362,851	-	41,693,267,388

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Description	Account	2020P Factor	June 2025 Rate	Depreciation Expense Jun 2027	Adjustments	Adjusted EPIS Balance Jul 2027	Depreciation Expense Jul 2027	Adjustments	Adjusted EPIS Balance Aug 2027	Depreciation Expense Aug 2027	Adjustments	Adjusted EPIS Balance Sep 2027	Depreciation Expense Sep 2027
DEPRECIATION EXPENSE													
Steam Production Plant:													
Pre-merger Pacific	403SP	SG	5.141%	4,214,952	-	983,781,953	4,214,952	-	983,781,953	4,214,952	-	983,781,953	4,214,952
Pre-merger Utah	403SP	SG	5.053%	4,243,848	-	1,007,859,178	4,243,848	-	1,007,859,178	4,243,848	-	1,007,859,178	4,243,848
Post-merger	403SP	SG	6.360%	27,616,619	-	5,210,618,243	27,616,619	-	5,210,618,243	27,616,619	-	5,210,618,243	27,616,619
Oregon	403SP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Washington	403SP	WA	0.000%	-	-	-	-	-	-	-	-	-	-
California	403SP	CA	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403SP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Idaho	403SP	ID	0.000%	-	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403SP	WYP	0.000%	-	-	-	-	-	-	-	-	-	-
Western Wyoming	403SP	WYU	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	403SP	SG	0.000%	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-
Post-merger	403SP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Steam Plant				36,075,419	-	7,203,526,226	36,075,419	-	7,203,526,226	36,075,419	-	7,203,526,226	36,075,419
Hydro Production Plant:													
Pre-merger Pacific	403HP	SG	2.311%	333,392	-	173,138,332	333,392	-	173,138,332	333,392	-	173,138,332	333,392
Pre-merger Utah	403HP	SG	3.187%	104,010	-	39,165,078	104,010	-	39,165,078	104,010	-	39,165,078	104,010
Post-merger	403HP	SG	4.498%	48,910	-	13,047,000	48,910	-	13,047,000	48,910	-	13,047,000	48,910
Post-merger	403HP	SG-P	3.538%	2,591,611	-	878,990,686	2,591,611	-	878,990,686	2,591,611	-	878,990,686	2,591,611
Post-merger	403HP	SG-U	4.611%	791,005	-	205,858,061	791,005	-	205,858,061	791,005	-	205,858,061	791,005
Total Hydro Plant				3,868,928	-	1,310,199,157	3,868,928	-	1,310,199,157	3,868,928	-	1,310,199,157	3,868,928
Solar Production Plant:													
Oregon	403XP	OR	13.803%	10,573	-	919,203	10,573	-	919,203	10,573	-	919,203	10,573
Utah	403XP	UT	4.546%	2,116	-	558,430	2,116	-	558,430	2,116	-	558,430	2,116
Post-merger	403XP	SG	0.000%	-	-	56,322	-	-	56,322	-	-	56,322	-
System	403XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Solar Plant				12,689	-	1,533,956	12,689	-	1,533,956	12,689	-	1,533,956	12,689
Wind Production Plant:													
Oregon	403WP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403WP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	403WP	SG	3.991%	12,795,190	-	3,847,118,070	12,795,190	-	3,847,118,070	12,795,190	-	3,847,118,070	12,795,190
System	403WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Wind Plant				12,795,190	-	3,847,118,070	12,795,190	-	3,847,118,070	12,795,190	-	3,847,118,070	12,795,190
Renewable Production Plant:													
Oregon	403RP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403RP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	403RP	SG	1.896%	252,156	-	159,602,475	252,156	-	159,602,475	252,156	-	159,602,475	252,156
System	403RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Renewable Plant				252,156	-	159,602,475	252,156	-	159,602,475	252,156	-	159,602,475	252,156

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Description	Account	2020P Factor	June 2025 Rate	Depreciation Expense Jun 2027	Adjustments	Adjusted EPIS Balance Jul 2027	Depreciation Expense Jul 2027	Adjustments	Adjusted EPIS Balance Aug 2027	Depreciation Expense Aug 2027	Adjustments	Adjusted EPIS Balance Sep 2027	Depreciation Expense Sep 2027
Other Production Plant:													
Pre-merger Pacific	403OP	DGU	0.000%	-	-	235,129	-	-	235,129	-	-	235,129	-
Post-merger	403OP	SG	4.832%	355,540	-	88,298,261	355,540	-	88,298,261	355,540	-	88,298,261	355,540
Post-merger	403OP	SG	3.509%	5,933,449	-	2,029,248,215	5,933,449	-	2,029,248,215	5,933,449	-	2,029,248,215	5,933,449
Oregon	403OP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403OP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
System	403OP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Other Plant				6,288,989	-	2,117,781,605	6,288,989	-	2,117,781,605	6,288,989	-	2,117,781,605	6,288,989
Transmission Plant:													
California	403TP	CA	1.770%	-	-	-	-	-	-	-	-	-	-
Oregon	403TP	OR	1.770%	290,316	-	196,817,185	290,316	-	196,817,185	290,316	-	196,817,185	290,316
Washington	403TP	WA	1.770%	-	-	-	-	-	-	-	-	-	-
Wyoing	403TP	WYP	1.770%	-	-	-	-	-	-	-	-	-	-
Wyoming	403TP	WYU	1.770%	-	-	-	-	-	-	-	-	-	-
Utah	403TP	UT	1.770%	-	-	-	-	-	-	-	-	-	-
Idaho	403TP	ID	1.770%	-	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	403TP	SG	1.697%	663,124	-	468,782,323	663,124	-	468,782,323	663,124	-	468,782,323	663,124
Pre-merger Utah	403TP	SG	1.668%	832,545	-	598,789,362	832,545	-	598,789,362	832,545	-	598,789,362	832,545
Post-merger	403TP	SG	1.770%	16,682,531	-	11,309,781,396	16,682,531	-	11,309,781,396	16,682,531	-	11,309,781,396	16,682,531
System	403TP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Transmission Plant				18,468,516	-	12,574,170,265	18,468,516	-	12,574,170,265	18,468,516	-	12,574,170,265	18,468,516
Distribution Plant:													
California	403364	CA	2.814%	1,950,538	-	831,756,762	1,950,538	-	831,756,762	1,950,538	-	831,756,762	1,950,538
Oregon	403364	OR	2.340%	6,950,732	-	3,565,021,602	6,950,732	-	3,565,021,602	6,950,732	-	3,565,021,602	6,950,732
Washington	403364	WA	2.626%	1,640,430	-	749,612,645	1,640,430	-	749,612,645	1,640,430	-	749,612,645	1,640,430
Eastern Wyoming	403364	WYP	2.723%	2,146,964	-	946,189,949	2,146,964	-	946,189,949	2,146,964	-	946,189,949	2,146,964
Utah	403364	UT	2.572%	11,365,690	-	5,302,868,174	11,365,690	-	5,302,868,174	11,365,690	-	5,302,868,174	11,365,690
Idaho	403364	ID	2.602%	1,207,407	-	556,786,672	1,207,407	-	556,786,672	1,207,407	-	556,786,672	1,207,407
Western Wyoming	403364	WYU	2.707%	373,066	-	165,366,883	373,066	-	165,366,883	373,066	-	165,366,883	373,066
Pre-merger Pacific	403363	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Pre-merger Utah	403363	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	403363	SNPD	2.880%	90,545	-	37,730,467	90,545	-	37,730,467	90,545	-	37,730,467	90,545
System	403363	CN	0.000%	-	-	10,802,634	-	-	10,802,634	-	-	10,802,634	-
System	403363	SO	0.000%	-	-	-	-	-	-	-	-	-	-
System	403362	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	403362	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Distribution Plant				25,725,372	-	12,166,135,790	25,725,372	-	12,166,135,790	25,725,372	-	12,166,135,790	25,725,372
Energy Storage Plant:													
California	403ES	CA	0.000%	-	-	-	-	-	-	-	-	-	-
Oregon	403ES	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Washington	403ES	WA	0.000%	-	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403ES	WYP	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	403ES	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Idaho	403ES	ID	0.000%	-	-	-	-	-	-	-	-	-	-
Western Wyoming	403ES	WYU	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	CN	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	SNPD	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	SO	0.000%	-	-	-	-	-	-	-	-	-	-
System	403ES	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant				-	-	-	-	-	-	-	-	-	-

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Description	Account	2020P Factor	June 2025 Rate	Depreciation Expense Jun 2027	Adjustments	Adjusted EPIS Balance Jul 2027	Depreciation Expense Jul 2027	Adjustments	Adjusted EPIS Balance Aug 2027	Depreciation Expense Aug 2027	Adjustments	Adjusted EPIS Balance Sep 2027	Depreciation Expense Sep 2027
General Plant:													
California	403GP	CA	1.093%	14,513	-	15,933,729	14,513	-	15,933,729	14,513	-	15,933,729	14,513
Oregon	403GP	OR	1.416%	178,636	-	151,429,002	178,636	-	151,429,002	178,636	-	151,429,002	178,636
Washington	403GP	WA	1.384%	40,412	-	35,028,029	40,412	-	35,028,029	40,412	-	35,028,029	40,412
Eastern Wyoming	403GP	WYP	1.228%	73,343	-	71,645,315	73,343	-	71,645,315	73,343	-	71,645,315	73,343
Utah	403GP	UT	1.411%	259,219	-	220,431,846	259,219	-	220,431,846	259,219	-	220,431,846	259,219
Idaho	403GP	ID	1.184%	42,606	-	43,180,668	42,606	-	43,180,668	42,606	-	43,180,668	42,606
Western Wyoming	403GP	WYU	1.369%	15,206	-	13,333,699	15,206	-	13,333,699	15,206	-	13,333,699	15,206
Pre-merger Pacific	403GP	SG	1.134%	448	-	473,746	448	-	473,746	448	-	473,746	448
Pre-merger Utah	403GP	SG	1.265%	1,790	-	1,698,508	1,790	-	1,698,508	1,790	-	1,698,508	1,790
Post-merger	403GP	SG	2.586%	221,959	-	102,998,979	221,959	-	102,998,979	221,959	-	102,998,979	221,959
System	403GP	SO	6.377%	5,677,582	-	1,068,387,041	5,677,582	-	1,068,387,041	5,677,582	-	1,068,387,041	5,677,582
System	403GP	SG	3.174%	492	-	185,932	492	-	185,932	492	-	185,932	492
System	403GP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	403GP	SNPD	0.000%	-	-	-	-	-	-	-	-	-	-
Customer Service	403GP	CN	2.941%	580,969	-	237,053,439	580,969	-	237,053,439	580,969	-	237,053,439	580,969
Fuel Related	403GP	SE	3.761%	7,956	-	2,538,749	7,956	-	2,538,749	7,956	-	2,538,749	7,956
Total General Plant				7,115,131	-	1,964,318,680	7,115,131	-	1,964,318,680	7,115,131	-	1,964,318,680	7,115,131
Mining Plant:													
Coal Mine	403MP	SE	0.000%	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Mining Plant				-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Depreciation Expense				110,602,390	-	41,346,209,124	110,602,390	-	41,346,209,124	110,602,390	-	41,346,209,124	110,602,390
Amortization Expense													
Intangible Plant:													
California	404IP	CA	0.000%	-	-	469,252	-	-	469,252	-	-	469,252	-
Customer Service	404IP	CN	0.000%	-	-	(3,250,306)	-	-	(3,250,306)	-	-	(3,250,306)	-
Pre-merger Pacific	404IP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Idaho	404IP	ID	0.000%	-	-	4,351,497	-	-	4,351,497	-	-	4,351,497	-
Oregon	404IP	OR	0.192%	736	-	4,596,985	736	-	4,596,985	736	-	4,596,985	736
Fuel Related	404IP	SE	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404IP	SG	2.805%	458,229	-	196,054,183	458,229	-	196,054,183	458,229	-	196,054,183	458,229
Hydro Relicensing	404IP	SG-P	2.593%	223,581	-	103,455,075	223,581	-	103,455,075	223,581	-	103,455,075	223,581
Hydro Relicensing	404IP	SG-U	2.502%	20,245	-	9,710,888	20,245	-	9,710,888	20,245	-	9,710,888	20,245
Pre-merger Utah	404IP	SG	2.611%	945	-	434,408	945	-	434,408	945	-	434,408	945
General Office	404IP	SO	0.000%	-	-	(14,221,191)	-	-	(14,221,191)	-	-	(14,221,191)	-
Utah	404IP	UT	1.266%	7,846	-	7,435,969	7,846	-	7,435,969	7,846	-	7,435,969	7,846
Washington	404IP	WA	0.000%	-	-	2,015,954	-	-	2,015,954	-	-	2,015,954	-
Eastern Wyoming	404IP	WYP	1.117%	4,773	-	5,128,199	4,773	-	5,128,199	4,773	-	5,128,199	4,773
Western Wyoming	404IP	WYU	0.000%	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant				716,357	-	316,180,912	716,357	-	316,180,912	716,357	-	316,180,912	716,357
Hydro Production Plant:													
Pre-merger Pacific	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Pre-merger Utah	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger Pacific	404HP	SG-P	2.131%	26,228	-	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228
Post-merger Utah	404HP	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant				26,228	-	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228

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Description	Account	2020P Factor	June 2025 Rate	Depreciation Expense Jun 2027	Adjustments	Adjusted EPIS Balance Jul 2027	Depreciation Expense Jul 2027	Adjustments	Adjusted EPIS Balance Aug 2027	Depreciation Expense Aug 2027	Adjustments	Adjusted EPIS Balance Sep 2027	Depreciation Expense Sep 2027
Solar Production Plant:													
Oregon	404XP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	404XP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404XP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	404XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Solar Plant				-	-	-	-	-	-	-	-	-	-
Wind Production Plant:													
Oregon	404WP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	404WP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404WP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	404WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Wind Plant				-	-	-	-	-	-	-	-	-	-
Renewable Production Plant:													
Oregon	404RP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Utah	404RP	UT	0.000%	-	-	-	-	-	-	-	-	-	-
Post-merger	404RP	SG	0.000%	-	-	-	-	-	-	-	-	-	-
System	404RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-	-
Total Renewable Plant				-	-	-	-	-	-	-	-	-	-
Other Production Plant:													
Oregon	404OP	OR	0.000%	-	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-	-
General Plant:													
California	404GP	CA	0.000%	-	-	513,307	-	-	513,307	-	-	513,307	-
General Office	404GP	CN	0.000%	-	-	-	-	-	-	-	-	-	-
Idaho	404GP	ID	0.000%	-	-	333,771	-	-	333,771	-	-	333,771	-
Oregon	404GP	OR	1.325%	6,282	-	5,690,473	6,282	-	5,690,473	6,282	-	5,690,473	6,282
General Office	404GP	SO	1.556%	2,848	-	2,196,886	2,848	-	2,196,886	2,848	-	2,196,886	2,848
Utah	404GP	UT	0.000%	-	-	33,127	-	-	33,127	-	-	33,127	-
Washington	404GP	WA	3.944%	8,458	-	2,573,715	8,458	-	2,573,715	8,458	-	2,573,715	8,458
Eastern Wyoming	404GP	WYP	0.073%	289	-	4,767,976	289	-	4,767,976	289	-	4,767,976	289
Western Wyoming	404GP	WYU	0.000%	-	-	-	-	-	-	-	-	-	-
Total General Plant				17,877	-	16,109,254	17,877	-	16,109,254	17,877	-	16,109,254	17,877
Total Amortization Expense				760,461	-	347,058,264	760,461	-	347,058,264	760,461	-	347,058,264	760,461
Total Depreciation & Amortization Expense				111,362,851	-	41,693,267,388	111,362,851	-	41,693,267,388	111,362,851	-	41,693,267,388	111,362,851

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Description	Account	2020P Factor	June 2025 Rate	Adjustments	Adjusted EPIS Balance Oct 2027	Depreciation Expense Oct 2027	Adjustments	Adjusted EPIS Balance Nov 2027	Depreciation Expense Nov 2027	Adjustments	Adjusted EPIS Balance Dec 2027	Depreciation Expense Dec 2027
DEPRECIATION EXPENSE												
Steam Production Plant:												
Pre-merger Pacific	403SP	SG	5.141%	-	983,781,953	4,214,952	-	983,781,953	4,214,952	-	983,781,953	4,214,952
Pre-merger Utah	403SP	SG	5.053%	-	1,007,859,178	4,243,848	-	1,007,859,178	4,243,848	-	1,007,859,178	4,243,848
Post-merger	403SP	SG	6.360%	-	5,210,618,243	27,616,619	-	5,210,618,243	27,616,619	-	5,210,618,243	27,616,619
Oregon	403SP	OR	0.000%	-	-	-	-	-	-	-	-	-
Washington	403SP	WA	0.000%	-	-	-	-	-	-	-	-	-
California	403SP	CA	0.000%	-	-	-	-	-	-	-	-	-
Utah	403SP	UT	0.000%	-	-	-	-	-	-	-	-	-
Idaho	403SP	ID	0.000%	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403SP	WYP	0.000%	-	-	-	-	-	-	-	-	-
Western Wyoming	403SP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403SP	SG	0.000%	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-
Post-merger	403SP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Steam Plant				-	7,203,526,226	36,075,419	-	7,203,526,226	36,075,419	-	7,203,526,226	36,075,419
Hydro Production Plant:												
Pre-merger Pacific	403HP	SG	2.311%	-	173,138,332	333,392	-	173,138,332	333,392	-	173,138,332	333,392
Pre-merger Utah	403HP	SG	3.187%	-	39,165,078	104,010	-	39,165,078	104,010	-	39,165,078	104,010
Post-merger	403HP	SG	4.498%	-	13,047,000	48,910	-	13,047,000	48,910	-	13,047,000	48,910
Post-merger	403HP	SG-P	3.538%	-	878,990,686	2,591,611	-	878,990,686	2,591,611	-	878,990,686	2,591,611
Post-merger	403HP	SG-U	4.611%	-	205,858,061	791,005	-	205,858,061	791,005	-	205,858,061	791,005
Total Hydro Plant				-	1,310,199,157	3,868,928	-	1,310,199,157	3,868,928	-	1,310,199,157	3,868,928
Solar Production Plant:												
Oregon	403XP	OR	13.803%	-	919,203	10,573	-	919,203	10,573	-	919,203	10,573
Utah	403XP	UT	4.546%	-	558,430	2,116	-	558,430	2,116	-	558,430	2,116
Post-merger	403XP	SG	0.000%	-	56,322	-	-	56,322	-	-	56,322	-
System	403XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Solar Plant				-	1,533,956	12,689	-	1,533,956	12,689	-	1,533,956	12,689
Wind Production Plant:												
Oregon	403WP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403WP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403WP	SG	3.991%	-	3,847,118,070	12,795,190	-	3,847,118,070	12,795,190	-	3,847,118,070	12,795,190
System	403WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Wind Plant				-	3,847,118,070	12,795,190	-	3,847,118,070	12,795,190	-	3,847,118,070	12,795,190
Renewable Production Plant:												
Oregon	403RP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403RP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	403RP	SG	1.896%	-	159,602,475	252,156	-	159,602,475	252,156	-	159,602,475	252,156
System	403RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Renewable Plant				-	159,602,475	252,156	-	159,602,475	252,156	-	159,602,475	252,156

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Description	Account	2020P Factor	June 2025 Rate	Adjustments	Adjusted EPIS Balance Oct 2027	Depreciation Expense Oct 2027	Adjustments	Adjusted EPIS Balance Nov 2027	Depreciation Expense Nov 2027	Adjustments	Adjusted EPIS Balance Dec 2027	Depreciation Expense Dec 2027
Other Production Plant:												
Pre-merger Pacific	403OP	DGU	0.000%	-	235,129	-	-	235,129	-	-	235,129	-
Post-merger	403OP	SG	4.832%	-	88,298,261	355,540	-	88,298,261	355,540	-	88,298,261	355,540
Post-merger	403OP	SG	3.509%	-	2,029,248,215	5,933,449	-	2,029,248,215	5,933,449	-	2,029,248,215	5,933,449
Oregon	403OP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	403OP	UT	0.000%	-	-	-	-	-	-	-	-	-
System	403OP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant				-	2,117,781,605	6,288,989	-	2,117,781,605	6,288,989	-	2,117,781,605	6,288,989
Transmission Plant:												
California	403TP	CA	1.770%	-	-	-	-	-	-	-	-	-
Oregon	403TP	OR	1.770%	-	196,817,185	290,316	-	196,817,185	290,316	-	196,817,185	290,316
Washington	403TP	WA	1.770%	-	-	-	-	-	-	-	-	-
Wyoing	403TP	WYP	1.770%	-	-	-	-	-	-	-	-	-
Wyoming	403TP	WYU	1.770%	-	-	-	-	-	-	-	-	-
Utah	403TP	UT	1.770%	-	-	-	-	-	-	-	-	-
Idaho	403TP	ID	1.770%	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	403TP	SG	1.697%	-	468,782,323	663,124	-	468,782,323	663,124	-	468,782,323	663,124
Pre-merger Utah	403TP	SG	1.668%	-	598,789,362	832,545	-	598,789,362	832,545	-	598,789,362	832,545
Post-merger	403TP	SG	1.770%	-	11,309,781,396	16,682,531	-	11,309,781,396	16,682,531	-	11,309,781,396	16,682,531
System	403TP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Transmission Plant				-	12,574,170,265	18,468,516	-	12,574,170,265	18,468,516	-	12,574,170,265	18,468,516
Distribution Plant:												
California	403364	CA	2.814%	-	831,756,762	1,950,538	-	831,756,762	1,950,538	-	831,756,762	1,950,538
Oregon	403364	OR	2.340%	-	3,565,021,602	6,950,732	-	3,565,021,602	6,950,732	-	3,565,021,602	6,950,732
Washington	403364	WA	2.626%	-	749,612,645	1,640,430	-	749,612,645	1,640,430	-	749,612,645	1,640,430
Eastern Wyoming	403364	WYP	2.723%	-	946,189,949	2,146,964	-	946,189,949	2,146,964	-	946,189,949	2,146,964
Utah	403364	UT	2.572%	-	5,302,868,174	11,365,690	-	5,302,868,174	11,365,690	-	5,302,868,174	11,365,690
Idaho	403364	ID	2.602%	-	556,786,672	1,207,407	-	556,786,672	1,207,407	-	556,786,672	1,207,407
Western Wyoming	403364	WYU	2.707%	-	165,366,883	373,066	-	165,366,883	373,066	-	165,366,883	373,066
Pre-merger Pacific	403363	SG	0.000%	-	-	-	-	-	-	-	-	-
Pre-merger Utah	403363	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403363	SNPD	2.880%	-	37,730,467	90,545	-	37,730,467	90,545	-	37,730,467	90,545
System	403363	CN	0.000%	-	10,802,634	-	-	10,802,634	-	-	10,802,634	-
System	403363	SO	0.000%	-	-	-	-	-	-	-	-	-
System	403362	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403362	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Distribution Plant				-	12,166,135,790	25,725,372	-	12,166,135,790	25,725,372	-	12,166,135,790	25,725,372
Energy Storage Plant:												
California	403ES	CA	0.000%	-	-	-	-	-	-	-	-	-
Oregon	403ES	OR	0.000%	-	-	-	-	-	-	-	-	-
Washington	403ES	WA	0.000%	-	-	-	-	-	-	-	-	-
Eastern Wyoming	403ES	WYP	0.000%	-	-	-	-	-	-	-	-	-
Utah	403ES	UT	0.000%	-	-	-	-	-	-	-	-	-
Idaho	403ES	ID	0.000%	-	-	-	-	-	-	-	-	-
Western Wyoming	403ES	WYU	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	CN	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SNPD	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	SO	0.000%	-	-	-	-	-	-	-	-	-
System	403ES	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant				-	-	-	-	-	-	-	-	-

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Description	Account	2020P Factor	June 2025 Rate	Adjustments	Adjusted EPIS Balance Oct 2027	Depreciation Expense Oct 2027	Adjustments	Adjusted EPIS Balance Nov 2027	Depreciation Expense Nov 2027	Adjustments	Adjusted EPIS Balance Dec 2027	Depreciation Expense Dec 2027
General Plant:												
California	403GP	CA	1.093%	-	15,933,729	14,513	-	15,933,729	14,513	-	15,933,729	14,513
Oregon	403GP	OR	1.416%	-	151,429,002	178,636	-	151,429,002	178,636	-	151,429,002	178,636
Washington	403GP	WA	1.384%	-	35,028,029	40,412	-	35,028,029	40,412	-	35,028,029	40,412
Eastern Wyoming	403GP	WYP	1.228%	-	71,645,315	73,343	-	71,645,315	73,343	-	71,645,315	73,343
Utah	403GP	UT	1.411%	-	220,431,846	259,219	-	220,431,846	259,219	-	220,431,846	259,219
Idaho	403GP	ID	1.184%	-	43,180,668	42,606	-	43,180,668	42,606	-	43,180,668	42,606
Western Wyoming	403GP	WYU	1.369%	-	13,333,699	15,206	-	13,333,699	15,206	-	13,333,699	15,206
Pre-merger Pacific	403GP	SG	1.134%	-	473,746	448	-	473,746	448	-	473,746	448
Pre-merger Utah	403GP	SG	1.265%	-	1,698,508	1,790	-	1,698,508	1,790	-	1,698,508	1,790
Post-merger	403GP	SG	2.586%	-	102,998,979	221,959	-	102,998,979	221,959	-	102,998,979	221,959
System	403GP	SO	6.377%	-	1,068,387,041	5,677,582	-	1,068,387,041	5,677,582	-	1,068,387,041	5,677,582
System	403GP	SG	3.174%	-	185,932	492	-	185,932	492	-	185,932	492
System	403GP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	403GP	SNPD	0.000%	-	-	-	-	-	-	-	-	-
Customer Service	403GP	CN	2.941%	-	237,053,439	580,969	-	237,053,439	580,969	-	237,053,439	580,969
Fuel Related	403GP	SE	3.761%	-	2,538,749	7,956	-	2,538,749	7,956	-	2,538,749	7,956
Total General Plant				-	1,964,318,680	7,115,131	-	1,964,318,680	7,115,131	-	1,964,318,680	7,115,131
Mining Plant:												
Coal Mine	403MP	SE	0.000%	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Mining Plant				-	1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Depreciation Expense				-	41,346,209,124	110,602,390	-	41,346,209,124	110,602,390	-	41,346,209,124	110,602,390
Amortization Expense												
Intangible Plant:												
California	404IP	CA	0.000%	-	469,252	-	-	469,252	-	-	469,252	-
Customer Service	404IP	CN	0.000%	-	(3,250,306)	-	-	(3,250,306)	-	-	(3,250,306)	-
Pre-merger Pacific	404IP	SG	0.000%	-	-	-	-	-	-	-	-	-
Idaho	404IP	ID	0.000%	-	4,351,497	-	-	4,351,497	-	-	4,351,497	-
Oregon	404IP	OR	0.192%	-	4,596,985	736	-	4,596,985	736	-	4,596,985	736
Fuel Related	404IP	SE	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404IP	SG	2.805%	-	196,054,183	458,229	-	196,054,183	458,229	-	196,054,183	458,229
Hydro Relicensing	404IP	SG-P	2.593%	-	103,455,075	223,581	-	103,455,075	223,581	-	103,455,075	223,581
Hydro Relicensing	404IP	SG-U	2.502%	-	9,710,888	20,245	-	9,710,888	20,245	-	9,710,888	20,245
Pre-merger Utah	404IP	SG	2.611%	-	434,408	945	-	434,408	945	-	434,408	945
General Office	404IP	SO	0.000%	-	(14,221,191)	-	-	(14,221,191)	-	-	(14,221,191)	-
Utah	404IP	UT	1.266%	-	7,435,969	7,846	-	7,435,969	7,846	-	7,435,969	7,846
Washington	404IP	WA	0.000%	-	2,015,954	-	-	2,015,954	-	-	2,015,954	-
Eastern Wyoming	404IP	WYP	1.117%	-	5,128,199	4,773	-	5,128,199	4,773	-	5,128,199	4,773
Western Wyoming	404IP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total Intangible Plant				-	316,180,912	716,357	-	316,180,912	716,357	-	316,180,912	716,357
Hydro Production Plant:												
Pre-merger Pacific	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Pre-merger Utah	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404HP	SG	0.000%	-	-	-	-	-	-	-	-	-
Post-merger Pacific	404HP	SG-P	2.131%	-	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228
Post-merger Utah	404HP	SG-U	0.000%	-	-	-	-	-	-	-	-	-
Total Hydro Plant				-	14,768,097	26,228	-	14,768,097	26,228	-	14,768,097	26,228

PacifiCorp
Oregon General Rate Case - December 2027
Jun 2025 - Dec 2027 Depreciation & Amortization Expense

Description	Account	2020P Factor	June 2025 Rate	Adjustments	Adjusted EPIS Balance Oct 2027	Depreciation Expense Oct 2027	Adjustments	Adjusted EPIS Balance Nov 2027	Depreciation Expense Nov 2027	Adjustments	Adjusted EPIS Balance Dec 2027	Depreciation Expense Dec 2027
Solar Production Plant:												
Oregon	404XP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404XP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404XP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404XP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Solar Plant				-	-	-	-	-	-	-	-	-
Wind Production Plant:												
Oregon	404WP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404WP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404WP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404WP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Wind Plant				-	-	-	-	-	-	-	-	-
Renewable Production Plant:												
Oregon	404RP	OR	0.000%	-	-	-	-	-	-	-	-	-
Utah	404RP	UT	0.000%	-	-	-	-	-	-	-	-	-
Post-merger	404RP	SG	0.000%	-	-	-	-	-	-	-	-	-
System	404RP	OTHER	0.000%	-	-	-	-	-	-	-	-	-
Total Renewable Plant				-	-	-	-	-	-	-	-	-
Other Production Plant:												
Oregon	404OP	OR	0.000%	-	-	-	-	-	-	-	-	-
Total Other Plant				-	-	-	-	-	-	-	-	-
General Plant:												
California	404GP	CA	0.000%	-	513,307	-	-	513,307	-	-	513,307	-
General Office	404GP	CN	0.000%	-	-	-	-	-	-	-	-	-
Idaho	404GP	ID	0.000%	-	333,771	-	-	333,771	-	-	333,771	-
Oregon	404GP	OR	1.325%	-	5,690,473	6,282	-	5,690,473	6,282	-	5,690,473	6,282
General Office	404GP	SO	1.556%	-	2,196,886	2,848	-	2,196,886	2,848	-	2,196,886	2,848
Utah	404GP	UT	0.000%	-	33,127	-	-	33,127	-	-	33,127	-
Washington	404GP	WA	3.944%	-	2,573,715	8,458	-	2,573,715	8,458	-	2,573,715	8,458
Eastern Wyoming	404GP	WYP	0.073%	-	4,767,976	289	-	4,767,976	289	-	4,767,976	289
Western Wyoming	404GP	WYU	0.000%	-	-	-	-	-	-	-	-	-
Total General Plant				-	16,109,254	17,877	-	16,109,254	17,877	-	16,109,254	17,877
Total Amortization Expense				-	347,058,264	760,461	-	347,058,264	760,461	-	347,058,264	760,461
Total Depreciation & Amortization Expense				-	41,693,267,388	111,362,851	-	41,693,267,388	111,362,851	-	41,693,267,388	111,362,851

PacifiCorp
Oregon General Rate Case - December 2027
Jun 2025 - Dec 2027 Depreciation & Amortization Expense

Description	Account	2020P Factor	June 2025 Rate	Test Period Depreciation Expense
DEPRECIATION EXPENSE				
Steam Production Plant:				
Pre-merger Pacific	403SP	SG	5.141%	50,582,921
Pre-merger Utah	403SP	SG	5.053%	50,932,353
Post-merger	403SP	SG	6.360%	331,458,573
Oregon	403SP	OR	0.000%	-
Washington	403SP	WA	0.000%	-
California	403SP	CA	0.000%	-
Utah	403SP	UT	0.000%	-
Idaho	403SP	ID	0.000%	-
Eastern Wyoming	403SP	WYP	0.000%	-
Western Wyoming	403SP	WYU	0.000%	-
Post-merger	403SP	SG	0.000%	-
Post-merger	403SP	OTHER	0.000%	-
Total Steam Plant				432,973,848
Hydro Production Plant:				
Pre-merger Pacific	403HP	SG	2.311%	4,000,962
Pre-merger Utah	403HP	SG	3.187%	1,248,344
Post-merger	403HP	SG	4.498%	586,919
Post-merger	403HP	SG-P	3.538%	31,101,750
Post-merger	403HP	SG-U	4.611%	9,489,097
Total Hydro Plant				46,427,073
Solar Production Plant:				
Oregon	403XP	OR	13.803%	126,881
Utah	403XP	UT	4.546%	25,390
Post-merger	403XP	SG	0.000%	-
System	403XP	OTHER	0.000%	-
Total Solar Plant				152,271
Wind Production Plant:				
Oregon	403WP	OR	0.000%	-
Utah	403WP	UT	0.000%	-
Post-merger	403WP	SG	3.991%	153,517,632
System	403WP	OTHER	0.000%	-
Total Wind Plant				153,517,632
Renewable Production Plant:				
Oregon	403RP	OR	0.000%	-
Utah	403RP	UT	0.000%	-
Post-merger	403RP	SG	1.896%	3,023,588
System	403RP	OTHER	0.000%	-
Total Renewable Plant				3,023,588

PacifiCorp
Oregon General Rate Case - December 2027
Jun 2025 - Dec 2027 Depreciation & Amortization Expense

Description	Account	2020P Factor	June 2025 Rate	Test Period Depreciation Expense
Other Production Plant:				
Pre-merger Pacific	403OP	DGU	0.000%	-
Post-merger	403OP	SG	4.832%	4,267,014
Post-merger	403OP	SG	3.509%	71,232,170
Oregon	403OP	OR	0.000%	-
Utah	403OP	UT	0.000%	-
System	403OP	OTHER	0.000%	-
Total Other Plant				75,499,184
Transmission Plant:				
California	403TP	CA	1.770%	-
Oregon	403TP	OR	1.770%	3,483,017
Washington	403TP	WA	1.770%	-
Wyoing	403TP	WYP	1.770%	-
Wyoming	403TP	WYU	1.770%	-
Utah	403TP	UT	1.770%	-
Idaho	403TP	ID	1.770%	-
Pre-merger Pacific	403TP	SG	1.697%	7,958,571
Pre-merger Utah	403TP	SG	1.668%	9,992,384
Post-merger	403TP	SG	1.770%	199,942,689
System	403TP	OTHER	0.000%	-
Total Transmission Plant				221,376,660
Distribution Plant:				
California	403364	CA	2.814%	23,299,947
Oregon	403364	OR	2.340%	83,361,056
Washington	403364	WA	2.626%	19,671,480
Eastern Wyoming	403364	WYP	2.723%	25,736,788
Utah	403364	UT	2.572%	136,258,385
Idaho	403364	ID	2.602%	14,468,467
Western Wyoming	403364	WYU	2.707%	4,477,332
Pre-merger Pacific	403363	SG	0.000%	-
Pre-merger Utah	403363	SG	0.000%	-
System	403363	SNPD	2.880%	1,086,539
System	403363	CN	0.000%	-
System	403363	SO	0.000%	-
System	403362	SG	0.000%	-
System	403362	OTHER	0.000%	-
Total Distribution Plant				308,359,995
Energy Storage Plant:				
California	403ES	CA	0.000%	-
Oregon	403ES	OR	0.000%	-
Washington	403ES	WA	0.000%	-
Eastern Wyoming	403ES	WYP	0.000%	-
Utah	403ES	UT	0.000%	-
Idaho	403ES	ID	0.000%	-
Western Wyoming	403ES	WYU	0.000%	-
System	403ES	CN	0.000%	-
System	403ES	SNPD	0.000%	-
System	403ES	SG	0.000%	-
System	403ES	SO	0.000%	-
System	403ES	OTHER	0.000%	-
Total Energy Storage Plant				-

PacifiCorp
Oregon General Rate Case - December 2027
Jun 2025 - Dec 2027 Depreciation & Amortization Expense

Description	Account	2020P Factor	June 2025 Rate	Test Period Depreciation Expense
General Plant:				
California	403GP	CA	1.093%	174,315
Oregon	403GP	OR	1.416%	2,146,608
Washington	403GP	WA	1.384%	485,367
Eastern Wyoming	403GP	WYP	1.228%	879,673
Utah	403GP	UT	1.411%	3,110,487
Idaho	403GP	ID	1.184%	511,184
Western Wyoming	403GP	WYU	1.369%	182,567
Pre-merger Pacific	403GP	SG	1.134%	5,410
Pre-merger Utah	403GP	SG	1.265%	21,608
Post-merger	403GP	SG	2.586%	2,670,813
System	403GP	SO	6.377%	68,077,147
System	403GP	SG	3.174%	5,906
System	403GP	SG	0.000%	-
System	403GP	SNPD	0.000%	-
Customer Service	403GP	CN	2.941%	6,972,479
Fuel Related	403GP	SE	3.761%	95,658
Total General Plant				85,339,221
Mining Plant:				
Coal Mine	403MP	SE	0.000%	-
Total Mining Plant				-
Total Depreciation Expense				1,326,669,471
Amortization Expense				
Intangible Plant:				
California	404IP	CA	0.000%	-
Customer Service	404IP	CN	0.000%	-
Pre-merger Pacific	404IP	SG	0.000%	-
Idaho	404IP	ID	0.000%	-
Oregon	404IP	OR	0.192%	8,838
Fuel Related	404IP	SE	0.000%	-
Post-merger	404IP	SG	2.805%	5,502,072
Hydro Relicensing	404IP	SG-P	2.593%	2,682,975
Hydro Relicensing	404IP	SG-U	2.502%	243,078
Pre-merger Utah	404IP	SG	2.611%	11,363
General Office	404IP	SO	0.000%	-
Utah	404IP	UT	1.266%	94,153
Washington	404IP	WA	0.000%	-
Eastern Wyoming	404IP	WYP	1.117%	57,310
Western Wyoming	404IP	WYU	0.000%	-
Total Intangible Plant				8,599,790
Hydro Production Plant:				
Pre-merger Pacific	404HP	SG	0.000%	-
Pre-merger Utah	404HP	SG	0.000%	-
Post-merger	404HP	SG	0.000%	-
Post-merger Pacific	404HP	SG-P	2.131%	314,732
Post-merger Utah	404HP	SG-U	0.000%	-
Total Hydro Plant				314,732

PacifiCorp
Oregon General Rate Case - December 2027
Jun 2025 - Dec 2027 Depreciation & Amortization Expense

Description	Account	2020P Factor	June 2025 Rate	Test Period Depreciation Expense
Solar Production Plant:				
Oregon	404XP	OR	0.000%	-
Utah	404XP	UT	0.000%	-
Post-merger	404XP	SG	0.000%	-
System	404XP	OTHER	0.000%	-
Total Solar Plant				-
Wind Production Plant:				
Oregon	404WP	OR	0.000%	-
Utah	404WP	UT	0.000%	-
Post-merger	404WP	SG	0.000%	-
System	404WP	OTHER	0.000%	-
Total Wind Plant				-
Renewable Production Plant:				
Oregon	404RP	OR	0.000%	-
Utah	404RP	UT	0.000%	-
Post-merger	404RP	SG	0.000%	-
System	404RP	OTHER	0.000%	-
Total Renewable Plant				-
Other Production Plant:				
Oregon	404OP	OR	0.000%	-
Total Other Plant				-
General Plant:				
California	404GP	CA	0.000%	-
General Office	404GP	CN	0.000%	-
Idaho	404GP	ID	0.000%	-
Oregon	404GP	OR	1.325%	75,382
General Office	404GP	SO	1.556%	34,180
Utah	404GP	UT	0.000%	-
Washington	404GP	WA	3.944%	101,497
Eastern Wyoming	404GP	WYP	0.073%	3,464
Western Wyoming	404GP	WYU	0.000%	-
Total General Plant				214,522
Total Amortization Expense				9,129,044
Total Depreciation & Amortization Expense				**1,335,798,515**

Ref. 6.1.4

PacifiCorp
Oregon General Rate Case - December 2027
Depreciation Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Depreciation Expense	108SP	3	(97,603,415)	SG	27.756%	(27,090,389)	
Steam Depreciation Expense	108SP	3	(95,459,160)	SG	27.756%	(26,495,239)	
Steam Depreciation Expense	108SP	3	(1,763,405,762)	SG	27.756%	(489,443,403)	
Hydro Depreciation Expense	108HP	3	(7,406,603)	SG	27.756%	(2,055,745)	
Hydro Depreciation Expense	108HP	3	(2,114,272)	SG	27.756%	(586,828)	
Hydro Depreciation Expense	108HP	3	(1,173,838)	SG	27.756%	(325,806)	
Hydro Depreciation Expense	108HP	3	(47,208,888)	SG-P	27.756%	(13,103,098)	
Hydro Depreciation Expense	108HP	3	(14,432,508)	SG-U	27.756%	(4,005,826)	
Solar Depreciation Expense	108XP	3	(239,203)	OR	100.000%	(239,203)	
Solar Depreciation Expense	108XP	3	(48,348)	UT	0.000%	-	
Wind Depreciation Expense	108WP	3	(307,515,396)	SG	27.756%	(85,352,665)	
Renewable Depreciation Expense	108RP	3	(6,017,689)	SG	27.756%	(1,670,244)	
Other Depreciation Expense	108OP	3	(89,779,400)	SG	27.756%	(24,918,788)	
Other Depreciation Expense	108OP	3	(7,946,861)	SG	27.756%	(2,205,697)	
Transmission Depreciation Expense	108TP	3	(3,955,388)	OR	100.000%	(3,955,388)	
Transmission Depreciation Expense	108TP	3	(12,483,380)	SG	27.756%	(3,464,834)	
Transmission Depreciation Expense	108TP	3	(14,007,246)	SG	27.756%	(3,887,792)	
Transmission Depreciation Expense	108TP	3	(344,661,086)	SG	27.756%	(95,662,665)	
Transmission Depreciation Expense	108TP	3	-	OTHER	0.000%	-	
Distribution Depreciation Expense	108360	3	(3,330,742)	Situs	100.000%	(937,382)	
Distribution Depreciation Expense	108361	3	(6,347,521)	Situs	100.000%	(1,786,405)	
Distribution Depreciation Expense	108362	3	(52,758,601)	Situs	100.000%	(14,848,035)	
Distribution Depreciation Expense	108363	3	(8,531,205)	Situs	100.000%	(2,400,966)	
Distribution Depreciation Expense	108364	3	(75,157,639)	Situs	100.000%	(21,151,875)	
Distribution Depreciation Expense	108365	3	(48,287,824)	Situs	100.000%	(13,589,809)	
Distribution Depreciation Expense	108366	3	(22,414,687)	Situs	100.000%	(6,308,243)	
Distribution Depreciation Expense	108367	3	(51,608,033)	Situs	100.000%	(14,524,227)	
Distribution Depreciation Expense	108368	3	(70,954,396)	Situs	100.000%	(19,968,941)	
Distribution Depreciation Expense	108369	3	(45,587,387)	Situs	100.000%	(12,829,816)	
Distribution Depreciation Expense	108370	3	(13,089,619)	Situs	100.000%	(3,683,857)	
Distribution Depreciation Expense	108371	3	(360,323)	Situs	100.000%	(101,407)	
Distribution Depreciation Expense	108372	3	-	Situs	100.000%	-	
Distribution Depreciation Expense	108373	3	(2,707,920)	Situs	100.000%	(762,099)	
Distribution Depreciation Expense	108363	3	(2,130,144)	SNPD	25.578%	(544,850)	
General Depreciation Expense	108GP	3	(526,781)	CA	0.000%	-	
General Depreciation Expense	108GP	3	(27,294)	OR	100.000%	(27,294)	
General Depreciation Expense	108GP	3	(1,162,984)	WA	0.000%	-	
General Depreciation Expense	108GP	3	(3,983,415)	WYP	0.000%	-	
General Depreciation Expense	108GP	3	(10,964,555)	UT	0.000%	-	
General Depreciation Expense	108GP	3	(2,245,193)	ID	0.000%	-	
General Depreciation Expense	108GP	3	(887,871)	WYU	0.000%	-	
General Depreciation Expense	108GP	3	165,454	DGP	57.843%	95,703	
General Depreciation Expense	108GP	3	513,009	DGU	0.000%	-	
General Depreciation Expense	108GP	3	2,192,082	SG	27.756%	608,425	
General Depreciation Expense	108GP	3	(103,494,230)	SO	27.909%	(28,884,092)	
General Depreciation Expense	108GP	3	(5,193)	SG	27.756%	(1,441)	
General Depreciation Expense	108GP	3	(12,391,247)	CN	30.140%	(3,734,691)	
General Depreciation Expense	108GP	3	37,381	SE	26.823%	10,027	
			(3,351,505,320)			(929,834,886)	**6.2.3**
Adjustment to Tax:							
ADIT Avg. Balance	282	3	218,851	SG	27.756%	60,743	**6.2.38**

Description of Adjustment:

This adjustment steps forward the depreciation reserve to a December 2027 13-month average level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the December 2027 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2025 to December 31, 2027.

This pro forma adjustment also includes the change in depreciation expense and reserve from UE-399 which aligned the depreciation lives with the 2021 IRP retirement dates for the following coal fired plants: Colstrip, Craig 2, and Hayden 1 & 2. This adjustment also includes a change in depreciation expense and reserve to align the depreciation lives with Order No. 24-447 in UE-433 for the following coal fired plants: Dave Johnston Units 1-4, Naughton 1 & 2, and Jim Bridger Units 1-4.

PacifiCorp
Oregon General Rate Case - December 2027
Amortization Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Intangible Amortization Reserve	111IP	3	3,021	CA	0.000%	-	
Intangible Amortization Reserve	111IP	3	3,178,870	CN	30.140%	958,104	
Intangible Amortization Reserve	111IP	3	4,982	ID	0.000%	-	
Intangible Amortization Reserve	111IP	3	(13,054)	OR	100.000%	(13,054)	
Intangible Amortization Reserve	111IP	3	(4,675,580)	SG	27.756%	(1,297,734)	
Intangible Amortization Reserve	111IP	3	(5,365,950)	SG-P	27.756%	(1,489,350)	
Intangible Amortization Reserve	111IP	3	(186,276)	SG-U	27.756%	(51,702)	
Intangible Amortization Reserve	111IP	3	18,570	DGU	0.000%	-	
Intangible Amortization Reserve	111IP	3	13,908,637	SO	27.909%	3,881,746	
Intangible Amortization Reserve	111IP	3	(180,104)	UT	0.000%	-	
Intangible Amortization Reserve	111IP	3	5,175	WA	0.000%	-	
Intangible Amortization Reserve	111IP	3	21,190	WYP	0.000%	-	
Hydro Amortization Reserve	111HP	5	(629,465)	SG-P	27.756%	(174,712)	
General Amortization Reserve	111GP	3	(150,764)	OR	100.000%	(150,764)	
General Amortization Reserve	111GP	3	(68,359)	SO	27.909%	(19,078)	
General Amortization Reserve	111GP	3	-	UT	0.000%	-	
General Amortization Reserve	111GP	3	(202,993)	WA	0.000%	-	
General Amortization Reserve	111GP	3	(6,927)	WYP	0.000%	-	
General Amortization Reserve	111GP	3	-	WYU	0.000%	-	
			5,660,973			1,643,455	**6.2.4**
			(3,345,844,347)			(928,191,431)	**6.2.5**
Coal Depreciable Life Update							
Adjustment to Expense:							
Depreciation Expense - UE-399	403SP	3	(3,108,984)	SG	27.756%	(862,916)	**6.2.40**
Depreciation Expense - UE-433	403SP	3	(111,036,332)	SG	27.756%	(30,818,772)	**6.2.41**
Adjustment to Reserve:							
Depreciation Reserve - UE-399	108SP	3	6,217,969	SG	27.756%	1,725,833	**6.2.40**
Depreciation Reserve - UE-433	108SP	3	222,072,664	SG	27.756%	61,637,544	**6.2.41**

This adjustment steps forward the depreciation reserve to a December 2027 13-month average level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the December 2027 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2025 to December 31, 2027

This pro forma adjustment also includes the change in depreciation expense and reserve from UE-399 which aligned the depreciation lives with the 2021 IRP retirement dates for the following coal fired plants: Colstrip, Craig 2, and Hayden 1 & 2. This adjustment also includes the change in depreciation expense and reserve to align the depreciation lives with Order No. 24-447 in Docket UE-433 for the following coal fired plants: Dave Johnston Units 1-4, Naughton 1 & 2, and Jim Bridger Units 1-4.

PacifiCorp
Oregon General Rate Case - December 2027
Depreciation and Amortization Reserve Summary

Description	Account	2020P Factor	Year End 12 ME June 2025 Reserve	13 Month Average Test Period Reserve	Adjustment to Test Period
DEPRECIATION RESERVE					
Steam Production Plant:					
Pre-merger Pacific	108SP	SG	(869,988,425)	(967,591,840)	(97,603,415)
Pre-merger Utah	108SP	SG	(791,448,358)	(886,907,518)	(95,459,160)
Post-merger	108SP	SG	(2,724,841,774)	(4,488,247,535)	(1,763,405,762)
Oregon	108SP	OR	(1,070,726)	(1,070,726)	-
Washington	108SP	WA	(16,063,271)	(16,063,271)	-
California	108SP	CA	(1,856,680)	(1,856,680)	-
Utah	108SP	UT	(76,741,331)	(76,741,331)	-
Idaho	108SP	ID	(8,297,223)	(8,297,223)	-
Eastern Wyoming	108SP	WYP	(22,675,360)	(22,675,360)	-
Western Wyoming	108SP	WYU	-	-	-
Post-merger	108SP	OTHER	-	-	-
Total Steam Plant			(4,512,983,148)	(6,469,451,484)	(1,956,468,337)
Hydro Production Plant:					
Pre-merger Pacific	108HP	SG	(138,454,258)	(145,860,861)	(7,406,603)
Pre-merger Utah	108HP	SG	(34,137,913)	(36,252,185)	(2,114,272)
Post-merger	108HP	SG	(7,198,384)	(8,372,222)	(1,173,838)
Post-merger	108HP	SG-P	(230,266,414)	(277,475,302)	(47,208,888)
Post-merger	108HP	SG-U	(92,261,703)	(106,694,211)	(14,432,508)
Total Hydro Plant			(502,318,671)	(574,654,781)	(72,336,110)
Solar Production Plant:					
Oregon	108XP	OR	(10,885)	(250,088)	(239,203)
Utah	108XP	UT	(84,821)	(133,169)	(48,348)
Post-merger	108XP	SG	(67,257)	(67,257)	-
System	108XP	OTHER	-	-	-
Total Solar Plant			(162,962)	(450,514)	(287,551)
Wind Production Plant:					
Oregon	108WP	OR	-	-	-
Utah	108WP	UT	-	-	-
Post-merger	108WP	SG	(146,079,229)	(453,594,625)	(307,515,395.65)
System	108WP	OTHER	-	-	-
Total Wind Plant			(146,079,229)	(453,594,625)	(307,515,396)
Renewable Production Plant:					
Oregon	108RP	OR	-	-	-
Utah	108RP	UT	-	-	-
Post-merger	108RP	SG	(101,699,389)	(107,717,078)	(6,017,689)
System	108RP	OTHER	-	-	-
Total Renewable Plant			(101,699,389)	(107,717,078)	(6,017,689)
Other Production Plant:					
Pre-merger Pacific	108OP	SG-W	-	-	-
Pre-merger Utah	108OP	SG	-	-	-
Post-merger	108OP	SG	(676,971,232)	(766,750,632)	(89,779,400)
Oregon	108OP	OR	-	-	-
Utah	108OP	UT	-	-	-
System	108OP	SG	(58,762,728)	(66,709,588)	(7,946,861)
Total Other Plant			(735,733,959)	(833,460,220)	(97,726,261)

PacifiCorp
Oregon General Rate Case - December 2027
Depreciation and Amortization Reserve Summary

Description	Account	2020P Factor	Year End 12 ME June 2025 Reserve	13 Month Average Test Period Reserve	Adjustment to Test Period
Transmission Plant:					
California	108TP	CA	-	-	-
Oregon	108TP	OR	-	(3,955,388)	(3,955,388)
Washington	108TP	WA	-	-	-
Eastern Wyoming	108TP	WYP	-	-	-
Western Wyoming	108TP	WYU	-	-	-
Utah	108TP	UT	-	-	-
Idaho	108TP	ID	-	-	-
System	108TP	SG	(360,621,844)	(373,105,225)	(12,483,380)
Pre-merger Utah	108TP	SG	(434,328,458)	(448,335,704)	(14,007,246)
Post-merger	108TP	SG	(1,822,660,315)	(2,167,321,401)	(344,661,086)
System	108TP	OTHER	-	-	-
Total Transmission Plant			(2,617,610,617)	(2,988,762,330)	(371,151,713)
Distribution Plant:					
California	108364	CA	(165,589,695)	(194,365,011)	(28,775,316)
Oregon	108364	OR	(1,245,390,255)	(1,358,283,318)	(112,893,063)
Washington	108364	WA	(323,884,569)	(352,676,756)	(28,792,187)
Eastern Wyoming	108364	WYP	(353,193,977)	(389,091,675)	(35,897,698)
Utah	108364	UT	(1,274,847,153)	(1,446,148,347)	(171,301,194)
Idaho	108364	ID	(180,832,709)	(196,426,924)	(15,594,214)
Western Wyoming	108364	WYU	(74,866,447)	(82,748,670)	(7,882,223)
Pre-merger Pacific	108363	SG	-	-	-
Pre-merger Utah	108363	SG	-	-	-
System	108363	SNPD	(28,952,540)	(31,082,684)	(2,130,144)
System	108363	CN	(10,802,634)	(10,802,634)	-
System	108363	SO	-	-	-
System	108363	SG	-	-	-
System	108363	OTHER	-	-	-
Total Distribution Plant			(3,658,359,979)	(4,061,626,019)	(403,266,040)
Energy Storage Plant:					
California	108ES	CA	-	-	-
Oregon	108ES	OR	-	-	-
Washington	108ES	WA	-	-	-
Eastern Wyoming	108ES	WYP	-	-	-
Utah	108ES	UT	-	-	-
Idaho	108ES	ID	-	-	-
Western Wyoming	108ES	WYU	-	-	-
System	108ES	CN	-	-	-
System	108ES	SNPD	-	-	-
System	108ES	SG	-	-	-
System	108ES	SO	-	-	-
System	108ES	OTHER	-	-	-
Total Energy Storage Plant			-	-	-

PacifiCorp
Oregon General Rate Case - December 2027
Depreciation and Amortization Reserve Summary

Description	Account	2020P Factor	Year End 12 ME June 2025 Reserve	13 Month Average Test Period Reserve	Adjustment to Test Period
General Plant:					
California	108GP	CA	(6,705,684)	(7,232,465)	(526,781)
Oregon	108GP	OR	(68,887,615)	(68,914,909)	(27,294)
Washington	108GP	WA	(20,186,615)	(21,349,599)	(1,162,984)
Eastern Wyoming	108GP	WYP	(24,592,610)	(28,576,025)	(3,983,415)
Utah	108GP	UT	(97,753,708)	(108,718,263)	(10,964,555)
Idaho	108GP	ID	(18,243,919)	(20,489,112)	(2,245,193)
Western Wyoming	108GP	WYU	(6,805,241)	(7,693,112)	(887,871)
Pre-merger Pacific	108GP	DGP	(482,941)	(317,488)	165,454
Pre-merger Utah	108GP	DGU	(1,614,980)	(1,101,971)	513,009
Post-merger	108GP	SG	(60,660,708)	(58,468,626)	2,192,082
System	108GP	SO	(513,990,979)	(617,485,209)	(103,494,230)
System	108GP	SG	(147,517)	(152,709)	(5,193)
System	108GP	SG	-	-	-
System	108GP	SNPD	-	-	-
Customer Service	108GP	CN	(209,784,783)	(222,176,030)	(12,391,247)
Fuel Related	108GP	SE	(1,598,780)	(1,561,399)	37,381
Total General Plant			(1,031,456,080)	(1,164,236,916)	(132,780,837)
Mining Plant:					
Coal Mine	108MP	SE	-	-	-
Total Mining Plant			-	-	-
Total Depreciation Reserve			**(13,306,404,034)**	**(16,657,909,354)**	**(3,351,505,320)**
AMORTIZATION RESERVE					
Intangible Plant:					
California	111IP	CA	-	3,021	3,021
Customer Service	111IP	CN	-	3,178,870	3,178,870
Pre-merger Pacific	111IP	DGP	-	-	-
Idaho	111IP	ID	(1,000,000)	(995,018)	4,982
Oregon	111IP	OR	(157,116)	(170,171)	(13,054)
Fuel Related	111IP	SE	-	-	-
Post-merger	111IP	SG	(83,406,888)	(88,082,469)	(4,675,580)
Hydro Relicensing	111IP	SG-P	(51,222,738)	(56,588,688)	(5,365,950)
Hydro Relicensing	111IP	SG-U	(6,961,944)	(7,148,220)	(186,276)
Pre-merger Utah	111IP	DGU	(446,940)	(428,370)	18,570
General Office	111IP	SO	-	13,908,637	13,908,637
Utah	111IP	UT	(396,779)	(576,883)	(180,104)
Washington	111IP	WA	-	5,175	5,175
Eastern Wyoming	111IP	WYP	(408,176)	(386,986)	21,190
Western Wyoming	111IP	WYU	-	-	-
Total Intangible Plant			(144,000,582)	(137,281,100)	6,719,482
Hydro Production Plant:					
Pre-merger Pacific	111HP	DGP	-	-	-
Pre-merger Utah	111HP	DGU	-	-	-
Post-merger	111HP	SG	-	-	-
Post-merger Pacific	111HP	SG-P	(4,393,786)	(5,023,251)	(629,465)
Post-merger Utah	111HP	SG-U	-	-	-
Total Hydro Plant			(4,393,786)	(5,023,251)	(629,465)

PacifiCorp
Oregon General Rate Case - December 2027
Depreciation and Amortization Reserve Summary

Description	Account	2020P Factor	Year End 12 ME June 2025 Reserve	13 Month Average Test Period Reserve	Adjustment to Test Period
Solar Production Plant:					
Oregon	111XP	OR	(279,419)	(279,419)	-
Utah	111XP	UT	-	-	-
Post-merger	111XP	SG	-	-	-
System	111XP	OTHER	-	-	-
Total Solar Plant			(279,419)	(279,419)	-
Wind Production Plant:					
Oregon	111WP	OR	-	-	-
Utah	111WP	UT	-	-	-
Post-merger	111WP	SG	-	-	-
System	111WP	OTHER	-	-	-
Total Wind Plant					
Renewable Production Plant:					
Oregon	111RP	OR	-	-	-
Utah	111RP	UT	-	-	-
Post-merger	111RP	SG	-	-	-
System	111RP	OTHER	-	-	-
Total Renewable Plant			-	-	-
Other Production Plant:					
Oregon	111OP	OR	-	-	-
Total Other Plant			-	-	-
General Plant:					
California	111GP	CA	(512,304)	(512,304)	-
General Office	111GP	CN	-	-	-
Idaho	111GP	ID	(333,771)	(333,771)	-
Oregon	111GP	OR	(5,253,064)	(5,403,828)	(150,764)
General Office	111GP	SO	(1,875,315)	(1,943,674)	(68,359)
Utah	111GP	UT	(33,127)	(33,127)	-
Washington	111GP	WA	(2,264,731)	(2,467,724)	(202,993)
Eastern Wyoming	111GP	WYP	(4,738,247)	(4,745,174)	(6,927)
Western Wyoming	111GP	WYU	-	-	-
Total General Plant			(15,010,559)	(15,439,603)	(429,044)
Total Amortization Reserve			**(163,684,346)**	**(14,927,298)**	**(429,044)**
Total Depreciation & Amortization Reserve			**(13,470,088,380)**	**(16,815,932,727)**	**(3,345,844,347)**
				Ref. 6.2.36	**Ref 6.2.1**

PacifiCorp
Oregon General Rate Case - December 2027
June 2025 - December 2027 Depreciation & Amortization Reserve

Description	Account	2020P Factor	Adjusted Reserve Balance Jun 2025	Adjustments	Adjusted Reserve Balance Jul 2025	Adjustments	Adjusted Reserve Balance Aug 2025	Adjustments	Adjusted Reserve Balance Sep 2025	Adjustments	Adjusted Reserve Balance Oct 2025
DEPRECIATION RESERVE											
Steam Production Plant:											
Pre-merger Pacific	108SP	SG	(869,988,425)	(4,049,451)	(874,037,877)	(4,048,674)	(878,086,551)	(4,047,897)	(882,134,448)	(4,047,119)	(886,181,567)
Pre-merger Utah	108SP	SG	(791,448,358)	(3,946,007)	(795,394,365)	(3,944,635)	(799,339,000)	(3,943,262)	(803,282,262)	(3,941,889)	(807,224,151)
Post-merger	108SP	SG	(3,906,424,653)	(23,430,791)	(3,929,855,444)	(23,441,363)	(3,953,296,807)	(23,446,602)	(3,976,743,410)	(23,442,313)	(4,000,185,723)
Oregon	108SP	OR	(1,070,726)	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)
Washington	108SP	WA	(16,063,271)	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)
California	108SP	CA	(1,856,680)	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)
Utah	108SP	UT	(76,741,331)	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)
Idaho	108SP	ID	(8,297,223)	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)
Eastern Wyoming	108SP	WYP	(22,675,360)	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)
Western Wyoming	108SP	WYU	-	-	-	-	-	-	-	-	-
Post-merger	108SP	OTHER	-	-	-	-	-	-	-	-	-
Total Steam Plant			(5,694,566,027)	(31,426,250)	(5,725,992,277)	(31,434,672)	(5,757,426,949)	(31,437,761)	(5,788,864,710)	(31,431,322)	(5,820,296,032)
Hydro Production Plant:											
Pre-merger Pacific	108HP	SG	(138,454,258)	(304,989)	(138,759,247)	(304,932)	(139,064,179)	(304,875)	(139,369,054)	(304,818)	(139,673,872)
Pre-merger Utah	108HP	SG	(34,137,913)	(85,910)	(34,223,823)	(85,859)	(34,309,682)	(85,808)	(34,395,491)	(85,758)	(34,481,248)
Post-merger	108HP	SG	(7,198,384)	(48,910)	(7,247,294)	(48,910)	(7,296,204)	(48,910)	(7,345,114)	(48,910)	(7,394,023)
Post-merger	108HP	SG-P	(230,266,414)	(1,703,442)	(231,969,856)	(1,706,027)	(233,675,882)	(1,710,967)	(235,386,849)	(1,713,847)	(237,100,696)
Post-merger	108HP	SG-U	(92,261,703)	(559,902)	(92,821,605)	(571,430)	(93,393,034)	(493,302)	(93,886,337)	(244,373)	(94,130,710)
Total Hydro Plant			(502,318,671)	(2,703,153)	(505,021,824)	(2,717,157)	(507,738,982)	(2,643,863)	(510,382,844)	(2,397,705)	(512,780,549)
Solar Production Plant:											
Oregon	108XP	OR	(10,885)	(9,315)	(20,200)	(9,767)	(29,967)	(9,767)	(39,734)	(9,767)	(49,502)
Utah	108XP	UT	(84,821)	(2,002)	(86,823)	(2,002)	(88,824)	(2,001)	(90,826)	(2,001)	(92,826)
Post-merger	108XP	SG	(67,257)	-	(67,257)	-	(67,257)	-	(67,257)	-	(67,257)
System	108XP	OTHER	-	-	-	-	-	-	-	-	-
Total Solar Plant			(162,962)	(11,317)	(174,279)	(11,769)	(186,048)	(11,768)	(197,817)	(11,768)	(209,585)
Wind Production Plant:											
Oregon	108WP	OR	-	-	-	-	-	-	-	-	-
Utah	108WP	UT	-	-	-	-	-	-	-	-	-
Post-merger	108WP	SG	(146,079,229)	(12,765,198)	(158,844,427)	(12,765,361)	(171,609,788)	(12,770,969)	(184,380,756)	(12,776,152)	(197,156,908)
System	108WP	OTHER	-	-	-	-	-	-	-	-	-
Total Wind Plant			(146,079,229)	(12,765,198)	(158,844,427)	(12,765,361)	(171,609,788)	(12,770,969)	(184,380,756)	(12,776,152)	(197,156,908)
Renewable Production Plant:											
Oregon	108RP	OR	-	-	-	-	-	-	-	-	-
Utah	108RP	UT	-	-	-	-	-	-	-	-	-
Post-merger	108RP	SG	(101,699,389)	(249,361)	(101,948,750)	(249,383)	(102,198,133)	(249,404)	(102,447,537)	(249,426)	(102,696,963)
System	108RP	OTHER	-	-	-	-	-	-	-	-	-
Total Renewable Plant			(101,699,389)	(249,361)	(101,948,750)	(249,383)	(102,198,133)	(249,404)	(102,447,537)	(249,426)	(102,696,963)

PacifiCorp
Oregon General Rate Case - December 2027
June 2025 - December 2027 Depreciation & Amortization Reserve

Description	Account	2020P Factor	Adjusted Reserve Balance Jun 2025	Adjustments	Adjusted Reserve Balance Jul 2025	Adjustments	Adjusted Reserve Balance Aug 2025	Adjustments	Adjusted Reserve Balance Sep 2025	Adjustments	Adjusted Reserve Balance Oct 2025
Other Production Plant:											
Pre-merger Pacific	108OP	SG-W	-	-	-	-	-	-	-	-	-
Pre-merger Utah	108OP	SG	-	-	-	-	-	-	-	-	-
Post-merger	108OP	SG	(676,971,232)	(3,340,034)	(680,311,265)	(3,333,636)	(683,644,901)	(3,326,750)	(686,971,651)	(3,319,987)	(690,291,638)
Oregon	108OP	OR	-	-	-	-	-	-	-	-	-
Utah	108OP	UT	-	-	-	-	-	-	-	-	-
System	108OP	SG	(58,762,728)	(328,106)	(59,090,834)	(327,986)	(59,418,820)	(327,867)	(59,746,686)	(327,747)	(60,074,433)
Total Other Plant			(735,733,959)	(3,668,140)	(739,402,099)	(3,661,622)	(743,063,721)	(3,654,616)	(746,718,338)	(3,647,733)	(750,366,071)
Transmission Plant:											
California	108TP	CA	-	-	-	-	-	-	-	-	-
Oregon	108TP	OR	-	33	33	82	115	348	463	590	1,053
Washington	108TP	WA	-	-	-	-	-	-	-	-	-
Eastern Wyoming	108TP	WYP	-	-	-	-	-	-	-	-	-
Western Wyoming	108TP	WYU	-	-	-	-	-	-	-	-	-
Utah	108TP	UT	-	-	-	-	-	-	-	-	-
Idaho	108TP	ID	-	-	-	-	-	-	-	-	-
System	108TP	SG	(360,621,844)	(498,392)	(361,120,236)	(498,152)	(361,618,388)	(497,912)	(362,116,300)	(497,672)	(362,613,972)
Pre-merger Utah	108TP	SG	(434,328,458)	(545,703)	(434,874,161)	(545,293)	(435,419,454)	(544,882)	(435,964,336)	(544,472)	(436,508,808)
Post-merger	108TP	SG	(1,822,660,315)	(13,307,665)	(1,835,967,980)	(13,355,900)	(1,849,323,880)	(13,459,685)	(1,862,783,565)	(13,575,000)	(1,876,358,565)
System	108TP	OTHER	-	-	-	-	-	-	-	-	-
Total Transmission Plant			(2,617,610,617)	(14,351,761)	(2,631,962,377)	(14,399,345)	(2,646,361,722)	(14,502,479)	(2,660,864,201)	(14,617,143)	(2,675,481,345)
Distribution Plant:											
California	108364	CA	(165,589,695)	(807,331)	(166,397,026)	(820,296)	(167,217,322)	(839,022)	(168,056,344)	(863,099)	(168,919,443)
Oregon	108364	OR	(1,245,390,255)	(3,859,704)	(1,249,249,959)	(3,887,663)	(1,253,137,622)	(3,911,434)	(1,257,049,056)	(3,939,733)	(1,260,988,789)
Washington	108364	WA	(323,884,569)	(1,087,619)	(324,972,188)	(1,088,537)	(326,060,725)	(1,089,897)	(327,150,621)	(1,092,953)	(328,243,574)
Eastern Wyoming	108364	WYP	(353,193,977)	(1,235,598)	(354,429,575)	(1,239,901)	(355,669,476)	(1,247,388)	(356,916,864)	(1,257,025)	(358,173,889)
Utah	108364	UT	(1,274,847,153)	(5,353,527)	(1,280,200,679)	(5,458,836)	(1,285,659,515)	(5,594,322)	(1,291,253,838)	(5,779,841)	(1,297,033,678)
Idaho	108364	ID	(180,832,709)	(492,331)	(181,325,040)	(496,484)	(181,821,524)	(506,943)	(182,328,467)	(516,656)	(182,845,123)
Western Wyoming	108364	WYU	(74,866,447)	(322,083)	(75,188,530)	(321,962)	(75,510,492)	(321,842)	(75,832,334)	(321,721)	(76,154,056)
Pre-merger Pacific	108363	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	108363	SG	-	-	-	-	-	-	-	-	-
System	108363	SNPD	(28,952,540)	(86,026)	(29,038,565)	(86,026)	(29,124,591)	(86,026)	(29,210,616)	(86,026)	(29,296,642)
System	108363	CN	(10,802,634)	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)
System	108363	SO	-	-	-	-	-	-	-	-	-
System	108363	SG	-	-	-	-	-	-	-	-	-
System	108363	OTHER	-	-	-	-	-	-	-	-	-
Total Distribution Plant			(3,658,359,979)	(13,244,218)	(3,671,604,197)	(13,399,704)	(3,685,003,901)	(13,596,874)	(3,698,600,776)	(13,857,052)	(3,712,457,828)
Energy Storage Plant:											
California	108ES	CA	-	-	-	-	-	-	-	-	-
Oregon	108ES	OR	-	-	-	-	-	-	-	-	-
Washington	108ES	WA	-	-	-	-	-	-	-	-	-
Eastern Wyoming	108ES	WYP	-	-	-	-	-	-	-	-	-
Utah	108ES	UT	-	-	-	-	-	-	-	-	-
Idaho	108ES	ID	-	-	-	-	-	-	-	-	-
Western Wyoming	108ES	WYU	-	-	-	-	-	-	-	-	-
System	108ES	CN	-	-	-	-	-	-	-	-	-
System	108ES	SNPD	-	-	-	-	-	-	-	-	-
System	108ES	SG	-	-	-	-	-	-	-	-	-
System	108ES	SO	-	-	-	-	-	-	-	-	-
System	108ES	OTHER	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-	-

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Description	Account	2020P Factor	Adjusted Reserve Balance Jun 2025	Adjustments	Adjusted Reserve Balance Jul 2025	Adjustments	Adjusted Reserve Balance Aug 2025	Adjustments	Adjusted Reserve Balance Sep 2025	Adjustments	Adjusted Reserve Balance Oct 2025
General Plant:											
California	108GP	CA	(6,705,684)	(14,739)	(6,720,422)	(14,693)	(6,735,115)	(14,667)	(6,749,782)	(14,707)	(6,764,489)
Oregon	108GP	OR	(68,887,615)	99,123	(68,788,492)	99,397	(68,689,095)	99,326	(68,589,769)	98,832	(68,490,936)
Washington	108GP	WA	(20,186,615)	(34,115)	(20,220,730)	(33,999)	(20,254,729)	(33,934)	(20,288,662)	(34,007)	(20,322,669)
Eastern Wyoming	108GP	WYP	(24,592,610)	(144,474)	(24,737,084)	(144,716)	(24,881,800)	(145,090)	(25,026,890)	(145,243)	(25,172,133)
Utah	108GP	UT	(97,753,708)	(372,961)	(98,126,669)	(375,492)	(98,502,162)	(376,317)	(98,878,478)	(377,111)	(99,255,589)
Idaho	108GP	ID	(18,243,919)	(80,308)	(18,324,227)	(80,352)	(18,404,580)	(80,393)	(18,484,973)	(80,480)	(18,565,453)
Western Wyoming	108GP	WYU	(6,805,241)	(34,689)	(6,839,929)	(34,669)	(6,874,598)	(34,648)	(6,909,246)	(34,628)	(6,943,875)
Pre-merger Pacific	108GP	DGP	(482,941)	8,051	(474,890)	8,059	(466,831)	8,067	(458,763)	8,076	(450,688)
Pre-merger Utah	108GP	DGU	(1,614,980)	24,997	(1,589,983)	25,026	(1,564,957)	25,055	(1,539,902)	25,084	(1,514,818)
Post-merger	108GP	SG	(60,660,708)	181,513	(60,479,195)	183,135	(60,296,061)	184,757	(60,111,304)	186,379	(59,924,925)
System	108GP	SO	(513,990,979)	(3,819,309)	(517,810,288)	(3,813,194)	(521,623,483)	(3,829,350)	(525,452,832)	(3,861,077)	(529,313,909)
System	108GP	SG	(147,517)	(179)	(147,695)	(178)	(147,873)	(177)	(148,050)	(176)	(148,226)
System	108GP	SG	-	-	-	-	-	-	-	-	-
System	108GP	SNPD	-	-	-	-	-	-	-	-	-
Customer Service	108GP	CN	(209,784,783)	(507,265)	(210,292,048)	(507,075)	(210,799,123)	(506,885)	(211,306,007)	(506,695)	(211,812,702)
Fuel Related	108GP	SE	(1,598,780)	2,979	(1,595,802)	3,020	(1,592,782)	3,061	(1,589,721)	3,102	(1,586,620)
Total General Plant			(1,031,456,080)	(4,691,375)	(1,036,147,455)	(4,685,731)	(1,040,833,186)	(4,701,195)	(1,045,534,380)	(4,732,651)	(1,050,267,031)
Mining Plant:											
Coal Mine	108MP	SE	-	-	-	-	-	-	-	-	-
Total Mining Plant			-	-	-	-	-	-	-	-	-
Total Depreciation Reserve			(14,487,986,913)	(83,110,739)	(14,571,097,653)	(83,324,661)	(14,654,422,314)	(83,568,582)	(14,737,990,896)	(83,720,363)	(14,821,711,259)
AMORTIZATION RESERVE											
Intangible Plant:											
California	111IP	CA	-	147	147	147	294	147	441	147	588
Customer Service	111IP	CN	-	154,776	154,776	154,776	309,553	154,776	464,329	154,776	619,106
Pre-merger Pacific	111IP	DGP	-	-	-	-	-	-	-	-	-
Idaho	111IP	ID	(1,000,000)	243	(999,757)	243	(999,515)	243	(999,272)	243	(999,030)
Oregon	111IP	OR	(157,116)	(512)	(157,628)	(512)	(158,140)	(512)	(158,651)	(512)	(159,163)
Fuel Related	111IP	SE	-	-	-	-	-	-	-	-	-
Post-merger	111IP	SG	(83,406,888)	(157,645)	(83,564,533)	(156,907)	(83,721,440)	(156,169)	(83,877,608)	(155,431)	(84,033,039)
Hydro Relicensing	111IP	SG-P	(51,222,738)	(223,581)	(51,446,319)	(223,581)	(51,669,901)	(223,581)	(51,893,482)	(223,581)	(52,117,063)
Hydro Relicensing	111IP	SG-U	(6,961,944)	(5,962)	(6,967,906)	(5,931)	(6,973,837)	(5,900)	(6,979,737)	(5,869)	(6,985,606)
Pre-merger Utah	111IP	DGU	(446,940)	1,020	(445,920)	1,024	(444,896)	1,029	(443,868)	1,033	(442,834)
General Office	111IP	SO	-	677,200	677,200	677,200	1,354,399	677,200	2,031,599	677,200	2,708,798
Utah	111IP	UT	(396,779)	(7,451)	(404,230)	(7,450)	(411,681)	(7,450)	(419,131)	(7,450)	(426,580)
Washington	111IP	WA	-	252	252	252	504	252	756	252	1,008
Eastern Wyoming	111IP	WYP	(408,176)	1,775	(406,401)	1,782	(404,619)	1,788	(402,832)	1,794	(401,038)
Western Wyoming	111IP	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant			(144,000,582)	440,262	(143,560,320)	441,042	(143,119,278)	441,822	(142,677,455)	442,603	(142,234,853)

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Description	Account	2020P Factor	Adjusted Reserve Balance Jun 2025	Adjustments	Adjusted Reserve Balance Jul 2025	Adjustments	Adjusted Reserve Balance Aug 2025	Adjustments	Adjusted Reserve Balance Sep 2025	Adjustments	Adjusted Reserve Balance Oct 2025
Hydro Production Plant:											
Pre-merger Pacific	111HP	DGP	-	-	-	-	-	-	-	-	-
Pre-merger Utah	111HP	DGU	-	-	-	-	-	-	-	-	-
Post-merger	111HP	SG	-	-	-	-	-	-	-	-	-
Post-merger Pacific	111HP	SG-P	(4,393,786)	(26,228)	(4,420,014)	(26,228)	(4,446,241)	(26,228)	(4,472,469)	(26,228)	(4,498,697)
Post-merger Utah	111HP	SG-U	-	-	-	-	-	-	-	-	-
Total Hydro Plant			(4,393,786)	(26,228)	(4,420,014)	(26,228)	(4,446,241)	(26,228)	(4,472,469)	(26,228)	(4,498,697)
Solar Production Plant:											
Oregon	111XP	OR	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Utah	111XP	UT	-	-	-	-	-	-	-	-	-
Post-merger	111XP	SG	-	-	-	-	-	-	-	-	-
System	111XP	OTHER	-	-	-	-	-	-	-	-	-
Total Solar Plant			(279,419)	-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Wind Production Plant:											
Oregon	111WP	OR	-	-	-	-	-	-	-	-	-
Utah	111WP	UT	-	-	-	-	-	-	-	-	-
Post-merger	111WP	SG	-	-	-	-	-	-	-	-	-
System	111WP	OTHER	-	-	-	-	-	-	-	-	-
Total Wind Plant			-	-	-	-	-	-	-	-	-
Renewable Production Plant:											
Oregon	111RP	OR	-	-	-	-	-	-	-	-	-
Utah	111RP	UT	-	-	-	-	-	-	-	-	-
Post-merger	111RP	SG	-	-	-	-	-	-	-	-	-
System	111RP	OTHER	-	-	-	-	-	-	-	-	-
Total Renewable Plant			-	-	-	-	-	-	-	-	-
Other Production Plant:											
Oregon	111OP	OR	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-
General Plant:											
California	111GP	CA	(512,304)	-	(512,304)	-	(512,304)	-	(512,304)	-	(512,304)
General Office	111GP	CN	-	-	-	-	-	-	-	-	-
Idaho	111GP	ID	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)
Oregon	111GP	OR	(5,253,064)	(6,282)	(5,259,346)	(6,282)	(5,265,628)	(6,282)	(5,271,910)	(6,282)	(5,278,191)
General Office	111GP	SO	(1,875,315)	(2,848)	(1,878,163)	(2,848)	(1,881,012)	(2,848)	(1,883,860)	(2,848)	(1,886,708)
Utah	111GP	UT	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)
Washington	111GP	WA	(2,264,731)	(8,458)	(2,273,189)	(8,458)	(2,281,647)	(8,458)	(2,290,105)	(8,458)	(2,298,563)
Eastern Wyoming	111GP	WYP	(4,738,247)	(289)	(4,738,536)	(289)	(4,738,825)	(289)	(4,739,113)	(289)	(4,739,402)
Western Wyoming	111GP	WYU	-	-	-	-	-	-	-	-	-
Total General Plant			(15,010,559)	(17,877)	(15,028,436)	(17,877)	(15,046,312)	(17,877)	(15,064,189)	(17,877)	(15,082,066)
Total Amortization Reserve			(163,684,346)	396,158	(163,288,189)	396,938	(162,891,251)	397,718	(162,493,533)	398,498	(162,095,035)
Total Depreciation & Amortization Reserve			(14,651,671,260)	(82,714,582)	(14,734,385,841)	(82,927,724)	(14,817,313,565)	(83,170,864)	(14,900,484,429)	(83,321,865)	(14,983,806,294)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Nov 2025	Adjustments	Adjusted Reserve Balance Dec 2025	Adjustments	Adjusted Reserve Balance Jan 2026	Adjustments	Adjusted Reserve Balance Feb 2026
DEPRECIATION RESERVE										
Steam Production Plant:										
Pre-merger Pacific	108SP	SG	(4,046,342)	(890,227,909)	(4,045,565)	(894,273,474)	(4,044,787)	(898,318,261)	(4,044,010)	(902,362,272)
Pre-merger Utah	108SP	SG	(3,940,517)	(811,164,668)	(3,939,144)	(815,103,812)	(3,937,772)	(819,041,584)	(3,936,399)	(822,977,983)
Post-merger	108SP	SG	(23,443,304)	(4,023,629,026)	(23,462,420)	(4,047,091,446)	(23,472,948)	(4,070,564,395)	(23,463,038)	(4,094,027,433)
Oregon	108SP	OR	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)
Washington	108SP	WA	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)
California	108SP	CA	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)
Utah	108SP	UT	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)
Idaho	108SP	ID	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)
Eastern Wyoming	108SP	WYP	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)
Western Wyoming	108SP	WYU	-	-	-	-	-	-	-	-
Post-merger	108SP	OTHER	-	-	-	-	-	-	-	-
Total Steam Plant			(31,430,163)	(5,851,726,195)	(31,447,129)	(5,883,173,323)	(31,455,507)	(5,914,628,831)	(31,443,447)	(5,946,072,278)
Hydro Production Plant:										
Pre-merger Pacific	108HP	SG	(304,761)	(139,978,633)	(304,704)	(140,283,337)	(304,647)	(140,587,985)	(304,590)	(140,892,575)
Pre-merger Utah	108HP	SG	(85,707)	(34,566,955)	(85,656)	(34,652,611)	(85,605)	(34,738,216)	(85,554)	(34,823,770)
Post-merger	108HP	SG	(48,910)	(7,442,933)	(48,910)	(7,491,843)	(48,910)	(7,540,753)	(48,910)	(7,589,663)
Post-merger	108HP	SG-P	(1,731,362)	(238,832,058)	(1,753,151)	(240,585,209)	(1,800,614)	(242,385,823)	(1,834,030)	(244,219,853)
Post-merger	108HP	SG-U	(314,031)	(94,444,741)	(472,002)	(94,916,742)	(592,336)	(95,509,078)	(591,977)	(96,101,055)
Total Hydro Plant			(2,484,771)	(515,265,320)	(2,664,422)	(517,929,743)	(2,832,112)	(520,761,855)	(2,865,061)	(523,626,916)
Solar Production Plant:										
Oregon	108XP	OR	(9,767)	(59,269)	(9,767)	(69,036)	(9,767)	(78,804)	(9,767)	(88,571)
Utah	108XP	UT	(2,000)	(94,826)	(2,000)	(96,826)	(1,999)	(98,825)	(1,999)	(100,824)
Post-merger	108XP	SG	-	(67,257)	-	(67,257)	-	(67,257)	-	(67,257)
System	108XP	OTHER	-	-	-	-	-	-	-	-
Total Solar Plant			(11,767)	(221,352)	(11,767)	(233,119)	(11,767)	(244,886)	(11,766)	(256,652)
Wind Production Plant:										
Oregon	108WP	OR	-	-	-	-	-	-	-	-
Utah	108WP	UT	-	-	-	-	-	-	-	-
Post-merger	108WP	SG	(12,775,795)	(209,932,703)	(12,790,307)	(222,723,010)	(12,804,819)	(235,527,830)	(12,804,462)	(248,332,291)
System	108WP	OTHER	-	-	-	-	-	-	-	-
Total Wind Plant			(12,775,795)	(209,932,703)	(12,790,307)	(222,723,010)	(12,804,819)	(235,527,830)	(12,804,462)	(248,332,291)
Renewable Production Plant:										
Oregon	108RP	OR	-	-	-	-	-	-	-	-
Utah	108RP	UT	-	-	-	-	-	-	-	-
Post-merger	108RP	SG	(249,686)	(102,946,649)	(249,946)	(103,196,595)	(249,968)	(103,446,562)	(249,990)	(103,696,553)
System	108RP	OTHER	-	-	-	-	-	-	-	-
Total Renewable Plant			(249,686)	(102,946,649)	(249,946)	(103,196,595)	(249,968)	(103,446,562)	(249,990)	(103,696,553)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Nov 2025	Adjustments	Adjusted Reserve Balance Dec 2025	Adjustments	Adjusted Reserve Balance Jan 2026	Adjustments	Adjusted Reserve Balance Feb 2026
Other Production Plant:										
Pre-merger Pacific	108OP	SG-W	-	-	-	-	-	-	-	-
Pre-merger Utah	108OP	SG	-	-	-	-	-	-	-	-
Post-merger	108OP	SG	(3,316,565)	(693,608,203)	(3,322,032)	(696,930,235)	(3,324,253)	(700,254,489)	(3,317,439)	(703,571,928)
Oregon	108OP	OR	-	-	-	-	-	-	-	-
Utah	108OP	UT	-	-	-	-	-	-	-	-
System	108OP	SG	(327,627)	(60,402,060)	(327,507)	(60,729,568)	(327,388)	(61,056,956)	(327,268)	(61,384,224)
Total Other Plant			(3,644,193)	(754,010,264)	(3,649,539)	(757,659,803)	(3,651,641)	(761,311,444)	(3,644,707)	(764,956,151)
Transmission Plant:										
California	108TP	CA	-	-	-	-	-	-	-	-
Oregon	108TP	OR	580	1,634	(617)	1,017	(10,983)	(9,966)	(22,027)	(31,993)
Washington	108TP	WA	-	-	-	-	-	-	-	-
Eastern Wyoming	108TP	WYP	-	-	-	-	-	-	-	-
Western Wyoming	108TP	WYU	-	-	-	-	-	-	-	-
Utah	108TP	UT	-	-	-	-	-	-	-	-
Idaho	108TP	ID	-	-	-	-	-	-	-	-
System	108TP	SG	(497,432)	(363,111,405)	(497,192)	(363,608,597)	(496,952)	(364,105,549)	(496,712)	(364,602,261)
Pre-merger Utah	108TP	SG	(544,061)	(437,052,869)	(543,651)	(437,596,520)	(543,240)	(438,139,760)	(542,830)	(438,682,589)
Post-merger	108TP	SG	(13,657,227)	(1,890,015,792)	(13,746,933)	(1,903,762,725)	(13,809,144)	(1,917,571,869)	(13,839,121)	(1,931,410,989)
System	108TP	OTHER	-	-	-	-	-	-	-	-
Total Transmission Plant			(14,698,720)	(2,690,180,065)	(14,787,776)	(2,704,967,841)	(14,849,336)	(2,719,817,177)	(14,878,662)	(2,734,695,840)
Distribution Plant:										
California	108364	CA	(902,469)	(169,821,911)	(947,835)	(170,769,746)	(972,604)	(171,742,350)	(981,819)	(172,724,169)
Oregon	108364	OR	(3,973,260)	(1,264,962,049)	(3,998,801)	(1,268,960,850)	(4,012,475)	(1,272,973,325)	(4,208,245)	(1,277,181,570)
Washington	108364	WA	(1,095,244)	(329,338,819)	(1,098,153)	(330,436,971)	(1,101,623)	(331,538,594)	(1,103,406)	(332,642,000)
Eastern Wyoming	108364	WYP	(1,265,570)	(359,439,459)	(1,310,139)	(360,749,598)	(1,352,980)	(362,102,578)	(1,358,052)	(363,460,630)
Utah	108364	UT	(5,962,009)	(1,302,995,687)	(6,141,396)	(1,309,137,083)	(6,258,735)	(1,315,395,818)	(6,317,921)	(1,321,713,739)
Idaho	108364	ID	(520,044)	(183,365,167)	(529,822)	(183,894,989)	(539,431)	(184,434,420)	(542,613)	(184,977,034)
Western Wyoming	108364	WYU	(321,601)	(76,475,656)	(321,480)	(76,797,136)	(321,359)	(77,118,496)	(321,239)	(77,439,735)
Pre-merger Pacific	108363	SG	-	-	-	-	-	-	-	-
Pre-merger Utah	108363	SG	-	-	-	-	-	-	-	-
System	108363	SNPD	(86,026)	(29,382,668)	(86,026)	(29,468,693)	(86,026)	(29,554,719)	(86,026)	(29,640,744)
System	108363	CN	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)
System	108363	SO	-	-	-	-	-	-	-	-
System	108363	SG	-	-	-	-	-	-	-	-
System	108363	OTHER	-	-	-	-	-	-	-	-
Total Distribution Plant			(14,126,222)	(3,726,584,050)	(14,433,652)	(3,741,017,702)	(14,645,233)	(3,755,662,934)	(14,919,320)	(3,770,582,255)
Energy Storage Plant:										
California	108ES	CA	-	-	-	-	-	-	-	-
Oregon	108ES	OR	-	-	-	-	-	-	-	-
Washington	108ES	WA	-	-	-	-	-	-	-	-
Eastern Wyoming	108ES	WYP	-	-	-	-	-	-	-	-
Utah	108ES	UT	-	-	-	-	-	-	-	-
Idaho	108ES	ID	-	-	-	-	-	-	-	-
Western Wyoming	108ES	WYU	-	-	-	-	-	-	-	-
System	108ES	CN	-	-	-	-	-	-	-	-
System	108ES	SNPD	-	-	-	-	-	-	-	-
System	108ES	SG	-	-	-	-	-	-	-	-
System	108ES	SO	-	-	-	-	-	-	-	-
System	108ES	OTHER	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Nov 2025	Adjustments	Adjusted Reserve Balance Dec 2025	Adjustments	Adjusted Reserve Balance Jan 2026	Adjustments	Adjusted Reserve Balance Feb 2026
General Plant:										
California	108GP	CA	(14,793)	(6,779,282)	(14,883)	(6,794,165)	(14,911)	(6,809,077)	(14,875)	(6,823,951)
Oregon	108GP	OR	98,511	(68,392,426)	97,970	(68,294,455)	97,919	(68,196,537)	98,596	(68,097,940)
Washington	108GP	WA	(34,164)	(20,356,833)	(34,329)	(20,391,162)	(34,370)	(20,425,532)	(34,276)	(20,459,809)
Eastern Wyoming	108GP	WYP	(145,394)	(25,317,526)	(145,546)	(25,463,072)	(145,718)	(25,608,790)	(145,896)	(25,754,686)
Utah	108GP	UT	(377,860)	(99,633,449)	(378,571)	(100,012,021)	(379,030)	(100,391,051)	(379,201)	(100,770,251)
Idaho	108GP	ID	(80,604)	(18,646,057)	(80,764)	(18,726,821)	(80,858)	(18,807,679)	(80,879)	(18,888,558)
Western Wyoming	108GP	WYU	(34,608)	(6,978,483)	(34,588)	(7,013,072)	(34,568)	(7,047,640)	(34,548)	(7,082,188)
Pre-merger Pacific	108GP	DGP	8,084	(442,604)	8,092	(434,512)	8,100	(426,412)	8,108	(418,303)
Pre-merger Utah	108GP	DGU	25,113	(1,489,706)	25,141	(1,464,564)	25,170	(1,439,394)	25,199	(1,414,195)
Post-merger	108GP	SG	188,001	(59,736,925)	189,623	(59,547,302)	191,245	(59,356,057)	192,867	(59,163,190)
System	108GP	SO	(3,901,887)	(533,215,796)	(3,972,221)	(537,188,016)	(4,020,819)	(541,208,835)	(4,030,438)	(545,239,273)
System	108GP	SG	(175)	(148,401)	(174)	(148,575)	(173)	(148,748)	(172)	(148,920)
System	108GP	SG	-	-	-	-	-	-	-	-
System	108GP	SNPD	-	-	-	-	-	-	-	-
Customer Service	108GP	CN	(506,504)	(212,319,206)	(506,314)	(212,825,520)	(506,124)	(213,331,644)	(505,934)	(213,837,578)
Fuel Related	108GP	SE	3,143	(1,583,477)	3,184	(1,580,294)	3,224	(1,577,069)	3,265	(1,573,804)
Total General Plant			(4,773,139)	(1,055,040,171)	(4,843,381)	(1,059,883,552)	(4,890,913)	(1,064,774,465)	(4,898,183)	(1,069,672,648)
Mining Plant:										
Coal Mine	108MP	SE	-	-	-	-	-	-	-	-
Total Mining Plant			-	-	-	-	-	-	-	-
Total Depreciation Reserve			(84,193,876)	(14,905,905,135)	(84,878,536)	(14,990,783,671)	(85,402,279)	(15,076,185,950)	(85,737,626)	(15,161,923,577)
AMORTIZATION RESERVE										
Intangible Plant:										
California	111IP	CA	147	736	147	883	147	1,030	147	1,177
Customer Service	111IP	CN	154,776	773,882	154,776	928,659	154,776	1,083,435	154,776	1,238,212
Pre-merger Pacific	111IP	DGP	-	-	-	-	-	-	-	-
Idaho	111IP	ID	243	(998,787)	243	(998,545)	243	(998,302)	243	(998,059)
Oregon	111IP	OR	(512)	(159,675)	(512)	(160,187)	(512)	(160,698)	(512)	(161,210)
Fuel Related	111IP	SE	-	-	-	-	-	-	-	-
Post-merger	111IP	SG	(154,693)	(84,187,732)	(153,955)	(84,341,687)	(153,217)	(84,494,904)	(152,479)	(84,647,384)
Hydro Relicensing	111IP	SG-P	(223,581)	(52,340,644)	(223,581)	(52,564,225)	(223,581)	(52,787,807)	(223,581)	(53,011,388)
Hydro Relicensing	111IP	SG-U	(5,838)	(6,991,443)	(5,807)	(6,997,250)	(5,775)	(7,003,025)	(5,744)	(7,008,770)
Pre-merger Utah	111IP	DGU	1,038	(441,797)	1,042	(440,755)	1,046	(439,708)	1,051	(438,657)
General Office	111IP	SO	677,200	3,385,998	677,200	4,063,197	677,200	4,740,397	677,200	5,417,596
Utah	111IP	UT	(7,449)	(434,030)	(7,449)	(441,478)	(7,448)	(448,927)	(7,448)	(456,375)
Washington	111IP	WA	252	1,260	252	1,512	252	1,764	252	2,016
Eastern Wyoming	111IP	WYP	1,800	(399,237)	1,806	(397,431)	1,813	(395,618)	1,819	(393,799)
Western Wyoming	111IP	WYU	-	-	-	-	-	-	-	-
Total Intangible Plant			443,383	(141,791,470)	444,163	(141,347,307)	444,943	(140,902,364)	445,723	(140,456,641)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Nov 2025	Adjustments	Adjusted Reserve Balance Dec 2025	Adjustments	Adjusted Reserve Balance Jan 2026	Adjustments	Adjusted Reserve Balance Feb 2026
Hydro Production Plant:										
Pre-merger Pacific	111HP	DGP	-	-	-	-	-	-	-	-
Pre-merger Utah	111HP	DGU	-	-	-	-	-	-	-	-
Post-merger	111HP	SG	-	-	-	-	-	-	-	-
Post-merger Pacific	111HP	SG-P	(26,228)	(4,524,925)	(26,228)	(4,551,152)	(26,228)	(4,577,380)	(26,228)	(4,603,608)
Post-merger Utah	111HP	SG-U	-	-	-	-	-	-	-	-
Total Hydro Plant			(26,228)	(4,524,925)	(26,228)	(4,551,152)	(26,228)	(4,577,380)	(26,228)	(4,603,608)
Solar Production Plant:										
Oregon	111XP	OR	-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Utah	111XP	UT	-	-	-	-	-	-	-	-
Post-merger	111XP	SG	-	-	-	-	-	-	-	-
System	111XP	OTHER	-	-	-	-	-	-	-	-
Total Solar Plant			-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Wind Production Plant:										
Oregon	111WP	OR	-	-	-	-	-	-	-	-
Utah	111WP	UT	-	-	-	-	-	-	-	-
Post-merger	111WP	SG	-	-	-	-	-	-	-	-
System	111WP	OTHER	-	-	-	-	-	-	-	-
Total Wind Plant			-	-	-	-	-	-	-	-
Renewable Production Plant:										
Oregon	111RP	OR	-	-	-	-	-	-	-	-
Utah	111RP	UT	-	-	-	-	-	-	-	-
Post-merger	111RP	SG	-	-	-	-	-	-	-	-
System	111RP	OTHER	-	-	-	-	-	-	-	-
Total Renewable Plant			-	-	-	-	-	-	-	-
Other Production Plant:										
Oregon	111OP	OR	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-
General Plant:										
California	111GP	CA	-	(512,304)	-	(512,304)	-	(512,304)	-	(512,304)
General Office	111GP	CN	-	-	-	-	-	-	-	-
Idaho	111GP	ID	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)
Oregon	111GP	OR	(6,282)	(5,284,473)	(6,282)	(5,290,755)	(6,282)	(5,297,037)	(6,282)	(5,303,319)
General Office	111GP	SO	(2,848)	(1,889,557)	(2,848)	(1,892,405)	(2,848)	(1,895,253)	(2,848)	(1,898,101)
Utah	111GP	UT	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)
Washington	111GP	WA	(8,458)	(2,307,021)	(8,458)	(2,315,479)	(8,458)	(2,323,937)	(8,458)	(2,332,395)
Eastern Wyoming	111GP	WYP	(289)	(4,739,690)	(289)	(4,739,979)	(289)	(4,740,268)	(289)	(4,740,556)
Western Wyoming	111GP	WYU	-	-	-	-	-	-	-	-
Total General Plant			(17,877)	(15,099,943)	(17,877)	(15,117,820)	(17,877)	(15,135,697)	(17,877)	(15,153,573)
Total Amortization Reserve			399,278	(161,695,757)	400,058	(161,295,698)	400,839	(160,894,860)	401,619	(160,493,241)
Total Depreciation & Amortization Reserve			(83,794,598)	(15,067,600,892)	(84,478,478)	(15,152,079,370)	(85,001,441)	(15,237,080,810)	(85,336,008)	(15,322,416,818)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Mar 2026	Adjustments	Adjusted Reserve Balance Apr 2026	Adjustments	Adjusted Reserve Balance May 2026	Adjustments	Adjusted Reserve Balance Jun 2026
DEPRECIATION RESERVE										
Steam Production Plant:										
Pre-merger Pacific	108SP	SG	(4,043,233)	(906,405,504)	(4,042,455)	(910,447,960)	(4,041,678)	(914,489,638)	(4,040,901)	(918,530,538)
Pre-merger Utah	108SP	SG	(3,935,026)	(826,913,009)	(3,933,654)	(830,846,663)	(3,932,281)	(834,778,944)	(3,930,908)	(838,709,852)
Post-merger	108SP	SG	(23,458,898)	(4,117,486,331)	(23,498,494)	(4,140,984,825)	(23,596,624)	(4,164,581,449)	(23,712,486)	(4,188,293,935)
Oregon	108SP	OR	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)
Washington	108SP	WA	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)
California	108SP	CA	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)
Utah	108SP	UT	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)
Idaho	108SP	ID	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)
Eastern Wyoming	108SP	WYP	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)
Western Wyoming	108SP	WYU	-	-	-	-	-	-	-	-
Post-merger	108SP	OTHER	-	-	-	-	-	-	-	-
Total Steam Plant			(31,437,157)	(5,977,509,435)	(31,474,603)	(6,008,984,038)	(31,570,583)	(6,040,554,622)	(31,684,295)	(6,072,238,917)
Hydro Production Plant:										
Pre-merger Pacific	108HP	SG	(304,533)	(141,197,108)	(304,476)	(141,501,585)	(304,419)	(141,806,004)	(304,363)	(142,110,367)
Pre-merger Utah	108HP	SG	(85,503)	(34,909,273)	(85,453)	(34,994,726)	(85,402)	(35,080,128)	(85,351)	(35,165,479)
Post-merger	108HP	SG	(48,910)	(7,638,573)	(48,910)	(7,687,483)	(48,910)	(7,736,393)	(48,910)	(7,785,303)
Post-merger	108HP	SG-P	(1,850,269)	(246,070,122)	(1,850,047)	(247,920,169)	(1,851,393)	(249,771,562)	(1,854,532)	(251,626,094)
Post-merger	108HP	SG-U	(591,618)	(96,692,673)	(591,665)	(97,284,338)	(591,712)	(97,876,050)	(596,748)	(98,472,798)
Total Hydro Plant			(2,880,834)	(526,507,750)	(2,880,551)	(529,388,301)	(2,881,836)	(532,270,137)	(2,889,904)	(535,160,040)
Solar Production Plant:										
Oregon	108XP	OR	(9,767)	(98,338)	(9,767)	(108,106)	(9,767)	(117,873)	(9,767)	(127,640)
Utah	108XP	UT	(1,998)	(102,822)	(1,998)	(104,820)	(1,997)	(106,818)	(1,997)	(108,815)
Post-merger	108XP	SG	-	(67,257)	-	(67,257)	-	(67,257)	-	(67,257)
System	108XP	OTHER	-	-	-	-	-	-	-	-
Total Solar Plant			(11,766)	(268,418)	(11,765)	(280,183)	(11,765)	(291,947)	(11,764)	(303,712)
Wind Production Plant:										
Oregon	108WP	OR	-	-	-	-	-	-	-	-
Utah	108WP	UT	-	-	-	-	-	-	-	-
Post-merger	108WP	SG	(12,808,589)	(261,140,880)	(12,812,716)	(273,953,597)	(12,812,359)	(286,765,955)	(12,816,486)	(299,582,441)
System	108WP	OTHER	-	-	-	-	-	-	-	-
Total Wind Plant			(12,808,589)	(261,140,880)	(12,812,716)	(273,953,597)	(12,812,359)	(286,765,955)	(12,816,486)	(299,582,441)
Renewable Production Plant:										
Oregon	108RP	OR	-	-	-	-	-	-	-	-
Utah	108RP	UT	-	-	-	-	-	-	-	-
Post-merger	108RP	SG	(250,013)	(103,946,565)	(250,531)	(104,197,096)	(251,048)	(104,448,144)	(251,071)	(104,699,215)
System	108RP	OTHER	-	-	-	-	-	-	-	-
Total Renewable Plant			(250,013)	(103,946,565)	(250,531)	(104,197,096)	(251,048)	(104,448,144)	(251,071)	(104,699,215)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Mar 2026	Adjustments	Adjusted Reserve Balance Apr 2026	Adjustments	Adjusted Reserve Balance May 2026	Adjustments	Adjusted Reserve Balance Jun 2026
Other Production Plant:										
Pre-merger Pacific	108OP	SG-W	-	-	-	-	-	-	-	-
Pre-merger Utah	108OP	SG	-	-	-	-	-	-	-	-
Post-merger	108OP	SG	(3,310,592)	(706,882,519)	(3,349,317)	(710,231,836)	(3,389,026)	(713,620,862)	(3,384,316)	(717,005,178)
Oregon	108OP	OR	-	-	-	-	-	-	-	-
Utah	108OP	UT	-	-	-	-	-	-	-	-
System	108OP	SG	(327,148)	(61,711,372)	(327,029)	(62,038,400)	(326,909)	(62,365,309)	(326,868)	(62,692,177)
Total Other Plant			(3,637,740)	(768,593,891)	(3,676,346)	(772,270,237)	(3,715,934)	(775,986,171)	(3,711,184)	(779,697,355)
Transmission Plant:										
California	108TP	CA	-	-	-	-	-	-	-	-
Oregon	108TP	OR	(25,782)	(57,775)	(59,882)	(117,657)	(175,909)	(293,566)	(260,148)	(553,714)
Washington	108TP	WA	-	-	-	-	-	-	-	-
Eastern Wyoming	108TP	WYP	-	-	-	-	-	-	-	-
Western Wyoming	108TP	WYU	-	-	-	-	-	-	-	-
Utah	108TP	UT	-	-	-	-	-	-	-	-
Idaho	108TP	ID	-	-	-	-	-	-	-	-
System	108TP	SG	(496,472)	(365,098,733)	(496,232)	(365,594,965)	(495,992)	(366,090,958)	(495,752)	(366,586,710)
Pre-merger Utah	108TP	SG	(542,419)	(439,225,009)	(542,009)	(439,767,017)	(541,598)	(440,308,615)	(541,188)	(440,849,803)
Post-merger	108TP	SG	(13,872,560)	(1,945,283,550)	(13,894,379)	(1,959,177,928)	(13,929,231)	(1,973,107,160)	(13,986,153)	(1,987,093,313)
System	108TP	OTHER	-	-	-	-	-	-	-	-
Total Transmission Plant			(14,911,451)	(2,749,607,291)	(14,932,620)	(2,764,539,911)	(14,966,822)	(2,779,506,733)	(15,023,093)	(2,794,529,826)
Distribution Plant:										
California	108364	CA	(1,004,838)	(173,729,008)	(1,026,282)	(174,755,290)	(1,057,291)	(175,812,581)	(1,116,561)	(176,929,142)
Oregon	108364	OR	(4,408,259)	(1,281,589,830)	(4,424,343)	(1,286,014,173)	(4,442,174)	(1,290,456,347)	(4,477,575)	(1,294,933,922)
Washington	108364	WA	(1,106,477)	(333,748,477)	(1,111,158)	(334,859,635)	(1,124,150)	(335,983,785)	(1,137,312)	(337,121,097)
Eastern Wyoming	108364	WYP	(1,363,911)	(364,824,540)	(1,370,729)	(366,195,269)	(1,388,004)	(367,583,273)	(1,407,085)	(368,990,358)
Utah	108364	UT	(6,381,427)	(1,328,095,166)	(6,414,843)	(1,334,510,009)	(6,518,673)	(1,341,028,682)	(6,629,039)	(1,347,657,721)
Idaho	108364	ID	(546,458)	(185,523,492)	(550,770)	(186,074,262)	(557,140)	(186,631,402)	(563,900)	(187,195,302)
Western Wyoming	108364	WYU	(321,118)	(77,760,853)	(320,998)	(78,081,851)	(320,877)	(78,402,728)	(320,757)	(78,723,484)
Pre-merger Pacific	108363	SG	-	-	-	-	-	-	-	-
Pre-merger Utah	108363	SG	-	-	-	-	-	-	-	-
System	108363	SNPD	(86,026)	(29,726,770)	(88,285)	(29,815,055)	(90,545)	(29,905,600)	(90,545)	(29,996,145)
System	108363	CN	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)
System	108363	SO	-	-	-	-	-	-	-	-
System	108363	SG	-	-	-	-	-	-	-	-
System	108363	OTHER	-	-	-	-	-	-	-	-
Total Distribution Plant			(15,218,515)	(3,785,800,770)	(15,307,408)	(3,801,108,178)	(15,498,854)	(3,816,607,032)	(15,742,773)	(3,832,349,805)
Energy Storage Plant:										
California	108ES	CA	-	-	-	-	-	-	-	-
Oregon	108ES	OR	-	-	-	-	-	-	-	-
Washington	108ES	WA	-	-	-	-	-	-	-	-
Eastern Wyoming	108ES	WYP	-	-	-	-	-	-	-	-
Utah	108ES	UT	-	-	-	-	-	-	-	-
Idaho	108ES	ID	-	-	-	-	-	-	-	-
Western Wyoming	108ES	WYU	-	-	-	-	-	-	-	-
System	108ES	CN	-	-	-	-	-	-	-	-
System	108ES	SNPD	-	-	-	-	-	-	-	-
System	108ES	SG	-	-	-	-	-	-	-	-
System	108ES	SO	-	-	-	-	-	-	-	-
System	108ES	OTHER	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Mar 2026	Adjustments	Adjusted Reserve Balance Apr 2026	Adjustments	Adjusted Reserve Balance May 2026	Adjustments	Adjusted Reserve Balance Jun 2026
General Plant:										
California	108GP	CA	(14,839)	(6,838,790)	(14,805)	(6,853,595)	(14,775)	(6,868,370)	(14,745)	(6,883,115)
Oregon	108GP	OR	99,254	(67,998,687)	99,880	(67,898,807)	100,417	(67,798,390)	100,932	(67,697,458)
Washington	108GP	WA	(34,185)	(20,493,994)	(34,142)	(20,528,136)	(34,110)	(20,562,246)	(34,035)	(20,596,282)
Eastern Wyoming	108GP	WYP	(146,062)	(25,900,748)	(146,424)	(26,047,172)	(146,790)	(26,193,962)	(146,974)	(26,340,936)
Utah	108GP	UT	(379,353)	(101,149,605)	(379,541)	(101,529,146)	(379,804)	(101,908,949)	(380,187)	(102,289,137)
Idaho	108GP	ID	(80,897)	(18,969,455)	(80,916)	(19,050,371)	(80,935)	(19,131,306)	(80,959)	(19,212,265)
Western Wyoming	108GP	WYU	(34,528)	(7,116,717)	(34,508)	(7,151,225)	(34,488)	(7,185,713)	(34,468)	(7,220,181)
Pre-merger Pacific	108GP	DGP	8,117	(410,187)	8,125	(402,062)	8,133	(393,929)	8,141	(385,788)
Pre-merger Utah	108GP	DGU	25,228	(1,388,967)	25,257	(1,363,710)	25,286	(1,338,424)	25,315	(1,313,110)
Post-merger	108GP	SG	194,489	(58,968,702)	196,111	(58,772,591)	197,733	(58,574,858)	199,355	(58,375,503)
System	108GP	SO	(4,039,170)	(549,278,443)	(4,049,374)	(553,327,816)	(4,062,270)	(557,390,087)	(4,085,573)	(561,475,660)
System	108GP	SG	(172)	(149,092)	(171)	(149,262)	(170)	(149,432)	(169)	(149,601)
System	108GP	SG	-	-	-	-	-	-	-	-
System	108GP	SNPD	-	-	-	-	-	-	-	-
Customer Service	108GP	CN	(505,744)	(214,343,322)	(505,553)	(214,848,875)	(505,363)	(215,354,238)	(505,173)	(215,859,411)
Fuel Related	108GP	SE	3,306	(1,570,498)	3,347	(1,567,150)	3,388	(1,563,762)	3,429	(1,560,332)
Total General Plant			(4,904,556)	(1,074,577,204)	(4,912,715)	(1,079,489,919)	(4,923,748)	(1,084,413,666)	(4,945,112)	(1,089,358,778)
Mining Plant:										
Coal Mine	108MP	SE	-	-	-	-	-	-	-	-
Total Mining Plant			-	-	-	-	-	-	-	-
Total Depreciation Reserve			(86,086,402)	(15,248,009,979)	(86,319,136)	(15,334,329,115)	(86,808,858)	(15,421,137,973)	(87,335,829)	(15,508,473,802)
AMORTIZATION RESERVE										
Intangible Plant:										
California	111IP	CA	147	1,324	147	1,471	147	1,618	147	1,765
Customer Service	111IP	CN	154,776	1,392,988	154,776	1,547,765	154,776	1,702,541	154,776	1,857,318
Pre-merger Pacific	111IP	DGP	-	-	-	-	-	-	-	-
Idaho	111IP	ID	243	(997,817)	243	(997,574)	243	(997,332)	243	(997,089)
Oregon	111IP	OR	(512)	(161,721)	(512)	(162,233)	(511)	(162,744)	(511)	(163,256)
Fuel Related	111IP	SE	-	-	-	-	-	-	-	-
Post-merger	111IP	SG	(151,741)	(84,799,125)	(151,003)	(84,950,128)	(150,266)	(85,100,394)	(149,528)	(85,249,922)
Hydro Relicensing	111IP	SG-P	(223,581)	(53,234,969)	(223,581)	(53,458,550)	(223,581)	(53,682,132)	(223,581)	(53,905,713)
Hydro Relicensing	111IP	SG-U	(5,713)	(7,014,483)	(5,682)	(7,020,165)	(5,651)	(7,025,816)	(5,620)	(7,031,436)
Pre-merger Utah	111IP	DGU	1,055	(437,602)	1,060	(436,542)	1,064	(435,478)	1,069	(434,409)
General Office	111IP	SO	677,200	6,094,796	677,200	6,771,996	677,200	7,449,195	677,200	8,126,395
Utah	111IP	UT	(7,448)	(463,822)	(7,447)	(471,269)	(7,447)	(478,716)	(7,446)	(486,162)
Washington	111IP	WA	252	2,268	252	2,520	252	2,772	252	3,024
Eastern Wyoming	111IP	WYP	1,825	(391,974)	1,831	(390,143)	1,838	(388,305)	1,844	(386,461)
Western Wyoming	111IP	WYU	-	-	-	-	-	-	-	-
Total Intangible Plant			446,503	(140,010,138)	447,284	(139,562,854)	448,064	(139,114,790)	448,844	(138,665,947)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Mar 2026	Adjustments	Adjusted Reserve Balance Apr 2026	Adjustments	Adjusted Reserve Balance May 2026	Adjustments	Adjusted Reserve Balance Jun 2026
Hydro Production Plant:										
Pre-merger Pacific	111HP	DGP	-	-	-	-	-	-	-	-
Pre-merger Utah	111HP	DGU	-	-	-	-	-	-	-	-
Post-merger	111HP	SG	-	-	-	-	-	-	-	-
Post-merger Pacific	111HP	SG-P	(26,228)	(4,629,835)	(26,228)	(4,656,063)	(26,228)	(4,682,291)	(26,228)	(4,708,519)
Post-merger Utah	111HP	SG-U	-	-	-	-	-	-	-	-
Total Hydro Plant			(26,228)	(4,629,835)	(26,228)	(4,656,063)	(26,228)	(4,682,291)	(26,228)	(4,708,519)
Solar Production Plant:										
Oregon	111XP	OR	-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Utah	111XP	UT	-	-	-	-	-	-	-	-
Post-merger	111XP	SG	-	-	-	-	-	-	-	-
System	111XP	OTHER	-	-	-	-	-	-	-	-
Total Solar Plant			-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Wind Production Plant:										
Oregon	111WP	OR	-	-	-	-	-	-	-	-
Utah	111WP	UT	-	-	-	-	-	-	-	-
Post-merger	111WP	SG	-	-	-	-	-	-	-	-
System	111WP	OTHER	-	-	-	-	-	-	-	-
Total Wind Plant			-	-	-	-	-	-	-	-
Renewable Production Plant:										
Oregon	111RP	OR	-	-	-	-	-	-	-	-
Utah	111RP	UT	-	-	-	-	-	-	-	-
Post-merger	111RP	SG	-	-	-	-	-	-	-	-
System	111RP	OTHER	-	-	-	-	-	-	-	-
Total Renewable Plant			-	-	-	-	-	-	-	-
Other Production Plant:										
Oregon	111OP	OR	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-
General Plant:										
California	111GP	CA	-	(512,304)	-	(512,304)	-	(512,304)	-	(512,304)
General Office	111GP	CN	-	-	-	-	-	-	-	-
Idaho	111GP	ID	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)
Oregon	111GP	OR	(6,282)	(5,309,601)	(6,282)	(5,315,883)	(6,282)	(5,322,164)	(6,282)	(5,328,446)
General Office	111GP	SO	(2,848)	(1,900,950)	(2,848)	(1,903,798)	(2,848)	(1,906,646)	(2,848)	(1,909,495)
Utah	111GP	UT	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)
Washington	111GP	WA	(8,458)	(2,340,853)	(8,458)	(2,349,311)	(8,458)	(2,357,769)	(8,458)	(2,366,227)
Eastern Wyoming	111GP	WYP	(289)	(4,740,845)	(289)	(4,741,134)	(289)	(4,741,422)	(289)	(4,741,711)
Western Wyoming	111GP	WYU	-	-	-	-	-	-	-	-
Total General Plant			(17,877)	(15,171,450)	(17,877)	(15,189,327)	(17,877)	(15,207,204)	(17,877)	(15,225,081)
Total Amortization Reserve			402,399	(160,090,842)	403,179	(159,687,664)	403,959	(159,283,704)	404,739	(158,878,965)
Total Depreciation & Amortization Reserve			(85,684,004)	(15,408,100,822)	(85,915,957)	(15,494,016,778)	(86,404,899)	(15,580,421,678)	(86,931,090)	(15,667,352,767)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Jul 2026	Adjustments	Adjusted Reserve Balance Aug 2026	Adjustments	Adjusted Reserve Balance Sep 2026	Adjustments	Adjusted Reserve Balance Oct 2026
DEPRECIATION RESERVE										
Steam Production Plant:										
Pre-merger Pacific	108SP	SG	(4,040,123)	(922,570,661)	(4,039,346)	(926,610,007)	(4,038,569)	(930,648,576)	(4,037,791)	(934,686,367)
Pre-merger Utah	108SP	SG	(3,929,536)	(842,639,388)	(3,928,163)	(846,567,552)	(3,926,791)	(850,494,342)	(3,925,418)	(854,419,760)
Post-merger	108SP	SG	(23,778,692)	(4,212,072,628)	(23,782,430)	(4,235,855,058)	(23,771,444)	(4,259,626,502)	(23,775,720)	(4,283,402,222)
Oregon	108SP	OR	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)
Washington	108SP	WA	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)
California	108SP	CA	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)
Utah	108SP	UT	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)
Idaho	108SP	ID	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)
Eastern Wyoming	108SP	WYP	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)
Western Wyoming	108SP	WYU	-	-	-	-	-	-	-	-
Post-merger	108SP	OTHER	-	-	-	-	-	-	-	-
Total Steam Plant			(31,748,352)	(6,103,987,268)	(31,749,939)	(6,135,737,207)	(31,736,803)	(6,167,474,011)	(31,738,929)	(6,199,212,940)
Hydro Production Plant:										
Pre-merger Pacific	108HP	SG	(304,306)	(142,414,672)	(304,249)	(142,718,921)	(304,192)	(143,023,113)	(304,135)	(143,327,247)
Pre-merger Utah	108HP	SG	(85,300)	(35,250,779)	(85,249)	(35,336,028)	(85,198)	(35,421,226)	(85,148)	(35,506,374)
Post-merger	108HP	SG	(48,910)	(7,834,213)	(48,910)	(7,883,123)	(48,910)	(7,932,033)	(48,910)	(7,980,943)
Post-merger	108HP	SG-P	(1,857,267)	(253,483,361)	(1,859,025)	(255,342,386)	(1,861,770)	(257,204,156)	(1,869,481)	(259,073,637)
Post-merger	108HP	SG-U	(601,785)	(99,074,583)	(601,427)	(99,676,010)	(601,068)	(100,277,078)	(618,659)	(100,895,737)
Total Hydro Plant			(2,897,568)	(538,057,608)	(2,898,859)	(540,956,467)	(2,901,138)	(543,857,605)	(2,926,332)	(546,783,937)
Solar Production Plant:										
Oregon	108XP	OR	(9,767)	(137,408)	(9,767)	(147,175)	(9,767)	(156,942)	(9,767)	(166,710)
Utah	108XP	UT	(1,996)	(110,811)	(1,996)	(112,807)	(1,996)	(114,802)	(1,995)	(116,797)
Post-merger	108XP	SG	-	(67,257)	-	(67,257)	-	(67,257)	-	(67,257)
System	108XP	OTHER	-	-	-	-	-	-	-	-
Total Solar Plant			(11,764)	(315,475)	(11,763)	(327,239)	(11,763)	(339,001)	(11,762)	(350,764)
Wind Production Plant:										
Oregon	108WP	OR	-	-	-	-	-	-	-	-
Utah	108WP	UT	-	-	-	-	-	-	-	-
Post-merger	108WP	SG	(12,820,613)	(312,403,054)	(12,820,255)	(325,223,310)	(12,824,383)	(338,047,692)	(12,828,510)	(350,876,202)
System	108WP	OTHER	-	-	-	-	-	-	-	-
Total Wind Plant			(12,820,613)	(312,403,054)	(12,820,255)	(325,223,310)	(12,824,383)	(338,047,692)	(12,828,510)	(350,876,202)
Renewable Production Plant:										
Oregon	108RP	OR	-	-	-	-	-	-	-	-
Utah	108RP	UT	-	-	-	-	-	-	-	-
Post-merger	108RP	SG	(251,093)	(104,950,308)	(251,116)	(105,201,424)	(251,138)	(105,452,562)	(251,160)	(105,703,722)
System	108RP	OTHER	-	-	-	-	-	-	-	-
Total Renewable Plant			(251,093)	(104,950,308)	(251,116)	(105,201,424)	(251,138)	(105,452,562)	(251,160)	(105,703,722)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Jul 2026	Adjustments	Adjusted Reserve Balance Aug 2026	Adjustments	Adjusted Reserve Balance Sep 2026	Adjustments	Adjusted Reserve Balance Oct 2026
Other Production Plant:										
Pre-merger Pacific	108OP	SG-W	-	-	-	-	-	-	-	-
Pre-merger Utah	108OP	SG	-	-	-	-	-	-	-	-
Post-merger	108OP	SG	(3,378,858)	(720,384,036)	(3,372,246)	(723,756,282)	(3,365,399)	(727,121,681)	(3,358,680)	(730,480,362)
Oregon	108OP	OR	-	-	-	-	-	-	-	-
Utah	108OP	UT	-	-	-	-	-	-	-	-
System	108OP	SG	(326,827)	(63,019,004)	(326,707)	(63,345,712)	(326,588)	(63,672,300)	(326,468)	(63,998,768)
Total Other Plant			(3,705,685)	(783,403,040)	(3,698,954)	(787,101,994)	(3,691,987)	(790,793,981)	(3,685,149)	(794,479,130)
Transmission Plant:										
California	108TP	CA	-	-	-	-	-	-	-	-
Oregon	108TP	OR	(262,570)	(816,284)	(269,488)	(1,085,773)	(276,329)	(1,362,101)	(280,164)	(1,642,266)
Washington	108TP	WA	-	-	-	-	-	-	-	-
Eastern Wyoming	108TP	WYP	-	-	-	-	-	-	-	-
Western Wyoming	108TP	WYU	-	-	-	-	-	-	-	-
Utah	108TP	UT	-	-	-	-	-	-	-	-
Idaho	108TP	ID	-	-	-	-	-	-	-	-
System	108TP	SG	(495,512)	(367,082,222)	(495,272)	(367,577,494)	(495,032)	(368,072,527)	(494,792)	(368,567,319)
Pre-merger Utah	108TP	SG	(540,777)	(441,390,580)	(540,367)	(441,930,947)	(539,956)	(442,470,903)	(539,546)	(443,010,448)
Post-merger	108TP	SG	(14,035,762)	(2,001,129,075)	(14,110,286)	(2,015,239,361)	(14,201,190)	(2,029,440,551)	(14,275,396)	(2,043,715,948)
System	108TP	OTHER	-	-	-	-	-	-	-	-
Total Transmission Plant			(15,072,052)	(2,809,601,877)	(15,145,925)	(2,824,747,802)	(15,236,178)	(2,839,983,980)	(15,309,734)	(2,855,293,715)
Distribution Plant:										
California	108364	CA	(1,172,501)	(178,101,643)	(1,198,720)	(179,300,363)	(1,203,224)	(180,503,587)	(1,215,218)	(181,718,805)
Oregon	108364	OR	(4,514,093)	(1,299,448,015)	(4,532,887)	(1,303,980,902)	(4,556,929)	(1,308,537,831)	(4,586,166)	(1,313,123,997)
Washington	108364	WA	(1,143,063)	(338,264,160)	(1,148,524)	(339,412,683)	(1,152,496)	(340,565,180)	(1,155,579)	(341,720,759)
Eastern Wyoming	108364	WYP	(1,417,948)	(370,408,306)	(1,429,962)	(371,838,268)	(1,442,630)	(373,280,898)	(1,453,696)	(374,734,594)
Utah	108364	UT	(6,689,721)	(1,354,347,442)	(6,752,929)	(1,361,100,371)	(6,802,967)	(1,367,903,338)	(6,865,252)	(1,374,768,591)
Idaho	108364	ID	(568,741)	(187,764,043)	(573,812)	(188,337,856)	(579,741)	(188,917,596)	(585,187)	(189,502,783)
Western Wyoming	108364	WYU	(320,636)	(79,044,120)	(320,515)	(79,364,635)	(320,395)	(79,685,030)	(320,274)	(80,005,304)
Pre-merger Pacific	108363	SG	-	-	-	-	-	-	-	-
Pre-merger Utah	108363	SG	-	-	-	-	-	-	-	-
System	108363	SNPD	(90,545)	(30,086,690)	(90,545)	(30,177,235)	(90,545)	(30,267,779)	(90,545)	(30,358,324)
System	108363	CN	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)
System	108363	SO	-	-	-	-	-	-	-	-
System	108363	SG	-	-	-	-	-	-	-	-
System	108363	OTHER	-	-	-	-	-	-	-	-
Total Distribution Plant			(15,917,248)	(3,848,267,053)	(16,047,895)	(3,864,314,948)	(16,148,926)	(3,880,463,874)	(16,271,917)	(3,896,735,791)
Energy Storage Plant:										
California	108ES	CA	-	-	-	-	-	-	-	-
Oregon	108ES	OR	-	-	-	-	-	-	-	-
Washington	108ES	WA	-	-	-	-	-	-	-	-
Eastern Wyoming	108ES	WYP	-	-	-	-	-	-	-	-
Utah	108ES	UT	-	-	-	-	-	-	-	-
Idaho	108ES	ID	-	-	-	-	-	-	-	-
Western Wyoming	108ES	WYU	-	-	-	-	-	-	-	-
System	108ES	CN	-	-	-	-	-	-	-	-
System	108ES	SNPD	-	-	-	-	-	-	-	-
System	108ES	SG	-	-	-	-	-	-	-	-
System	108ES	SO	-	-	-	-	-	-	-	-
System	108ES	OTHER	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Jul 2026	Adjustments	Adjusted Reserve Balance Aug 2026	Adjustments	Adjusted Reserve Balance Sep 2026	Adjustments	Adjusted Reserve Balance Oct 2026
General Plant:										
California	108GP	CA	(14,722)	(6,897,837)	(14,702)	(6,912,539)	(14,677)	(6,927,216)	(14,658)	(6,941,874)
Oregon	108GP	OR	101,315	(67,596,142)	101,628	(67,494,515)	102,052	(67,392,462)	102,329	(67,290,133)
Washington	108GP	WA	(33,975)	(20,630,257)	(33,923)	(20,664,180)	(33,859)	(20,698,039)	(33,811)	(20,731,850)
Eastern Wyoming	108GP	WYP	(147,155)	(26,488,091)	(147,335)	(26,635,426)	(147,519)	(26,782,945)	(147,702)	(26,930,646)
Utah	108GP	UT	(380,631)	(102,669,768)	(381,132)	(103,050,900)	(381,644)	(103,432,544)	(382,097)	(103,814,641)
Idaho	108GP	ID	(80,983)	(19,293,247)	(81,006)	(19,374,253)	(81,030)	(19,455,283)	(81,054)	(19,536,337)
Western Wyoming	108GP	WYU	(34,448)	(7,254,630)	(34,428)	(7,289,058)	(34,408)	(7,323,466)	(34,388)	(7,357,854)
Pre-merger Pacific	108GP	DGP	8,149	(377,638)	8,158	(369,481)	8,166	(361,315)	8,174	(353,141)
Pre-merger Utah	108GP	DGU	25,343	(1,287,766)	25,372	(1,262,394)	25,401	(1,236,993)	25,430	(1,211,563)
Post-merger	108GP	SG	200,977	(58,174,526)	202,599	(57,971,927)	204,221	(57,767,706)	205,843	(57,561,863)
System	108GP	SO	(4,111,050)	(565,586,710)	(4,125,889)	(569,712,599)	(4,137,194)	(573,849,793)	(4,149,897)	(577,999,690)
System	108GP	SG	(168)	(149,769)	(167)	(149,936)	(166)	(150,102)	(165)	(150,268)
System	108GP	SG	-	-	-	-	-	-	-	-
System	108GP	SNPD	-	-	-	-	-	-	-	-
Customer Service	108GP	CN	(504,983)	(216,364,394)	(504,793)	(216,869,187)	(504,602)	(217,373,789)	(504,412)	(217,878,201)
Fuel Related	108GP	SE	3,470	(1,556,862)	3,511	(1,553,351)	3,552	(1,549,799)	3,593	(1,546,206)
Total General Plant			(4,968,860)	(1,094,327,638)	(4,982,107)	(1,099,309,746)	(4,991,706)	(1,104,301,452)	(5,002,815)	(1,109,304,267)
Mining Plant:										
Coal Mine	108MP	SE	-	-	-	-	-	-	-	-
Total Mining Plant			-	-	-	-	-	-	-	-
Total Depreciation Reserve			(87,655,805)	(15,596,129,607)	(87,876,302)	(15,684,005,909)	(88,070,350)	(15,772,076,259)	(88,306,473)	(15,860,382,733)
AMORTIZATION RESERVE										
Intangible Plant:										
California	111IP	CA	147	1,912	147	2,059	147	2,207	147	2,354
Customer Service	111IP	CN	154,776	2,012,094	154,776	2,166,871	154,776	2,321,647	154,776	2,476,423
Pre-merger Pacific	111IP	DGP	-	-	-	-	-	-	-	-
Idaho	111IP	ID	243	(996,847)	243	(996,604)	243	(996,361)	243	(996,119)
Oregon	111IP	OR	(511)	(163,767)	(511)	(164,279)	(511)	(164,790)	(511)	(165,301)
Fuel Related	111IP	SE	-	-	-	-	-	-	-	-
Post-merger	111IP	SG	(148,790)	(85,398,711)	(148,052)	(85,546,763)	(147,314)	(85,694,077)	(146,576)	(85,840,653)
Hydro Relicensing	111IP	SG-P	(223,581)	(54,129,294)	(223,581)	(54,352,875)	(223,581)	(54,576,457)	(223,581)	(54,800,038)
Hydro Relicensing	111IP	SG-U	(5,589)	(7,037,025)	(5,558)	(7,042,583)	(5,527)	(7,048,109)	(5,496)	(7,053,605)
Pre-merger Utah	111IP	DGU	1,073	(433,335)	1,078	(432,258)	1,082	(431,175)	1,087	(430,089)
General Office	111IP	SO	677,200	8,803,594	677,200	9,480,794	677,200	10,157,993	677,200	10,835,193
Utah	111IP	UT	(7,446)	(493,608)	(7,445)	(501,053)	(7,445)	(508,498)	(7,445)	(515,943)
Washington	111IP	WA	252	3,276	252	3,528	252	3,779	252	4,031
Eastern Wyoming	111IP	WYP	1,850	(384,611)	1,856	(382,755)	1,862	(380,893)	1,869	(379,024)
Western Wyoming	111IP	WYU	-	-	-	-	-	-	-	-
Total Intangible Plant			449,624	(138,216,323)	450,404	(137,765,918)	451,184	(137,314,734)	451,964	(136,862,770)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Jul 2026	Adjustments	Adjusted Reserve Balance Aug 2026	Adjustments	Adjusted Reserve Balance Sep 2026	Adjustments	Adjusted Reserve Balance Oct 2026
Hydro Production Plant:										
Pre-merger Pacific	111HP	DGP	-	-	-	-	-	-	-	-
Pre-merger Utah	111HP	DGU	-	-	-	-	-	-	-	-
Post-merger	111HP	SG	-	-	-	-	-	-	-	-
Post-merger Pacific	111HP	SG-P	(26,228)	(4,734,746)	(26,228)	(4,760,974)	(26,228)	(4,787,202)	(26,228)	(4,813,429)
Post-merger Utah	111HP	SG-U	-	-	-	-	-	-	-	-
Total Hydro Plant			(26,228)	(4,734,746)	(26,228)	(4,760,974)	(26,228)	(4,787,202)	(26,228)	(4,813,429)
Solar Production Plant:										
Oregon	111XP	OR	-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Utah	111XP	UT	-	-	-	-	-	-	-	-
Post-merger	111XP	SG	-	-	-	-	-	-	-	-
System	111XP	OTHER	-	-	-	-	-	-	-	-
Total Solar Plant			-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Wind Production Plant:										
Oregon	111WP	OR	-	-	-	-	-	-	-	-
Utah	111WP	UT	-	-	-	-	-	-	-	-
Post-merger	111WP	SG	-	-	-	-	-	-	-	-
System	111WP	OTHER	-	-	-	-	-	-	-	-
Total Wind Plant			-	-	-	-	-	-	-	-
Renewable Production Plant:										
Oregon	111RP	OR	-	-	-	-	-	-	-	-
Utah	111RP	UT	-	-	-	-	-	-	-	-
Post-merger	111RP	SG	-	-	-	-	-	-	-	-
System	111RP	OTHER	-	-	-	-	-	-	-	-
Total Renewable Plant			-	-	-	-	-	-	-	-
Other Production Plant:										
Oregon	111OP	OR	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-
General Plant:										
California	111GP	CA	-	(512,304)	-	(512,304)	-	(512,304)	-	(512,304)
General Office	111GP	CN	-	-	-	-	-	-	-	-
Idaho	111GP	ID	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)
Oregon	111GP	OR	(6,282)	(5,334,728)	(6,282)	(5,341,010)	(6,282)	(5,347,292)	(6,282)	(5,353,574)
General Office	111GP	SO	(2,848)	(1,912,343)	(2,848)	(1,915,191)	(2,848)	(1,918,040)	(2,848)	(1,920,888)
Utah	111GP	UT	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)
Washington	111GP	WA	(8,458)	(2,374,685)	(8,458)	(2,383,143)	(8,458)	(2,391,601)	(8,458)	(2,400,060)
Eastern Wyoming	111GP	WYP	(289)	(4,741,999)	(289)	(4,742,288)	(289)	(4,742,577)	(289)	(4,742,865)
Western Wyoming	111GP	WYU	-	-	-	-	-	-	-	-
Total General Plant			(17,877)	(15,242,958)	(17,877)	(15,260,834)	(17,877)	(15,278,711)	(17,877)	(15,296,588)
Total Amortization Reserve			405,519	(158,473,446)	406,300	(158,067,146)	407,080	(157,660,066)	407,860	(157,252,206)
Total Depreciation & Amortization Reserve			(87,250,285)	(15,754,603,052)	(87,470,003)	(15,842,073,055)	(87,663,270)	(15,929,736,326)	(87,898,613)	(16,017,634,939)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Nov 2026	Adjustments	Adjusted Reserve Balance Dec 2026	Adjustments	Adjusted Reserve Balance Jan 2027	Adjustments	Adjusted Reserve Balance Feb 2027
DEPRECIATION RESERVE										
Steam Production Plant:										
Pre-merger Pacific	108SP	SG	(4,037,014)	(938,723,381)	(4,036,237)	(942,759,618)	(4,035,459)	(946,795,077)	(4,034,682)	(950,829,758)
Pre-merger Utah	108SP	SG	(3,924,045)	(858,343,806)	(3,922,673)	(862,266,478)	(3,921,300)	(866,187,778)	(3,919,928)	(870,107,706)
Post-merger	108SP	SG	(23,790,430)	(4,307,192,652)	(23,893,145)	(4,331,085,796)	(23,983,292)	(4,355,069,088)	(23,971,279)	(4,379,040,367)
Oregon	108SP	OR	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)
Washington	108SP	WA	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)
California	108SP	CA	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)
Utah	108SP	UT	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)
Idaho	108SP	ID	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)
Eastern Wyoming	108SP	WYP	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)
Western Wyoming	108SP	WYU	-	-	-	-	-	-	-	-
Post-merger	108SP	OTHER	-	-	-	-	-	-	-	-
Total Steam Plant			(31,751,489)	(6,230,964,429)	(31,852,054)	(6,262,816,483)	(31,940,051)	(6,294,756,534)	(31,925,888)	(6,326,682,423)
Hydro Production Plant:										
Pre-merger Pacific	108HP	SG	(304,078)	(143,631,325)	(304,021)	(143,935,346)	(303,964)	(144,239,310)	(303,907)	(144,543,217)
Pre-merger Utah	108HP	SG	(85,097)	(35,591,470)	(85,046)	(35,676,516)	(84,995)	(35,761,511)	(84,944)	(35,846,456)
Post-merger	108HP	SG	(48,910)	(8,029,853)	(48,910)	(8,078,762)	(48,910)	(8,127,672)	(48,910)	(8,176,582)
Post-merger	108HP	SG-P	(1,904,635)	(260,978,272)	(2,044,774)	(263,023,046)	(2,260,710)	(265,283,756)	(2,260,174)	(267,543,930)
Post-merger	108HP	SG-U	(639,393)	(101,535,129)	(666,816)	(102,201,945)	(691,097)	(102,893,042)	(690,739)	(103,583,781)
Total Hydro Plant			(2,982,113)	(549,766,050)	(3,149,567)	(552,915,616)	(3,389,676)	(556,305,292)	(3,388,674)	(559,693,966)
Solar Production Plant:										
Oregon	108XP	OR	(9,767)	(176,477)	(10,170)	(186,647)	(10,573)	(197,221)	(10,573)	(207,794)
Utah	108XP	UT	(1,995)	(118,792)	(1,994)	(120,786)	(1,994)	(122,780)	(1,993)	(124,773)
Post-merger	108XP	SG	-	(67,257)	-	(67,257)	-	(67,257)	-	(67,257)
System	108XP	OTHER	-	-	-	-	-	-	-	-
Total Solar Plant			(11,762)	(362,526)	(12,164)	(374,690)	(12,567)	(387,257)	(12,567)	(399,824)
Wind Production Plant:										
Oregon	108WP	OR	-	-	-	-	-	-	-	-
Utah	108WP	UT	-	-	-	-	-	-	-	-
Post-merger	108WP	SG	(12,831,551)	(363,707,753)	(12,864,022)	(376,571,774)	(12,893,094)	(389,464,869)	(12,892,737)	(402,357,605)
System	108WP	OTHER	-	-	-	-	-	-	-	-
Total Wind Plant			(12,831,551)	(363,707,753)	(12,864,022)	(376,571,774)	(12,893,094)	(389,464,869)	(12,892,737)	(402,357,605)
Renewable Production Plant:										
Oregon	108RP	OR	-	-	-	-	-	-	-	-
Utah	108RP	UT	-	-	-	-	-	-	-	-
Post-merger	108RP	SG	(251,183)	(105,954,905)	(251,205)	(106,206,110)	(251,228)	(106,457,338)	(251,251)	(106,708,589)
System	108RP	OTHER	-	-	-	-	-	-	-	-
Total Renewable Plant			(251,183)	(105,954,905)	(251,205)	(106,206,110)	(251,228)	(106,457,338)	(251,251)	(106,708,589)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Nov 2026	Adjustments	Adjusted Reserve Balance Dec 2026	Adjustments	Adjusted Reserve Balance Jan 2027	Adjustments	Adjusted Reserve Balance Feb 2027
Other Production Plant:										
Pre-merger Pacific	108OP	SG-W	-	-	-	-	-	-	-	-
Pre-merger Utah	108OP	SG	-	-	-	-	-	-	-	-
Post-merger	108OP	SG	(3,362,461)	(733,842,823)	(3,447,037)	(737,289,860)	(3,521,117)	(740,810,977)	(3,514,277)	(744,325,254)
Oregon	108OP	OR	-	-	-	-	-	-	-	-
Utah	108OP	UT	-	-	-	-	-	-	-	-
System	108OP	SG	(326,348)	(64,325,116)	(326,229)	(64,651,345)	(326,109)	(64,977,454)	(325,989)	(65,303,443)
Total Other Plant			(3,688,810)	(798,167,939)	(3,773,266)	(801,941,205)	(3,847,226)	(805,788,431)	(3,840,266)	(809,628,697)
Transmission Plant:										
California	108TP	CA	-	-	-	-	-	-	-	-
Oregon	108TP	OR	(284,021)	(1,926,287)	(287,887)	(2,214,173)	(289,892)	(2,504,065)	(290,054)	(2,794,119)
Washington	108TP	WA	-	-	-	-	-	-	-	-
Eastern Wyoming	108TP	WYP	-	-	-	-	-	-	-	-
Western Wyoming	108TP	WYU	-	-	-	-	-	-	-	-
Utah	108TP	UT	-	-	-	-	-	-	-	-
Idaho	108TP	ID	-	-	-	-	-	-	-	-
System	108TP	SG	(494,552)	(369,061,871)	(494,312)	(369,556,183)	(494,072)	(370,050,256)	(493,832)	(370,544,088)
Pre-merger Utah	108TP	SG	(539,135)	(443,549,583)	(538,724)	(444,088,308)	(538,314)	(444,626,621)	(537,903)	(445,164,525)
Post-merger	108TP	SG	(14,355,371)	(2,058,071,319)	(14,461,558)	(2,072,532,877)	(14,533,922)	(2,087,066,798)	(14,591,735)	(2,101,658,533)
System	108TP	OTHER	-	-	-	-	-	-	-	-
Total Transmission Plant			(15,389,058)	(2,870,682,773)	(15,494,595)	(2,886,177,368)	(15,566,308)	(2,901,743,675)	(15,623,470)	(2,917,367,146)
Distribution Plant:										
California	108364	CA	(1,233,367)	(182,952,172)	(1,278,804)	(184,230,976)	(1,319,708)	(185,550,684)	(1,328,792)	(186,879,476)
Oregon	108364	OR	(4,618,244)	(1,317,742,241)	(4,644,908)	(1,322,387,149)	(4,656,034)	(1,327,043,183)	(4,661,665)	(1,331,704,849)
Washington	108364	WA	(1,158,163)	(342,878,922)	(1,160,972)	(344,039,894)	(1,163,519)	(345,203,414)	(1,165,181)	(346,368,595)
Eastern Wyoming	108364	WYP	(1,488,815)	(376,223,409)	(1,525,958)	(377,749,366)	(1,535,419)	(379,284,786)	(1,540,581)	(380,825,367)
Utah	108364	UT	(6,922,184)	(1,381,690,775)	(7,016,651)	(1,388,707,425)	(7,104,109)	(1,395,811,534)	(7,130,310)	(1,402,941,844)
Idaho	108364	ID	(589,740)	(190,092,523)	(599,624)	(190,692,147)	(608,975)	(191,301,122)	(612,657)	(191,913,779)
Western Wyoming	108364	WYU	(320,154)	(80,325,458)	(320,033)	(80,645,491)	(319,912)	(80,965,403)	(319,792)	(81,285,195)
Pre-merger Pacific	108363	SG	-	-	-	-	-	-	-	-
Pre-merger Utah	108363	SG	-	-	-	-	-	-	-	-
System	108363	SNPD	(90,545)	(30,448,869)	(90,545)	(30,539,414)	(90,545)	(30,629,959)	(90,545)	(30,720,504)
System	108363	CN	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)
System	108363	SO	-	-	-	-	-	-	-	-
System	108363	SG	-	-	-	-	-	-	-	-
System	108363	OTHER	-	-	-	-	-	-	-	-
Total Distribution Plant			(16,421,212)	(3,913,157,003)	(16,637,494)	(3,929,794,497)	(16,798,221)	(3,946,592,718)	(16,849,524)	(3,963,442,243)
Energy Storage Plant:										
California	108ES	CA	-	-	-	-	-	-	-	-
Oregon	108ES	OR	-	-	-	-	-	-	-	-
Washington	108ES	WA	-	-	-	-	-	-	-	-
Eastern Wyoming	108ES	WYP	-	-	-	-	-	-	-	-
Utah	108ES	UT	-	-	-	-	-	-	-	-
Idaho	108ES	ID	-	-	-	-	-	-	-	-
Western Wyoming	108ES	WYU	-	-	-	-	-	-	-	-
System	108ES	CN	-	-	-	-	-	-	-	-
System	108ES	SNPD	-	-	-	-	-	-	-	-
System	108ES	SG	-	-	-	-	-	-	-	-
System	108ES	SO	-	-	-	-	-	-	-	-
System	108ES	OTHER	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Nov 2026	Adjustments	Adjusted Reserve Balance Dec 2026	Adjustments	Adjusted Reserve Balance Jan 2027	Adjustments	Adjusted Reserve Balance Feb 2027
General Plant:										
California	108GP	CA	(14,645)	(6,956,519)	(14,636)	(6,971,155)	(14,615)	(6,985,770)	(14,577)	(7,000,347)
Oregon	108GP	OR	102,478	(67,187,655)	102,553	(67,085,102)	102,888	(66,982,215)	103,571	(66,878,644)
Washington	108GP	WA	(33,778)	(20,765,628)	(33,753)	(20,799,381)	(33,698)	(20,833,080)	(33,603)	(20,866,682)
Eastern Wyoming	108GP	WYP	(147,899)	(27,078,545)	(148,583)	(27,227,128)	(149,224)	(27,376,352)	(149,331)	(27,525,683)
Utah	108GP	UT	(382,606)	(104,197,246)	(383,114)	(104,580,360)	(383,380)	(104,963,740)	(383,431)	(105,347,170)
Idaho	108GP	ID	(81,082)	(19,617,419)	(81,117)	(19,698,536)	(81,149)	(19,779,686)	(81,171)	(19,860,856)
Western Wyoming	108GP	WYU	(34,368)	(7,392,222)	(34,348)	(7,426,570)	(34,328)	(7,460,898)	(34,308)	(7,495,206)
Pre-merger Pacific	108GP	DGP	8,182	(344,959)	8,190	(336,769)	8,199	(328,570)	8,207	(320,364)
Pre-merger Utah	108GP	DGU	25,459	(1,186,104)	25,488	(1,160,617)	25,516	(1,135,100)	25,545	(1,109,555)
Post-merger	108GP	SG	207,465	(57,354,398)	209,087	(57,145,311)	210,709	(56,934,602)	212,331	(56,722,271)
System	108GP	SO	(4,165,839)	(582,165,530)	(4,280,996)	(586,446,526)	(4,388,366)	(590,834,892)	(4,392,706)	(595,227,598)
System	108GP	SG	(164)	(150,432)	(164)	(150,596)	(163)	(150,759)	(162)	(150,920)
System	108GP	SG	-	-	-	-	-	-	-	-
System	108GP	SNPD	-	-	-	-	-	-	-	-
Customer Service	108GP	CN	(504,222)	(218,382,423)	(504,032)	(218,886,455)	(503,842)	(219,390,297)	(503,652)	(219,893,948)
Fuel Related	108GP	SE	3,634	(1,542,571)	3,675	(1,538,896)	3,716	(1,535,180)	3,757	(1,531,423)
Total General Plant			(5,017,387)	(1,114,321,653)	(5,131,749)	(1,119,453,403)	(5,237,737)	(1,124,691,140)	(5,239,528)	(1,129,930,669)
Mining Plant:										
Coal Mine	108MP	SE	-	-	-	-	-	-	-	-
Total Mining Plant			-	-	-	-	-	-	-	-
Total Depreciation Reserve			(88,628,584)	(15,949,011,317)	(89,454,003)	(16,038,465,319)	(90,226,001)	(16,128,691,320)	(90,313,960)	(16,219,005,280)
AMORTIZATION RESERVE										
Intangible Plant:										
California	111IP	CA	147	2,501	147	2,648	147	2,795	147	2,942
Customer Service	111IP	CN	154,776	2,631,200	154,776	2,785,976	154,776	2,940,753	154,776	3,095,529
Pre-merger Pacific	111IP	DGP	-	-	-	-	-	-	-	-
Idaho	111IP	ID	243	(995,876)	243	(995,634)	243	(995,391)	243	(995,149)
Oregon	111IP	OR	(511)	(165,812)	(511)	(166,324)	(511)	(166,835)	(511)	(167,346)
Fuel Related	111IP	SE	-	-	-	-	-	-	-	-
Post-merger	111IP	SG	(145,838)	(85,986,491)	(145,100)	(86,131,592)	(144,362)	(86,275,954)	(143,624)	(86,419,578)
Hydro Relicensing	111IP	SG-P	(223,581)	(55,023,619)	(223,581)	(55,247,200)	(223,581)	(55,470,781)	(223,581)	(55,694,363)
Hydro Relicensing	111IP	SG-U	(5,464)	(7,059,069)	(5,433)	(7,064,502)	(5,402)	(7,069,905)	(5,371)	(7,075,276)
Pre-merger Utah	111IP	DGU	1,091	(428,997)	1,096	(427,902)	1,100	(426,801)	1,105	(425,697)
General Office	111IP	SO	677,200	11,512,392	677,200	12,189,592	677,200	12,866,792	677,200	13,543,991
Utah	111IP	UT	(7,444)	(523,387)	(7,444)	(530,831)	(7,443)	(538,274)	(7,443)	(545,717)
Washington	111IP	WA	252	4,283	252	4,535	252	4,787	252	5,039
Eastern Wyoming	111IP	WYP	1,875	(377,149)	1,881	(375,268)	1,887	(373,381)	1,893	(371,487)
Western Wyoming	111IP	WYU	-	-	-	-	-	-	-	-
Total Intangible Plant			452,745	(136,410,025)	453,525	(135,956,500)	454,305	(135,502,195)	455,085	(135,047,110)

PacifiCorp
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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Nov 2026	Adjustments	Adjusted Reserve Balance Dec 2026	Adjustments	Adjusted Reserve Balance Jan 2027	Adjustments	Adjusted Reserve Balance Feb 2027
Hydro Production Plant:										
Pre-merger Pacific	111HP	DGP	-	-	-	-	-	-	-	-
Pre-merger Utah	111HP	DGU	-	-	-	-	-	-	-	-
Post-merger	111HP	SG	-	-	-	-	-	-	-	-
Post-merger Pacific	111HP	SG-P	(26,228)	(4,839,657)	(26,228)	(4,865,885)	(26,228)	(4,892,113)	(26,228)	(4,918,340)
Post-merger Utah	111HP	SG-U	-	-	-	-	-	-	-	-
Total Hydro Plant			(26,228)	(4,839,657)	(26,228)	(4,865,885)	(26,228)	(4,892,113)	(26,228)	(4,918,340)
Solar Production Plant:										
Oregon	111XP	OR	-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Utah	111XP	UT	-	-	-	-	-	-	-	-
Post-merger	111XP	SG	-	-	-	-	-	-	-	-
System	111XP	OTHER	-	-	-	-	-	-	-	-
Total Solar Plant			-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Wind Production Plant:										
Oregon	111WP	OR	-	-	-	-	-	-	-	-
Utah	111WP	UT	-	-	-	-	-	-	-	-
Post-merger	111WP	SG	-	-	-	-	-	-	-	-
System	111WP	OTHER	-	-	-	-	-	-	-	-
Total Wind Plant			-	-	-	-	-	-	-	-
Renewable Production Plant:										
Oregon	111RP	OR	-	-	-	-	-	-	-	-
Utah	111RP	UT	-	-	-	-	-	-	-	-
Post-merger	111RP	SG	-	-	-	-	-	-	-	-
System	111RP	OTHER	-	-	-	-	-	-	-	-
Total Renewable Plant			-	-	-	-	-	-	-	-
Other Production Plant:										
Oregon	111OP	OR	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-
General Plant:										
California	111GP	CA	-	(512,304)	-	(512,304)	-	(512,304)	-	(512,304)
General Office	111GP	CN	-	-	-	-	-	-	-	-
Idaho	111GP	ID	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)
Oregon	111GP	OR	(6,282)	(5,359,855)	(6,282)	(5,366,137)	(6,282)	(5,372,419)	(6,282)	(5,378,701)
General Office	111GP	SO	(2,848)	(1,923,736)	(2,848)	(1,926,585)	(2,848)	(1,929,433)	(2,848)	(1,932,281)
Utah	111GP	UT	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)
Washington	111GP	WA	(8,458)	(2,408,518)	(8,458)	(2,416,976)	(8,458)	(2,425,434)	(8,458)	(2,433,892)
Eastern Wyoming	111GP	WYP	(289)	(4,743,154)	(289)	(4,743,443)	(289)	(4,743,731)	(289)	(4,744,020)
Western Wyoming	111GP	WYU	-	-	-	-	-	-	-	-
Total General Plant			(17,877)	(15,314,465)	(17,877)	(15,332,342)	(17,877)	(15,350,218)	(17,877)	(15,368,095)
Total Amortization Reserve			408,640	(156,843,566)	409,420	(156,434,146)	410,200	(156,023,946)	410,981	(155,612,965)
Total Depreciation & Amortization Reserve			(88,219,944)	(16,105,854,883)	(89,044,583)	(16,194,899,466)	(89,815,800)	(16,284,715,266)	(89,902,979)	(16,374,618,245)

PacifiCorp
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June 2025 - December 2027 Depreciation & Amortization Reserve

Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Mar 2027	Adjustments	Adjusted Reserve Balance Apr 2027	Adjustments	Adjusted Reserve Balance May 2027	Adjustments	Adjusted Reserve Balance Jun 2027	Adjustments	Adjusted Reserve Balance Jul 2027
DEPRECIATION RESERVE												
Steam Production Plant:												
Pre-merger Pacific	108SP	SG	(4,033,904)	(954,863,663)	(4,214,952)	(959,078,615)	(4,214,952)	(963,293,567)	(4,214,952)	(967,508,519)	(4,214,952)	(971,723,471)
Pre-merger Utah	108SP	SG	(3,918,555)	(874,026,261)	(4,243,848)	(878,270,109)	(4,243,848)	(882,513,957)	(4,243,848)	(886,757,805)	(4,243,848)	(891,001,653)
Post-merger	108SP	SG	(23,959,104)	(4,402,999,471)	(27,822,844)	(4,430,822,316)	(27,822,844)	(4,458,645,160)	(27,822,844)	(4,486,468,004)	(27,822,844)	(4,514,290,849)
Oregon	108SP	OR	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)
Washington	108SP	WA	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)
California	108SP	CA	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)
Utah	108SP	UT	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)
Idaho	108SP	ID	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)
Eastern Wyoming	108SP	WYP	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)
Western Wyoming	108SP	WYU	-	-	-	-	-	-	-	-	-	-
Post-merger	108SP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Steam Plant			(31,911,564)	(6,358,593,986)	(36,281,644)	(6,394,875,630)	(36,281,644)	(6,431,157,275)	(36,281,644)	(6,467,438,919)	(36,281,644)	(6,503,720,563)
Hydro Production Plant:												
Pre-merger Pacific	108HP	SG	(303,850)	(144,847,067)	(333,392)	(145,180,459)	(333,392)	(145,513,852)	(333,392)	(145,847,244)	(333,392)	(146,180,636)
Pre-merger Utah	108HP	SG	(84,893)	(35,931,349)	(104,010)	(36,035,359)	(104,010)	(36,139,368)	(104,010)	(36,243,378)	(104,010)	(36,347,387)
Post-merger	108HP	SG	(48,910)	(8,225,492)	(48,910)	(8,274,402)	(48,910)	(8,323,312)	(48,910)	(8,372,222)	(48,910)	(8,421,132)
Post-merger	108HP	SG-P	(2,259,638)	(269,803,568)	(2,591,611)	(272,395,179)	(2,591,611)	(274,986,791)	(2,591,611)	(277,578,402)	(2,591,611)	(280,170,014)
Post-merger	108HP	SG-U	(691,295)	(104,275,076)	(791,005)	(105,066,081)	(791,005)	(105,857,085)	(791,005)	(106,648,090)	(791,005)	(107,439,095)
Total Hydro Plant			(3,388,586)	(563,082,552)	(3,868,928)	(566,951,480)	(3,868,928)	(570,820,408)	(3,868,928)	(574,689,336)	(3,868,928)	(578,558,264)
Solar Production Plant:												
Oregon	108XP	OR	(10,573)	(218,368)	(10,573)	(228,941)	(10,573)	(239,515)	(10,573)	(250,088)	(10,573)	(260,661)
Utah	108XP	UT	(1,993)	(126,766)	(2,116)	(128,881)	(2,116)	(130,997)	(2,116)	(133,113)	(2,116)	(135,228)
Post-merger	108XP	SG	-	(67,257)	-	(67,257)	-	(67,257)	-	(67,257)	-	(67,257)
System	108XP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Solar Plant			(12,566)	(412,390)	(12,689)	(425,079)	(12,689)	(437,768)	(12,689)	(450,457)	(12,689)	(463,146)
Wind Production Plant:												
Oregon	108WP	OR	-	-	-	-	-	-	-	-	-	-
Utah	108WP	UT	-	-	-	-	-	-	-	-	-	-
Post-merger	108WP	SG	(12,897,629)	(415,255,234)	(12,795,190)	(428,050,424)	(12,795,190)	(440,845,613)	(12,795,190)	(453,640,803)	(12,795,190)	(466,435,993)
System	108WP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Wind Plant			(12,897,629)	(415,255,234)	(12,795,190)	(428,050,424)	(12,795,190)	(440,845,613)	(12,795,190)	(453,640,803)	(12,795,190)	(466,435,993)
Renewable Production Plant:												
Oregon	108RP	OR	-	-	-	-	-	-	-	-	-	-
Utah	108RP	UT	-	-	-	-	-	-	-	-	-	-
Post-merger	108RP	SG	(251,709)	(106,960,298)	(252,156)	(107,212,454)	(252,156)	(107,464,609)	(252,156)	(107,716,765)	(252,156)	(107,968,920)
System	108RP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Renewable Plant			(251,709)	(106,960,298)	(252,156)	(107,212,454)	(252,156)	(107,464,609)	(252,156)	(107,716,765)	(252,156)	(107,968,920)

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June 2025 - December 2027 Depreciation & Amortization Reserve

Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Mar 2027	Adjustments	Adjusted Reserve Balance Apr 2027	Adjustments	Adjusted Reserve Balance May 2027	Adjustments	Adjusted Reserve Balance Jun 2027	Adjustments	Adjusted Reserve Balance Jul 2027
Other Production Plant:												
Pre-merger Pacific	108OP	SG-W	-	-	-	-	-	-	-	-	-	-
Pre-merger Utah	108OP	SG	-	-	-	-	-	-	-	-	-	-
Post-merger	108OP	SG	(3,507,437)	(747,832,691)	(5,933,449)	(753,766,140)	(5,933,449)	(759,699,589)	(5,933,449)	(765,633,039)	(5,933,449)	(771,566,488)
Oregon	108OP	OR	-	-	-	-	-	-	-	-	-	-
Utah	108OP	UT	-	-	-	-	-	-	-	-	-	-
System	108OP	SG	(325,870)	(65,629,312)	(355,540)	(65,984,852)	(355,540)	(66,340,392)	(355,540)	(66,695,931)	(355,540)	(67,051,471)
Total Other Plant			(3,833,306)	(813,462,004)	(6,288,989)	(819,750,992)	(6,288,989)	(826,039,981)	(6,288,989)	(832,328,970)	(6,288,989)	(838,617,959)
Transmission Plant:												
California	108TP	CA	-	-	-	-	-	-	-	-	-	-
Oregon	108TP	OR	(290,229)	(3,084,347)	(290,316)	(3,374,663)	(290,316)	(3,664,979)	(290,316)	(3,955,295)	(290,316)	(4,245,611)
Washington	108TP	WA	-	-	-	-	-	-	-	-	-	-
Eastern Wyoming	108TP	WYP	-	-	-	-	-	-	-	-	-	-
Western Wyoming	108TP	WYU	-	-	-	-	-	-	-	-	-	-
Utah	108TP	UT	-	-	-	-	-	-	-	-	-	-
Idaho	108TP	ID	-	-	-	-	-	-	-	-	-	-
System	108TP	SG	(493,592)	(371,037,680)	(663,124)	(371,700,805)	(663,124)	(372,363,929)	(663,124)	(373,027,053)	(663,124)	(373,690,177)
Pre-merger Utah	108TP	SG	(537,493)	(445,702,018)	(832,545)	(446,534,563)	(832,545)	(447,367,107)	(832,545)	(448,199,652)	(832,545)	(449,032,197)
Post-merger	108TP	SG	(14,662,076)	(2,116,320,609)	(16,682,531)	(2,133,003,141)	(16,682,531)	(2,149,685,672)	(16,682,531)	(2,166,368,204)	(16,682,531)	(2,183,050,735)
System	108TP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Transmission Plant			(15,693,162)	(2,933,060,308)	(18,178,200)	(2,951,238,508)	(18,178,200)	(2,969,416,708)	(18,178,200)	(2,987,594,909)	(18,178,200)	(3,005,773,109)
Distribution Plant:												
California	108364	CA	(1,351,503)	(188,230,979)	(1,950,538)	(190,181,517)	(1,950,538)	(192,132,055)	(1,950,538)	(194,082,593)	(1,950,538)	(196,033,131)
Oregon	108364	OR	(4,671,653)	(1,336,376,502)	(6,950,732)	(1,343,327,234)	(6,950,732)	(1,350,277,966)	(6,950,732)	(1,357,228,698)	(6,950,732)	(1,364,179,430)
Washington	108364	WA	(1,168,063)	(347,536,658)	(1,640,430)	(349,177,088)	(1,640,430)	(350,817,518)	(1,640,430)	(352,457,948)	(1,640,430)	(354,098,378)
Eastern Wyoming	108364	WYP	(1,546,520)	(382,371,887)	(2,146,964)	(384,518,851)	(2,146,964)	(386,665,815)	(2,146,964)	(388,812,779)	(2,146,964)	(390,959,744)
Utah	108364	UT	(7,159,319)	(1,410,101,163)	(11,365,690)	(1,421,466,854)	(11,365,690)	(1,432,832,544)	(11,365,690)	(1,444,198,235)	(11,365,690)	(1,455,563,925)
Idaho	108364	ID	(617,186)	(192,530,965)	(1,207,407)	(193,738,372)	(1,207,407)	(194,945,779)	(1,207,407)	(196,153,186)	(1,207,407)	(197,360,592)
Western Wyoming	108364	WYU	(319,671)	(81,604,866)	(373,066)	(81,977,932)	(373,066)	(82,350,998)	(373,066)	(82,724,064)	(373,066)	(83,097,129)
Pre-merger Pacific	108363	SG	-	-	-	-	-	-	-	-	-	-
Pre-merger Utah	108363	SG	-	-	-	-	-	-	-	-	-	-
System	108363	SNPD	(90,545)	(30,811,049)	(90,545)	(30,901,594)	(90,545)	(30,992,139)	(90,545)	(31,082,684)	(90,545)	(31,173,228)
System	108363	CN	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)
System	108363	SO	-	-	-	-	-	-	-	-	-	-
System	108363	SG	-	-	-	-	-	-	-	-	-	-
System	108363	OTHER	-	-	-	-	-	-	-	-	-	-
Total Distribution Plant			(16,924,460)	(3,980,366,703)	(25,725,372)	(4,006,092,076)	(25,725,372)	(4,031,817,448)	(25,725,372)	(4,057,542,820)	(25,725,372)	(4,083,268,192)
Energy Storage Plant:												
California	108ES	CA	-	-	-	-	-	-	-	-	-	-
Oregon	108ES	OR	-	-	-	-	-	-	-	-	-	-
Washington	108ES	WA	-	-	-	-	-	-	-	-	-	-
Eastern Wyoming	108ES	WYP	-	-	-	-	-	-	-	-	-	-
Utah	108ES	UT	-	-	-	-	-	-	-	-	-	-
Idaho	108ES	ID	-	-	-	-	-	-	-	-	-	-
Western Wyoming	108ES	WYU	-	-	-	-	-	-	-	-	-	-
System	108ES	CN	-	-	-	-	-	-	-	-	-	-
System	108ES	SNPD	-	-	-	-	-	-	-	-	-	-
System	108ES	SG	-	-	-	-	-	-	-	-	-	-
System	108ES	SO	-	-	-	-	-	-	-	-	-	-
System	108ES	OTHER	-	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-	-	-

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Mar 2027	Adjustments	Adjusted Reserve Balance Apr 2027	Adjustments	Adjusted Reserve Balance May 2027	Adjustments	Adjusted Reserve Balance Jun 2027	Adjustments	Adjusted Reserve Balance Jul 2027
General Plant:												
California	108GP	CA	(14,541)	(7,014,888)	(64,798)	(7,079,685)	(64,798)	(7,144,483)	(64,798)	(7,209,281)	(64,798)	(7,274,078)
Oregon	108GP	OR	104,235	(66,774,409)	(604,528)	(67,378,937)	(604,528)	(67,983,465)	(604,528)	(68,587,993)	(604,528)	(69,192,522)
Washington	108GP	WA	(33,509)	(20,900,192)	(134,305)	(21,034,497)	(134,305)	(21,168,802)	(134,305)	(21,303,107)	(134,305)	(21,437,412)
Eastern Wyoming	108GP	WYP	(149,427)	(27,675,110)	(280,179)	(27,955,289)	(280,179)	(28,235,468)	(280,179)	(28,515,647)	(280,179)	(28,795,826)
Utah	108GP	UT	(383,453)	(105,730,624)	(914,220)	(106,644,844)	(914,220)	(107,559,064)	(914,220)	(108,473,285)	(914,220)	(109,387,505)
Idaho	108GP	ID	(81,189)	(19,942,045)	(168,865)	(20,110,910)	(168,865)	(20,279,775)	(168,865)	(20,448,640)	(168,865)	(20,617,505)
Western Wyoming	108GP	WYU	(34,288)	(7,529,494)	(51,841)	(7,581,335)	(51,841)	(7,633,176)	(51,841)	(7,685,016)	(51,841)	(7,736,857)
Pre-merger Pacific	108GP	DGP	8,215	(312,149)	(448)	(312,596)	(448)	(313,044)	(448)	(313,492)	(448)	(313,940)
Pre-merger Utah	108GP	DGU	25,574	(1,083,981)	(1,790)	(1,085,771)	(1,790)	(1,087,560)	(1,790)	(1,089,350)	(1,790)	(1,091,140)
Post-merger	108GP	SG	213,953	(56,508,318)	(537,928)	(57,046,246)	(537,928)	(57,584,174)	(537,928)	(58,122,103)	(537,928)	(58,660,031)
System	108GP	SO	(4,404,248)	(599,631,846)	(5,744,005)	(605,375,851)	(5,744,005)	(611,119,857)	(5,744,005)	(616,863,862)	(5,744,005)	(622,607,868)
System	108GP	SG	(161)	(151,081)	(492)	(151,573)	(492)	(152,065)	(492)	(152,557)	(492)	(153,049)
System	108GP	SG	-	-	-	-	-	-	-	-	-	-
System	108GP	SNPD	-	-	-	-	-	-	-	-	-	-
Customer Service	108GP	CN	(503,461)	(220,397,410)	(580,969)	(220,978,378)	(580,969)	(221,559,347)	(580,969)	(222,140,316)	(580,969)	(222,721,284)
Fuel Related	108GP	SE	3,798	(1,527,625)	(9,254)	(1,536,879)	(9,254)	(1,546,134)	(9,254)	(1,555,388)	(9,254)	(1,564,642)
Total General Plant			(5,248,502)	(1,135,179,171)	(9,093,622)	(1,144,272,793)	(9,093,622)	(1,153,366,415)	(9,093,622)	(1,162,460,037)	(9,093,622)	(1,171,553,659)
Mining Plant:												
Coal Mine	108MP	SE	-	-	-	-	-	-	-	-	-	-
Total Mining Plant			-	-	-	-	-	-	-	-	-	-
Total Depreciation Reserve			(90,451,713)	(16,309,456,993)	(112,787,106)	(16,422,244,099)	(112,787,106)	(16,535,031,204)	(112,787,106)	(16,647,818,310)	(112,787,106)	(16,760,605,416)
AMORTIZATION RESERVE												
Intangible Plant:												
California	111IP	CA	147	3,089	-	3,089	-	3,089	-	3,089	-	3,089
Customer Service	111IP	CN	154,776	3,250,306	-	3,250,306	-	3,250,306	-	3,250,306	-	3,250,306
Pre-merger Pacific	111IP	DGP	-	-	-	-	-	-	-	-	-	-
Idaho	111IP	ID	243	(994,906)	-	(994,906)	-	(994,906)	-	(994,906)	-	(994,906)
Oregon	111IP	OR	(511)	(167,857)	(736)	(168,594)	(736)	(169,330)	(736)	(170,067)	(736)	(170,803)
Fuel Related	111IP	SE	-	-	-	-	-	-	-	-	-	-
Post-merger	111IP	SG	(142,887)	(86,562,465)	(458,229)	(87,020,694)	(458,229)	(87,478,924)	(458,229)	(87,937,153)	(458,229)	(88,395,382)
Hydro Relicensing	111IP	SG-P	(223,581)	(55,917,944)	(223,581)	(56,141,525)	(223,581)	(56,365,106)	(223,581)	(56,588,688)	(223,581)	(56,812,269)
Hydro Relicensing	111IP	SG-U	(5,340)	(7,080,616)	(20,245)	(7,100,861)	(20,245)	(7,121,105)	(20,245)	(7,141,350)	(20,245)	(7,161,595)
Pre-merger Utah	111IP	DGU	1,109	(424,588)	(945)	(425,533)	(945)	(426,478)	(945)	(427,423)	(945)	(428,368)
General Office	111IP	SO	677,200	14,221,191	-	14,221,191	-	14,221,191	-	14,221,191	-	14,221,191
Utah	111IP	UT	(7,442)	(553,159)	(7,846)	(561,005)	(7,846)	(568,851)	(7,846)	(576,697)	(7,846)	(584,543)
Washington	111IP	WA	252	5,291	-	5,291	-	5,291	-	5,291	-	5,291
Eastern Wyoming	111IP	WYP	1,900	(369,588)	(4,773)	(374,361)	(4,773)	(379,135)	(4,773)	(383,908)	(4,773)	(388,682)
Western Wyoming	111IP	WYU	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant			455,865	(134,591,245)	(716,357)	(135,307,602)	(716,357)	(136,023,958)	(716,357)	(136,740,315)	(716,357)	(137,456,671)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Mar 2027	Adjustments	Adjusted Reserve Balance Apr 2027	Adjustments	Adjusted Reserve Balance May 2027	Adjustments	Adjusted Reserve Balance Jun 2027	Adjustments	Adjusted Reserve Balance Jul 2027
Hydro Production Plant:												
Pre-merger Pacific	111HP	DGP	-	-	-	-	-	-	-	-	-	-
Pre-merger Utah	111HP	DGU	-	-	-	-	-	-	-	-	-	-
Post-merger	111HP	SG	-	-	-	-	-	-	-	-	-	-
Post-merger Pacific	111HP	SG-P	(26,228)	(4,944,568)	(26,228)	(4,970,796)	(26,228)	(4,997,023)	(26,228)	(5,023,251)	(26,228)	(5,049,479)
Post-merger Utah	111HP	SG-U	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			(26,228)	(4,944,568)	(26,228)	(4,970,796)	(26,228)	(4,997,023)	(26,228)	(5,023,251)	(26,228)	(5,049,479)
Solar Production Plant:												
Oregon	111XP	OR	-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Utah	111XP	UT	-	-	-	-	-	-	-	-	-	-
Post-merger	111XP	SG	-	-	-	-	-	-	-	-	-	-
System	111XP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Solar Plant			-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Wind Production Plant:												
Oregon	111WP	OR	-	-	-	-	-	-	-	-	-	-
Utah	111WP	UT	-	-	-	-	-	-	-	-	-	-
Post-merger	111WP	SG	-	-	-	-	-	-	-	-	-	-
System	111WP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Wind Plant			-	-	-	-	-	-	-	-	-	-
Renewable Production Plant:												
Oregon	111RP	OR	-	-	-	-	-	-	-	-	-	-
Utah	111RP	UT	-	-	-	-	-	-	-	-	-	-
Post-merger	111RP	SG	-	-	-	-	-	-	-	-	-	-
System	111RP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Renewable Plant			-	-	-	-	-	-	-	-	-	-
Other Production Plant:												
Oregon	111OP	OR	-	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-	-
General Plant:												
California	111GP	CA	-	(512,304)	-	(512,304)	-	(512,304)	-	(512,304)	-	(512,304)
General Office	111GP	CN	-	-	-	-	-	-	-	-	-	-
Idaho	111GP	ID	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)
Oregon	111GP	OR	(6,282)	(5,384,983)	(6,282)	(5,391,265)	(6,282)	(5,397,547)	(6,282)	(5,403,828)	(6,282)	(5,410,110)
General Office	111GP	SO	(2,848)	(1,935,129)	(2,848)	(1,937,978)	(2,848)	(1,940,826)	(2,848)	(1,943,674)	(2,848)	(1,946,523)
Utah	111GP	UT	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)
Washington	111GP	WA	(8,458)	(2,442,350)	(8,458)	(2,450,808)	(8,458)	(2,459,266)	(8,458)	(2,467,724)	(8,458)	(2,476,182)
Eastern Wyoming	111GP	WYP	(289)	(4,744,308)	(289)	(4,744,597)	(289)	(4,744,886)	(289)	(4,745,174)	(289)	(4,745,463)
Western Wyoming	111GP	WYU	-	-	-	-	-	-	-	-	-	-
Total General Plant			(17,877)	(15,385,972)	(17,877)	(15,403,849)	(17,877)	(15,421,726)	(17,877)	(15,439,603)	(17,877)	(15,457,479)
Total Amortization Reserve			411,761	(155,201,204)	(760,461)	(155,961,666)	(760,461)	(156,722,127)	(760,461)	(157,482,588)	(760,461)	(158,243,049)
Total Depreciation & Amortization Reserve			(90,039,953)	(16,464,658,198)	(113,547,567)	(16,578,205,764)	(113,547,567)	(16,691,753,331)	(113,547,567)	(16,805,300,898)	(113,547,567)	(16,918,848,465)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Aug 2027	Adjustments	Adjusted Reserve Balance Sep 2027	Adjustments	Adjusted Reserve Balance Oct 2027	Adjustments	Adjusted Reserve Balance Nov 2027	Adjustments	Adjusted Reserve Balance Dec 2027
DEPRECIATION RESERVE												
Steam Production Plant:												
Pre-merger Pacific	108SP	SG	(4,214,952)	(975,938,423)	(4,214,952)	(980,153,375)	(4,214,952)	(984,368,327)	(4,214,952)	(988,583,279)	(4,214,952)	(992,798,231)
Pre-merger Utah	108SP	SG	(4,243,848)	(895,245,501)	(4,243,848)	(899,489,349)	(4,243,848)	(903,733,197)	(4,243,848)	(907,977,045)	(4,243,848)	(912,220,893)
Post-merger	108SP	SG	(27,822,844)	(4,542,113,693)	(27,822,844)	(4,569,936,537)	(27,822,844)	(4,597,759,382)	(27,822,844)	(4,625,582,226)	(27,822,844)	(4,653,405,070)
Oregon	108SP	OR	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)	-	(1,070,726)
Washington	108SP	WA	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)	-	(16,063,271)
California	108SP	CA	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)	-	(1,856,680)
Utah	108SP	UT	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)	-	(76,741,331)
Idaho	108SP	ID	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)	-	(8,297,223)
Eastern Wyoming	108SP	WYP	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)	-	(22,675,360)
Western Wyoming	108SP	WYU	-	-	-	-	-	-	-	-	-	-
Post-merger	108SP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Steam Plant			(36,281,644)	(6,540,002,208)	(36,281,644)	(6,576,283,852)	(36,281,644)	(6,612,565,496)	(36,281,644)	(6,648,847,141)	(36,281,644)	(6,685,128,785)
Hydro Production Plant:												
Pre-merger Pacific	108HP	SG	(333,392)	(146,514,028)	(333,392)	(146,847,420)	(333,392)	(147,180,812)	(333,392)	(147,514,204)	(333,392)	(147,847,596)
Pre-merger Utah	108HP	SG	(104,010)	(36,451,397)	(104,010)	(36,555,406)	(104,010)	(36,659,416)	(104,010)	(36,763,426)	(104,010)	(36,867,435)
Post-merger	108HP	SG	(48,910)	(8,470,042)	(48,910)	(8,518,952)	(48,910)	(8,567,862)	(48,910)	(8,616,772)	(48,910)	(8,665,682)
Post-merger	108HP	SG-P	(2,369,611)	(282,539,625)	(2,369,611)	(284,909,237)	(2,369,611)	(287,278,848)	(2,369,611)	(289,648,460)	(2,369,611)	(292,018,071)
Post-merger	108HP	SG-U	(791,005)	(108,230,100)	(791,005)	(109,021,104)	(791,005)	(109,812,109)	(791,005)	(110,603,114)	(791,005)	(111,394,119)
Total Hydro Plant			(3,646,928)	(582,205,192)	(3,646,928)	(585,852,120)	(3,646,928)	(589,499,048)	(3,646,928)	(593,145,975)	(3,646,928)	(596,792,903)
Solar Production Plant:												
Oregon	108XP	OR	(10,573)	(271,235)	(10,573)	(281,808)	(10,573)	(292,382)	(10,573)	(302,955)	(10,573)	(313,529)
Utah	108XP	UT	(2,116)	(137,344)	(2,116)	(139,459)	(2,116)	(141,575)	(2,116)	(143,691)	(2,116)	(145,806)
Post-merger	108XP	SG	-	(67,257)	-	(67,257)	-	(67,257)	-	(67,257)	-	(67,257)
System	108XP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Solar Plant			(12,689)	(475,835)	(12,689)	(488,524)	(12,689)	(501,213)	(12,689)	(513,903)	(12,689)	(526,592)
Wind Production Plant:												
Oregon	108WP	OR	-	-	-	-	-	-	-	-	-	-
Utah	108WP	UT	-	-	-	-	-	-	-	-	-	-
Post-merger	108WP	SG	(12,795,190)	(479,231,182)	(12,795,190)	(492,026,372)	(12,795,190)	(504,821,561)	(12,795,190)	(517,616,751)	(12,795,190)	(530,411,940)
System	108WP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Wind Plant			(12,795,190)	(479,231,182)	(12,795,190)	(492,026,372)	(12,795,190)	(504,821,561)	(12,795,190)	(517,616,751)	(12,795,190)	(530,411,940)
Renewable Production Plant:												
Oregon	108RP	OR	-	-	-	-	-	-	-	-	-	-
Utah	108RP	UT	-	-	-	-	-	-	-	-	-	-
Post-merger	108RP	SG	(252,156)	(108,221,076)	(252,156)	(108,473,232)	(252,156)	(108,725,387)	(252,156)	(108,977,543)	(252,156)	(109,229,698)
System	108RP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Renewable Plant			(252,156)	(108,221,076)	(252,156)	(108,473,232)	(252,156)	(108,725,387)	(252,156)	(108,977,543)	(252,156)	(109,229,698)

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Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Aug 2027	Adjustments	Adjusted Reserve Balance Sep 2027	Adjustments	Adjusted Reserve Balance Oct 2027	Adjustments	Adjusted Reserve Balance Nov 2027	Adjustments	Adjusted Reserve Balance Dec 2027
Other Production Plant:												
Pre-merger Pacific	108OP	SG-W	-	-	-	-	-	-	-	-	-	-
Pre-merger Utah	108OP	SG	-	-	-	-	-	-	-	-	-	-
Post-merger	108OP	SG	(5,933,449)	(777,499,937)	(5,933,449)	(783,433,386)	(5,933,449)	(789,366,835)	(5,933,449)	(795,300,284)	(5,933,449)	(801,233,733)
Oregon	108OP	OR	-	-	-	-	-	-	-	-	-	-
Utah	108OP	UT	-	-	-	-	-	-	-	-	-	-
System	108OP	SG	(355,540)	(67,407,010)	(355,540)	(67,762,550)	(355,540)	(68,118,090)	(355,540)	(68,473,629)	(355,540)	(68,829,169)
Total Other Plant			(6,288,989)	(844,906,947)	(6,288,989)	(851,195,936)	(6,288,989)	(857,484,925)	(6,288,989)	(863,773,913)	(6,288,989)	(870,062,902)
Transmission Plant:												
California	108TP	CA	-	-	-	-	-	-	-	-	-	-
Oregon	108TP	OR	(290,316)	(4,535,926)	(290,316)	(4,826,242)	(290,316)	(5,116,558)	(290,316)	(5,406,874)	(290,316)	(5,697,190)
Washington	108TP	WA	-	-	-	-	-	-	-	-	-	-
Eastern Wyoming	108TP	WYP	-	-	-	-	-	-	-	-	-	-
Western Wyoming	108TP	WYU	-	-	-	-	-	-	-	-	-	-
Utah	108TP	UT	-	-	-	-	-	-	-	-	-	-
Idaho	108TP	ID	-	-	-	-	-	-	-	-	-	-
System	108TP	SG	(663,124)	(374,353,302)	(663,124)	(375,016,426)	(663,124)	(375,679,550)	(663,124)	(376,342,674)	(663,124)	(377,005,798)
Pre-merger Utah	108TP	SG	(832,545)	(449,864,742)	(832,545)	(450,697,286)	(832,545)	(451,529,831)	(832,545)	(452,362,376)	(832,545)	(453,194,921)
Post-merger	108TP	SG	(16,682,531)	(2,199,733,267)	(16,682,531)	(2,216,415,798)	(16,682,531)	(2,233,098,330)	(16,682,531)	(2,249,780,861)	(16,682,531)	(2,266,463,393)
System	108TP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Transmission Plant			(18,178,200)	(3,023,951,310)	(18,178,200)	(3,042,129,510)	(18,178,200)	(3,060,307,711)	(18,468,516)	(3,083,892,785)	(18,468,516)	(3,102,361,302)
Distribution Plant:												
California	108364	CA	(1,950,538)	(197,983,669)	(1,950,538)	(199,934,207)	(1,950,538)	(201,884,745)	(1,950,538)	(203,835,284)	(1,950,538)	(205,785,822)
Oregon	108364	OR	(6,950,732)	(1,371,130,162)	(6,950,732)	(1,378,080,894)	(6,950,732)	(1,385,031,626)	(6,950,732)	(1,391,982,358)	(6,950,732)	(1,398,933,090)
Washington	108364	WA	(1,640,430)	(355,738,808)	(1,640,430)	(357,379,238)	(1,640,430)	(359,019,668)	(1,640,430)	(360,660,098)	(1,640,430)	(362,300,528)
Eastern Wyoming	108364	WYP	(2,146,964)	(393,106,708)	(2,146,964)	(395,253,672)	(2,146,964)	(397,400,636)	(2,146,964)	(399,547,600)	(2,146,964)	(401,694,564)
Utah	108364	UT	(11,365,690)	(1,466,929,616)	(11,365,690)	(1,478,295,306)	(11,365,690)	(1,489,660,997)	(11,365,690)	(1,501,026,687)	(11,365,690)	(1,512,392,378)
Idaho	108364	ID	(1,207,407)	(198,567,999)	(1,207,407)	(199,775,406)	(1,207,407)	(200,982,813)	(1,207,407)	(202,190,220)	(1,207,407)	(203,397,627)
Western Wyoming	108364	WYU	(373,066)	(83,470,195)	(373,066)	(83,843,261)	(373,066)	(84,216,327)	(373,066)	(84,589,393)	(373,066)	(84,962,458)
Pre-merger Pacific	108363	SG	-	-	-	-	-	-	-	-	-	-
Pre-merger Utah	108363	SG	-	-	-	-	-	-	-	-	-	-
System	108363	SNPD	(90,545)	(31,263,773)	(90,545)	(31,354,318)	(90,545)	(31,444,863)	(90,545)	(31,535,408)	(90,545)	(31,625,953)
System	108363	CN	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)	-	(10,802,634)
System	108363	SO	-	-	-	-	-	-	-	-	-	-
System	108363	SG	-	-	-	-	-	-	-	-	-	-
System	108363	OTHER	-	-	-	-	-	-	-	-	-	-
Total Distribution Plant			(25,725,372)	(4,108,993,564)	(25,725,372)	(4,134,718,937)	(25,725,372)	(4,160,444,309)	(25,725,372)	(4,186,169,681)	(25,725,372)	(4,211,895,053)
Energy Storage Plant:												
California	108ES	CA	-	-	-	-	-	-	-	-	-	-
Oregon	108ES	OR	-	-	-	-	-	-	-	-	-	-
Washington	108ES	WA	-	-	-	-	-	-	-	-	-	-
Eastern Wyoming	108ES	WYP	-	-	-	-	-	-	-	-	-	-
Utah	108ES	UT	-	-	-	-	-	-	-	-	-	-
Idaho	108ES	ID	-	-	-	-	-	-	-	-	-	-
Western Wyoming	108ES	WYU	-	-	-	-	-	-	-	-	-	-
System	108ES	CN	-	-	-	-	-	-	-	-	-	-
System	108ES	SNPD	-	-	-	-	-	-	-	-	-	-
System	108ES	SG	-	-	-	-	-	-	-	-	-	-
System	108ES	SO	-	-	-	-	-	-	-	-	-	-
System	108ES	OTHER	-	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-	-	-

PacifiCorp
Oregon General Rate Case - December 2027
June 2025 - December 2027 Depreciation & Amortization Reserve

Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Aug 2027	Adjustments	Adjusted Reserve Balance Sep 2027	Adjustments	Adjusted Reserve Balance Oct 2027	Adjustments	Adjusted Reserve Balance Nov 2027	Adjustments	Adjusted Reserve Balance Dec 2027
General Plant:												
California	108GP	CA	(64,798)	(7,338,876)	(64,798)	(7,403,674)	(64,798)	(7,468,471)	(64,798)	(7,533,269)	(64,798)	(7,598,067)
Oregon	108GP	OR	(604,528)	(69,797,050)	(604,528)	(70,401,578)	(604,528)	(71,006,106)	(604,528)	(71,610,634)	(604,528)	(72,215,163)
Washington	108GP	WA	(134,305)	(21,571,717)	(134,305)	(21,706,022)	(134,305)	(21,840,327)	(134,305)	(21,974,633)	(134,305)	(22,108,938)
Eastern Wyoming	108GP	WYP	(280,179)	(29,076,005)	(280,179)	(29,356,185)	(280,179)	(29,636,364)	(280,179)	(29,916,543)	(280,179)	(30,196,722)
Utah	108GP	UT	(914,220)	(110,301,725)	(914,220)	(111,215,946)	(914,220)	(112,130,166)	(914,220)	(113,044,386)	(914,220)	(113,958,606)
Idaho	108GP	ID	(168,865)	(20,786,370)	(168,865)	(20,955,235)	(168,865)	(21,124,100)	(168,865)	(21,292,965)	(168,865)	(21,461,829)
Western Wyoming	108GP	WYU	(51,841)	(7,788,698)	(51,841)	(7,840,539)	(51,841)	(7,892,380)	(51,841)	(7,944,220)	(51,841)	(7,996,061)
Pre-merger Pacific	108GP	DGP	(448)	(314,388)	(448)	(314,835)	(448)	(315,283)	(448)	(315,731)	(448)	(316,179)
Pre-merger Utah	108GP	DGU	(1,790)	(1,092,930)	(1,790)	(1,094,720)	(1,790)	(1,096,509)	(1,790)	(1,098,299)	(1,790)	(1,100,089)
Post-merger	108GP	SG	(537,928)	(59,197,959)	(537,928)	(59,735,887)	(537,928)	(60,273,816)	(537,928)	(60,811,744)	(537,928)	(61,349,672)
System	108GP	SO	(5,744,005)	(628,351,873)	(5,744,005)	(634,095,878)	(5,744,005)	(639,839,884)	(5,744,005)	(645,583,889)	(5,744,005)	(651,327,895)
System	108GP	SG	(492)	(153,541)	(492)	(154,032)	(492)	(154,524)	(492)	(155,016)	(492)	(155,508)
System	108GP	SG	-	-	-	-	-	-	-	-	-	-
System	108GP	SNPD	-	-	-	-	-	-	-	-	-	-
Customer Service	108GP	CN	(580,969)	(223,302,253)	(580,969)	(223,883,221)	(580,969)	(224,464,190)	(580,969)	(225,045,159)	(580,969)	(225,626,127)
Fuel Related	108GP	SE	(9,254)	(1,573,896)	(9,254)	(1,583,151)	(9,254)	(1,592,405)	(9,254)	(1,601,659)	(9,254)	(1,610,913)
Total General Plant			(9,093,622)	(1,180,647,281)	(9,093,622)	(1,189,740,903)	(9,093,622)	(1,198,834,525)	(9,093,622)	(1,207,928,147)	(9,093,622)	(1,217,021,769)
Mining Plant:												
Coal Mine	108MP	SE	-	-	-	-	-	-	-	-	-	-
Total Mining Plant			-	-	-	-	-	-	-	-	-	-
Total Depreciation Reserve			(112,565,106)	(16,873,170,522)	(112,565,106)	(16,985,735,627)	(112,565,106)	(17,098,300,733)	(112,565,106)	(17,210,865,839)	(112,565,106)	(17,323,430,944)
AMORTIZATION RESERVE												
Intangible Plant:												
California	111IP	CA	-	3,089	-	3,089	-	3,089	-	3,089	-	3,089
Customer Service	111IP	CN	-	3,250,306	-	3,250,306	-	3,250,306	-	3,250,306	-	3,250,306
Pre-merger Pacific	111IP	DGP	-	-	-	-	-	-	-	-	-	-
Idaho	111IP	ID	-	(994,906)	-	(994,906)	-	(994,906)	-	(994,906)	-	(994,906)
Oregon	111IP	OR	(736)	(171,539)	(736)	(172,276)	(736)	(173,012)	(736)	(173,749)	(736)	(174,485)
Fuel Related	111IP	SE	-	-	-	-	-	-	-	-	-	-
Post-merger	111IP	SG	(458,229)	(88,853,612)	(458,229)	(89,311,841)	(458,229)	(89,770,070)	(458,229)	(90,228,299)	(458,229)	(90,686,529)
Hydro Relicensing	111IP	SG-P	(223,581)	(57,035,850)	(223,581)	(57,259,431)	(223,581)	(57,483,013)	(223,581)	(57,706,594)	(223,581)	(57,930,175)
Hydro Relicensing	111IP	SG-U	(20,245)	(7,181,840)	(20,245)	(7,202,085)	(20,245)	(7,222,330)	(20,245)	(7,242,575)	(20,245)	(7,262,819)
Pre-merger Utah	111IP	DGU	(945)	(429,314)	(945)	(430,259)	(945)	(431,204)	(945)	(432,149)	(945)	(433,095)
General Office	111IP	SO	-	14,221,191	-	14,221,191	-	14,221,191	-	14,221,191	-	14,221,191
Utah	111IP	UT	(7,846)	(592,389)	(7,846)	(600,235)	(7,846)	(608,081)	(7,846)	(615,927)	(7,846)	(623,773)
Washington	111IP	WA	-	5,291	-	5,291	-	5,291	-	5,291	-	5,291
Eastern Wyoming	111IP	WYP	(4,773)	(393,455)	(4,773)	(398,229)	(4,773)	(403,002)	(4,773)	(407,776)	(4,773)	(412,549)
Western Wyoming	111IP	WYU	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant			(716,357)	(138,173,028)	(716,357)	(138,889,384)	(716,357)	(139,605,741)	(716,357)	(140,322,098)	(716,357)	(141,038,454)

PacifiCorp
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June 2025 - December 2027 Depreciation & Amortization Reserve

Description	Account	2020P Factor	Adjustments	Adjusted Reserve Balance Aug 2027	Adjustments	Adjusted Reserve Balance Sep 2027	Adjustments	Adjusted Reserve Balance Oct 2027	Adjustments	Adjusted Reserve Balance Nov 2027	Adjustments	Adjusted Reserve Balance Dec 2027
Hydro Production Plant:												
Pre-merger Pacific	111HP	DGP	-	-	-	-	-	-	-	-	-	-
Pre-merger Utah	111HP	DGU	-	-	-	-	-	-	-	-	-	-
Post-merger	111HP	SG	-	-	-	-	-	-	-	-	-	-
Post-merger Pacific	111HP	SG-P	(26,228)	(5,075,706)	(26,228)	(5,101,934)	(26,228)	(5,128,162)	(26,228)	(5,154,390)	(26,228)	(5,180,617)
Post-merger Utah	111HP	SG-U	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			(26,228)	(5,075,706)	(26,228)	(5,101,934)	(26,228)	(5,128,162)	(26,228)	(5,154,390)	(26,228)	(5,180,617)
Solar Production Plant:												
Oregon	111XP	OR	-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Utah	111XP	UT	-	-	-	-	-	-	-	-	-	-
Post-merger	111XP	SG	-	-	-	-	-	-	-	-	-	-
System	111XP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Solar Plant			-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)	-	(279,419)
Wind Production Plant:												
Oregon	111WP	OR	-	-	-	-	-	-	-	-	-	-
Utah	111WP	UT	-	-	-	-	-	-	-	-	-	-
Post-merger	111WP	SG	-	-	-	-	-	-	-	-	-	-
System	111WP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Wind Plant			-	-	-	-	-	-	-	-	-	-
Renewable Production Plant:												
Oregon	111RP	OR	-	-	-	-	-	-	-	-	-	-
Utah	111RP	UT	-	-	-	-	-	-	-	-	-	-
Post-merger	111RP	SG	-	-	-	-	-	-	-	-	-	-
System	111RP	OTHER	-	-	-	-	-	-	-	-	-	-
Total Renewable Plant			-	-	-	-	-	-	-	-	-	-
Other Production Plant:												
Oregon	111OP	OR	-	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-	-
General Plant:												
California	111GP	CA	-	(512,304)	-	(512,304)	-	(512,304)	-	(512,304)	-	(512,304)
General Office	111GP	CN	-	-	-	-	-	-	-	-	-	-
Idaho	111GP	ID	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)
Oregon	111GP	OR	(6,282)	(5,416,392)	(6,282)	(5,422,674)	(6,282)	(5,428,956)	(6,282)	(5,435,238)	(6,282)	(5,441,519)
General Office	111GP	SO	(2,848)	(1,949,371)	(2,848)	(1,952,219)	(2,848)	(1,955,068)	(2,848)	(1,957,916)	(2,848)	(1,960,764)
Utah	111GP	UT	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)
Washington	111GP	WA	(8,458)	(2,484,640)	(8,458)	(2,493,098)	(8,458)	(2,501,556)	(8,458)	(2,510,014)	(8,458)	(2,518,472)
Eastern Wyoming	111GP	WYP	(289)	(4,745,752)	(289)	(4,746,040)	(289)	(4,746,329)	(289)	(4,746,617)	(289)	(4,746,906)
Western Wyoming	111GP	WYU	-	-	-	-	-	-	-	-	-	-
Total General Plant			(17,877)	(15,475,356)	(17,877)	(15,493,233)	(17,877)	(15,511,110)	(17,877)	(15,528,987)	(17,877)	(15,546,864)
Total Amortization Reserve			(760,461)	(159,003,510)	(760,461)	(159,763,971)	(760,461)	(160,524,432)	(760,461)	(161,284,893)	(760,461)	(162,045,354)
Total Depreciation & Amortization Reserve			(113,325,567)	(17,032,174,032)	(113,325,567)	(17,145,499,598)	(113,325,567)	(17,258,825,165)	(113,325,567)	(17,372,150,732)	(113,325,567)	(17,485,476,299)

PacifiCorp
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June 2025 - December 2027 Depreciation & Amortization Reserve

Description	Account	2020P Factor	CY 2027 Reserve 13 Month Average
DEPRECIATION RESERVE			
Steam Production Plant:			
Pre-merger Pacific	108SP	SG	(967,591,840)
Pre-merger Utah	108SP	SG	(886,907,518)
Post-merger	108SP	SG	(4,488,247,535)
Oregon	108SP	OR	(1,070,726)
Washington	108SP	WA	(16,063,271)
California	108SP	CA	(1,856,680)
Utah	108SP	UT	(76,741,331)
Idaho	108SP	ID	(8,297,223)
Eastern Wyoming	108SP	WYP	(22,675,360)
Western Wyoming	108SP	WYU	-
Post-merger	108SP	OTHER	-
Total Steam Plant			(6,469,451,484)
Hydro Production Plant:			
Pre-merger Pacific	108HP	SG	(145,860,861)
Pre-merger Utah	108HP	SG	(36,252,185)
Post-merger	108HP	SG	(8,372,222)
Post-merger	108HP	SG-P	(277,475,302)
Post-merger	108HP	SG-U	(106,694,211)
Total Hydro Plant			(574,654,781)
Solar Production Plant:			
Oregon	108XP	OR	(250,088)
Utah	108XP	UT	(133,169)
Post-merger	108XP	SG	(67,257)
System	108XP	OTHER	-
Total Solar Plant			(450,514)
Wind Production Plant:			
Oregon	108WP	OR	-
Utah	108WP	UT	-
Post-merger	108WP	SG	(453,594,625)
System	108WP	OTHER	-
Total Wind Plant			(453,594,625)
Renewable Production Plant:			
Oregon	108RP	OR	-
Utah	108RP	UT	-
Post-merger	108RP	SG	(107,717,078)
System	108RP	OTHER	-
Total Renewable Plant			(107,717,078)

PacifiCorp
Oregon General Rate Case - December 2027
June 2025 - December 2027 Depreciation & Amortization Reserve

Description	Account	2020P Factor	CY 2027 Reserve 13 Month Average
Other Production Plant:			
Pre-merger Pacific	108OP	SG-W	-
Pre-merger Utah	108OP	SG	-
Post-merger	108OP	SG	(766,750,632)
Oregon	108OP	OR	-
Utah	108OP	UT	-
System	108OP	SG	(66,709,588)
Total Other Plant			(833,460,220)
Transmission Plant:			
California	108TP	CA	-
Oregon	108TP	OR	(3,955,388)
Washington	108TP	WA	-
Eastern Wyoming	108TP	WYP	-
Western Wyoming	108TP	WYU	-
Utah	108TP	UT	-
Idaho	108TP	ID	-
System	108TP	SG	(373,105,225)
Pre-merger Utah	108TP	SG	(448,335,704)
Post-merger	108TP	SG	(2,167,321,401)
System	108TP	OTHER	-
Total Transmission Plant			(2,992,717,717)
Distribution Plant:			
California	108364	CA	(194,365,011)
Oregon	108364	OR	(1,358,283,318)
Washington	108364	WA	(352,676,756)
Eastern Wyoming	108364	WYP	(389,091,675)
Utah	108364	UT	(1,446,148,347)
Idaho	108364	ID	(196,426,924)
Western Wyoming	108364	WYU	(82,748,670)
Pre-merger Pacific	108363	SG	-
Pre-merger Utah	108363	SG	-
System	108363	SNPD	(31,082,684)
System	108363	CN	(10,802,634)
System	108363	SO	-
System	108363	SG	-
System	108363	OTHER	-
Total Distribution Plant			(4,061,626,019)
Energy Storage Plant:			
California	108ES	CA	-
Oregon	108ES	OR	-
Washington	108ES	WA	-
Eastern Wyoming	108ES	WYP	-
Utah	108ES	UT	-
Idaho	108ES	ID	-
Western Wyoming	108ES	WYU	-
System	108ES	CN	-
System	108ES	SNPD	-
System	108ES	SG	-
System	108ES	SO	-
System	108ES	OTHER	-
Total Energy Storage Plant			-

PacifiCorp
Oregon General Rate Case - December 2027
June 2025 - December 2027 Depreciation & Amortization Reserve

Description	Account	2020P Factor	CY 2027 Reserve 13 Month Average
General Plant:			
California	108GP	CA	(7,232,465)
Oregon	108GP	OR	(68,914,909)
Washington	108GP	WA	(21,349,599)
Eastern Wyoming	108GP	WYP	(28,576,025)
Utah	108GP	UT	(108,718,263)
Idaho	108GP	ID	(20,489,112)
Western Wyoming	108GP	WYU	(7,693,112)
Pre-merger Pacific	108GP	DGP	(317,488)
Pre-merger Utah	108GP	DGU	(1,101,971)
Post-merger	108GP	SG	(58,468,626)
System	108GP	SO	(617,485,209)
System	108GP	SG	(152,709)
System	108GP	SG	-
System	108GP	SNPD	-
Customer Service	108GP	CN	(222,176,030)
Fuel Related	108GP	SE	(1,561,399)
Total General Plant			(1,164,236,916)
Mining Plant:			
Coal Mine	108MP	SE	-
Total Mining Plant			-
Total Depreciation Reserve			(16,657,909,354)
AMORTIZATION RESERVE			
Intangible Plant:			
California	111IP	CA	3,021
Customer Service	111IP	CN	3,178,870
Pre-merger Pacific	111IP	DGP	-
Idaho	111IP	ID	(995,018)
Oregon	111IP	OR	(170,171)
Fuel Related	111IP	SE	-
Post-merger	111IP	SG	(88,082,469)
Hydro Relicensing	111IP	SG-P	(56,588,688)
Hydro Relicensing	111IP	SG-U	(7,148,220)
Pre-merger Utah	111IP	DGU	(428,370)
General Office	111IP	SO	13,908,637
Utah	111IP	UT	(576,883)
Washington	111IP	WA	5,175
Eastern Wyoming	111IP	WYP	(386,986)
Western Wyoming	111IP	WYU	-
Total Intangible Plant			(137,281,100)

PacifiCorp
Oregon General Rate Case - December 2027
June 2025 - December 2027 Depreciation & Amortization Reserve

Description	Account	2020P Factor	CY 2027 Reserve 13 Month Average
Hydro Production Plant:			
Pre-merger Pacific	111HP	DGP	-
Pre-merger Utah	111HP	DGU	-
Post-merger	111HP	SG	-
Post-merger Pacific	111HP	SG-P	(5,023,251)
Post-merger Utah	111HP	SG-U	-
Total Hydro Plant			(5,023,251)
Solar Production Plant:			
Oregon	111XP	OR	(279,419)
Utah	111XP	UT	-
Post-merger	111XP	SG	-
System	111XP	OTHER	-
Total Solar Plant			(279,419)
Wind Production Plant:			
Oregon	111WP	OR	-
Utah	111WP	UT	-
Post-merger	111WP	SG	-
System	111WP	OTHER	-
Total Wind Plant			-
Renewable Production Plant:			
Oregon	111RP	OR	-
Utah	111RP	UT	-
Post-merger	111RP	SG	-
System	111RP	OTHER	-
Total Renewable Plant			-
Other Production Plant:			
Oregon	111OP	OR	-
Total Other Plant			-
General Plant:			
California	111GP	CA	(512,304)
General Office	111GP	CN	-
Idaho	111GP	ID	(333,771)
Oregon	111GP	OR	(5,403,828)
General Office	111GP	SO	(1,943,674)
Utah	111GP	UT	(33,127)
Washington	111GP	WA	(2,467,724)
Eastern Wyoming	111GP	WYP	(4,745,174)
Western Wyoming	111GP	WYU	-
Total General Plant			(15,439,603)
Total Amortization Reserve			(158,023,373)
Total Depreciation & Amortization Reserve			**(16,815,932,727)**
			Ref. 6.2.5

PacifiCorp
Oregon General Rate Case - December 2027
Hydro Decommissioning
Tax Summary

	Tax Deduction	Addback: Book Amortization	Book-Tax Difference	Deferred Income Tax Expense	Accumulated Deferred Income Tax
December-26	105,500	-	(105,500)	25,939	281,830
January-27	-	-	-	-	281,830
February-27	-	-	-	-	281,830
March-27	-	-	-	-	281,830
April-27	-	-	-	-	281,830
May-27	-	-	-	-	281,830
June-27	-	-	-	-	281,830
July-27	-	-	-	-	281,830
August-27	222,000	-	(222,000)	54,582	227,248
September-27	222,000	-	(222,000)	54,582	172,666
October-27	222,000	-	(222,000)	54,582	118,084
November-27	222,000	-	(222,000)	54,582	63,502
December-27	222,000	-	(222,000)	54,582	8,920
TOTAL	1,110,000	-	(1,110,000)	272,910	
				13 Mo. Average	**218,851**
					Ref 6.2

PacifiCorp
Oregon General Rate Case - December 2027
Oregon Coal-Fired Steam Plant Depreciation

Depreciation Reserve Adjustment By Plant

Plant	Factor	Adjustment to Reserve (Year Ended June 2025)
NAUGHTON	SG	(108,902,951)
HUNTINGTON	SG	(157,672,263)
HUNTER	SG	(309,389,205)
CRAIG	SG	4,386,372
HAYDEN	SG	(32,743,160)
COLSTRIP	SG	(9,430,258)
DAVE JOHNSTON	SG	(2,113,056)
JIM BRIDGER	SG	(453,420,287)
WYODAK	SG	(112,298,071)
		(1,181,582,879)

Description of Adjustment:

This is the increase in the depreciation reserve June 2025 starting balance in adjustment 6.2. This reflects the increase from January 2008 to June 2025 to reflect the different depreciation rates Oregon is using for the coal-fired generating plants. This was approved in the Depreciation Study, in Docket UM-1329 Order 08-427, with rates effective January 1, 2008. This balance also includes the impact to the June 2025 depreciation reserve from the change to depreciable lives ordered in UE-399 & UE-433.

PacifiCorp
Oregon General Rate Case - December 2027
Coal Depreciable Life Update
Change in Depreciation Expense & Reserve from UE-399

	PROPOSED END OF DEPRECIABLE LIFE	AS OF DEC 31, 2022 ORIGINAL COST	ACCUM. RESERVES	FUTURE ACCURALS	ACCEL. DEPR. RATES ANNUAL AMOUNT	ACCRUAL RATE	COMPOSITE REMAINING LIFE	EXISTING RATES CURRENT RATE[1]	CURRENT ACCRUAL	CHANGE
COLSTRIP GENERATING STATION	12-2025	245,683,766	190,060,942	71,638,975	25,796,827	10.50	2.8	5.71	13,996,713	11,800,114
CRAIG UNIT 2	09-2028	108,124,258	77,817,819	32,395,594	5,692,211	5.27	5.7	7.98	8,660,238	(2,968,027)
CRAIG COMMON	09-2028	52,548,072	45,115,710	8,291,679	1,449,040	2.76	5.7	5.69	2,975,274	(1,526,234)
HAYDEN UNIT 1	12-2028	55,376,031	50,125,428	5,804,363	969,756	1.75	6.0	11.67	6,455,275	(5,485,519)
HAYDEN UNIT 2	12-2027	32,275,692	29,254,112	3,344,337	668,232	2.07	5.0	11.85	3,833,821	(3,165,589)
HAYDEN COMMON	12-2028	28,208,413	26,025,830	2,316,267	385,285	1.37	6.0	7.63	2,149,014	(1,763,729)
		522,216,232	418,399,841	123,791,214	34,961,351				38,070,335	**(3,108,984)**

Ref. 6.2.1

Note 1 - Current rates are per approved 2018 Depreciation Study.

Depreciation Reserve Impact*	**Per Month**	**Balance**
July-25	259,082	259,082
August-25	259,082	518,164
September-25	259,082	777,246
October-25	259,082	1,036,328
November-25	259,082	1,295,410
December-25	259,082	1,554,492
January-26	259,082	1,813,574
February-26	259,082	2,072,656
March-26	259,082	2,331,738
April-26	259,082	2,590,820
May-26	259,082	2,849,902
June-26	259,082	3,108,984
July-26	259,082	3,368,066
August-26	259,082	3,627,148
September-26	259,082	3,886,230
October-26	259,082	4,145,312
November-26	259,082	4,404,395
December-26	259,082	4,663,477
January-27	259,082	4,922,559
February-27	259,082	5,181,641
March-27	259,082	5,440,723
April-27	259,082	5,699,805
May-27	259,082	5,958,887
June-27	259,082	6,217,969
July-27	259,082	6,477,051
August-27	259,082	6,736,133
September-27	259,082	6,995,215
October-27	259,082	7,254,297
November-27	259,082	7,513,379
December-27	259,082	7,772,461

13 Month Avg.
6,217,969 **Incremental Reserve Impact**

Ref. 6.2.1

*The depreciation reserve impact for January 2023 through June 2025 is adjusted for in the Oregon-Coal-Fired Steam Plant Deprecation Back up Page 6.2.5

PacifiCorp
Oregon General Rate Case - December 2027
Coal Depreciable Life Update
Change in Depreciation Expense & Reserve from UE-433

	PROPOSED END OF DEPRECIABLE LIFE	PROJECTED AS OF DEC 31, 2024 ORIGINAL COST	ACCUM. RESERVES	FUTURE ACCURALS	ACCEL. DEPR. RATES ANNUAL AMOUNT	ACCRUAL RATE	COMPOSITE REMAINING LIFE	EXISTING RATES CURRENT RATE[1]	CURRENT ACCRUAL	CHANGE
DAVE JOHNSTON UNIT 1	12-2028	79,194,413	62,411,931	19,756,091	5,188,820	6.55	3.8	4.84	3,790,375	1,398,445
DAVE JOHNSTON UNIT 2	12-2028	84,415,384	67,354,095	20,395,792	5,360,016	6.35	3.8	4.78	4,043,334	1,316,682
DAVE JOHNSTON UNIT 4	12-2029	322,342,650	254,877,430	77,616,085	15,876,632	4.93	4.9	4.83	15,545,002	331,630
DAVE JOHNSTON COMMON	12-2029	319,529,695	280,563,708	48,548,879	9,835,733	3.08	4.9	4.55	14,522,217	(4,686,484)
NAUGHTON UNIT 1	12-2036	225,938,807	207,649,229	36,371,292	3,057,481	1.35	11.9	12.00	27,090,654	(24,033,173)
NAUGHTON UNIT 2	12-2036	289,265,816	255,835,122	56,590,366	4,744,031	1.64	11.9	12.09	35,019,809	(30,275,778)
NAUGHTON COMMON	12-2036	120,231,319	75,204,074	54,998,059	4,652,240	3.87	11.8	6.20	7,470,265	(2,818,025)
JIM BRIDGER UNIT 1	12-2037	231,847,132	196,811,501	44,316,671	3,401,680	1.47	13.0	1.67	3,827,442	(425,762)
JIM BRIDGER UNIT 2	12-2037	243,209,418	187,215,788	65,722,006	5,101,127	2.09	12.9	3.27	7,932,961	(2,831,834)
JIM BRIDGER UNIT 3	12-2028	343,609,136	305,260,283	53,515,586	13,720,200	3.99	3.9	9.60	32,997,332	(19,277,131)
JIM BRIDGER UNIT 4	12-2028	412,915,041	386,335,725	45,750,827	11,714,158	2.84	3.9	9.49	39,123,030	(27,408,872)
JIM BRIDGER COMMON	12-2037	239,346,348	165,390,324	83,518,633	6,450,570	2.69	13.0	3.55	8,776,600	(2,326,030)
		2,911,845,158	2,444,909,211	607,100,286	89,102,688				200,139,020	**(111,036,332)**

Ref. 6.2.1

Note 1 - Current rates are per approved 2018 Depreciation Study.

Depreciation Reserve Impact*	Per Month	Balance
July-25	9,253,028	9,253,028
August-25	9,253,028	18,506,055
September-25	9,253,028	27,759,083
October-25	9,253,028	37,012,111
November-25	9,253,028	46,265,138
December-25	9,253,028	55,518,166
January-26	9,253,028	64,771,194
February-26	9,253,028	74,024,221
March-26	9,253,028	83,277,249
April-26	9,253,028	92,530,276
May-26	9,253,028	101,783,304
June-26	9,253,028	111,036,332
July-26	9,253,028	120,289,359
August-26	9,253,028	129,542,387
September-26	9,253,028	138,795,415
October-26	9,253,028	148,048,442
November-26	9,253,028	157,301,470
December-26	9,253,028	166,554,498
January-27	9,253,028	175,807,525
February-27	9,253,028	185,060,553
March-27	9,253,028	194,313,581
April-27	9,253,028	203,566,608
May-27	9,253,028	212,819,636
June-27	9,253,028	222,072,664
July-27	9,253,028	231,325,691
August-27	9,253,028	240,578,719
September-27	9,253,028	249,831,746
October-27	9,253,028	259,084,774
November-27	9,253,028	268,337,802
December-27	9,253,028	277,590,829
	Ref. 6.2.1	

13 Month Avg.
222,072,664 **Incremental Reserve Impact**

*The depreciation reserve impact for January 2025 through June 2025 is adjusted for in the Oregon-Coal-Fired Steam Plant Deprecation Back up Page 6.2.5

PacifiCorp
Oregon General Rate Case - December 2027
Hydro Decommissioning
Spending, Accruals, and Balances - East Side, West Side, and Total Resources

West Side	Spend	Accruals	Balance
June-24	-	60,700	(3,771,585)
July-24	-	60,700	(3,710,886)
August-24	-	60,700	(3,650,186)
September-24	-	60,700	(3,589,486)
October-24	-	60,700	(3,528,787)
November-24	-	60,700	(3,468,087)
December-24	-	60,700	(3,407,387)
January-25	-	60,700	(3,346,688)
February-25	-	60,700	(3,285,988)
March-25	-	60,700	(3,225,288)
April-25	-	60,700	(3,164,588)
May-25	-	60,700	(3,103,889)
June-25	-	60,700	(3,043,189)
Base Period Year End			**(3,043,189)**

East Side	Spend	Accruals	Balance
June-24	-	(23,356)	(1,130,293)
July-24	-	(23,356)	(1,153,649)
August-24	-	(23,356)	(1,177,005)
September-24	-	(23,356)	(1,200,361)
October-24	-	(23,356)	(1,223,717)
November-24	-	(23,356)	(1,247,073)
December-24	-	(23,356)	(1,270,428)
January-25	-	(23,356)	(1,293,784)
February-25	461,742	(23,356)	(855,399)
March-25	25,645	(23,356)	(853,110)
April-25	10,550	(23,356)	(865,916)
May-25	55,624	(23,356)	(833,648)
June-25	7,685	(23,356)	(849,319)
Base Period Year End			**(849,319)**

Total Resources	Spend	Accruals	Balance
June-24	-	37,344	(4,901,878)
July-24	-	37,344	(4,864,534)
August-24	-	37,344	(4,827,191)
September-24	-	37,344	(4,789,847)
October-24	-	37,344	(4,752,503)
November-24	-	37,344	(4,715,160)
December-24	-	37,344	(4,677,816)
January-25	-	37,344	(4,640,472)
February-25	461,742	37,344	(4,141,387)
March-25	25,645	37,344	(4,078,398)
April-25	10,550	37,344	(4,030,504)
May-25	55,624	37,344	(3,937,537)
June-25	7,685	37,344	(3,892,508)
Base Period Year End			**(3,892,508)**

West Side	Spend	Accruals	Balance
December-26	105,500	-	**(990,991)**
January-27	-	-	(990,991)
February-27	-	-	(990,991)
March-27	-	-	(990,991)
April-27	-	-	(990,991)
May-27	-	-	(990,991)
June-27	-	-	(990,991)
July-27	-	-	(990,991)
August-27	222,000	-	(768,991)
September-27	222,000	-	(546,991)
October-27	222,000	-	(324,991)
November-27	222,000	-	(102,991)
December-27	222,000	-	**119,009**

East Side	Spend	Accruals	Balance
December-26	-	-	**(155,284)**
January-27	-	-	(155,284)
February-27	-	-	(155,284)
March-27	-	-	(155,284)
April-27	-	-	(155,284)
May-27	-	-	(155,284)
June-27	-	-	(155,284)
July-27	-	-	(155,284)
August-27	-	-	(155,284)
September-27	-	-	(155,284)
October-27	-	-	(155,284)
November-27	-	-	(155,284)
December-27	-	-	**(155,284)**

Total Resources	Spend	Accruals	Balance
December-26	105,500	-	**(1,146,275)**
January-27	-	-	(1,146,275)
February-27	-	-	(1,146,275)
March-27	-	-	(1,146,275)
April-27	-	-	(1,146,275)
May-27	-	-	(1,146,275)
June-27	-	-	(1,146,275)
July-27	-	-	(1,146,275)
August-27	222,000	-	(924,275)
September-27	222,000	-	(702,275)
October-27	222,000	-	(480,275)
November-27	222,000	-	(258,275)
December-27	222,000	-	**(36,275)**

West Side	Total Spend	Total Accruals	Dec 27 13 Mo. Average Balance
12 ME Dec 2027	1,110,000	-	**(734,837)**
		Adjustment to Reserve	**2,308,352**

East Side	Total Spend	Total Accruals	Dec 27 13 Mo. Average Balance
12 ME Dec 2027	-	-	**(155,284)**
		Adjustment to Reserve	**694,035**

Total Resources	Total Spend	Total Accruals	Dec 27 13 Mo. Average Balance
12 ME Dec 2027	1,110,000	-	**(890,121)**
		Adjustment to Reserve	**3,002,387**

PacifiCorp PAGE 6.3
Oregon General Rate Case - December 2027
Repowering Buy-Downs Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense							
Repowered Buy-Down	407	1	(6,748,553)	OR	Situs	(6,748,553)	6.3.1
Total			(6,748,553)			(6,748,553)	
Adjustment to Reserves							
RAC buy-down reserves adj.	108WP	1	(166,324,084)	OR	Situs	(166,324,084)	6.3.2
Repowered Facilities Reserve	108WP	3	16,871,383	OR	Situs	16,871,383	6.3.2
			(149,452,701)			(149,452,701)	

Description of Adjustment:

This adjustment corrects the allocation of expenses recorded as a result of the buy-down in the base period for the repowered wind facilities, as well as brings into rate base the accumulated reserves adjustment for wind facilities buy-downs for all repowered projects. Also reflected in this adjustment is the on-going amortization of this buy-down reserve balance to appropriately reflect these balances at Test Year levels. As the underlying wind assets depreciates, these buy-down reserves also need to be amortized in the opposite direction to offset Oregon's share of depreciation expense recorded for the repowered projects.

PacifiCorp
Oregon General Rate Case - December 2027
Repowering Buy-Downs Adjustment
Twelve Months Ended June 2025 - Actual Amortization

Account	Actual FERC Account	Revised FERC Account	Text	Booked Alloc.	Correct Alloc.	Amount
565243	403	407	Depr Adj - Dunlap OR Wind Buydown	NUTIL	OR	(896,328)
565243	403	407	Depr Adj - Foote Creek OR Wind Buydown	NUTIL	OR	(88,212)
565243	403	407	Depr Adj - Glenrock 1 OR Wind Buydown	NUTIL	OR	(679,667)
565243	403	407	Depr Adj - Glenrock 3 OR Wind Buydown	NUTIL	OR	(245,997)
565243	403	407	Depr Adj - Goodnoe Hills OR Wind Buydown	NUTIL	OR	(795,704)
565243	403	407	Depr Adj - High Plains OR Wind Buydown	NUTIL	OR	(888,503)
565243	403	407	Depr Adj - Leaning Juniper OR Wind Buydown	NUTIL	OR	(581,162)
565243	403	407	Depr Adj - Marengo 1 OR Wind Buydown	NUTIL	OR	(901,133)
565243	403	407	Depr Adj - Marengo 2 OR Wind Buydown	NUTIL	OR	(477,864)
565243	403	407	Depr Adj - McFadden Ridge OR Wind Buydown	NUTIL	OR	(226,774)
565243	403	407	Depr Adj - Seven Mile Hill 1 OR Wind Buydown	NUTIL	OR	(800,555)
565243	403	407	Depr Adj - Seven Mile Hill 2 OR Wind Buydown	NUTIL	OR	(166,655)
						(6,748,553)

Ref 6.3

PacifiCorp
Oregon General Rate Case - December 2027
Repowering Buy-Downs Adjustment

	Beginning Balance	Amortization Expense	Ending Balance	
July-24	(173,072,637)	(562,379)	(172,510,258)	
August-24	(172,510,258)	(562,379)	(171,947,878)	
September-24	(171,947,878)	(562,379)	(171,385,499)	
October-24	(171,385,499)	(562,379)	(170,823,120)	
November-24	(170,823,120)	(562,379)	(170,260,740)	
December-24	(170,260,740)	(562,379)	(169,698,361)	
January-25	(169,698,361)	(562,379)	(169,135,981)	
February-25	(169,135,981)	(562,379)	(168,573,602)	
March-25	(168,573,602)	(562,379)	(168,011,222)	
April-25	(168,011,222)	(562,379)	(167,448,843)	
May-25	(167,448,843)	(562,379)	(166,886,464)	
June-25	(166,886,464)	(562,379)	**(166,324,084)**	**Ref 6.3**
Base Period Amortization		*(6,748,553)*		
July-25	(166,324,084)	(562,379)	(165,761,705)	
August-25	(165,761,705)	(562,379)	(165,199,325)	
September-25	(165,199,325)	(562,379)	(164,636,946)	
October-25	(164,636,946)	(562,379)	(164,074,566)	
November-25	(164,074,566)	(562,379)	(163,512,187)	
December-25	(163,512,187)	(562,379)	(162,949,808)	
January-26	(162,949,808)	(562,379)	(162,387,428)	
February-26	(162,387,428)	(562,379)	(161,825,049)	
March-26	(161,825,049)	(562,379)	(161,262,669)	
April-26	(161,262,669)	(562,379)	(160,700,290)	
May-26	(160,700,290)	(562,379)	(160,137,910)	
June-26	(160,137,910)	(562,379)	(159,575,531)	
July-26	(159,575,531)	(562,379)	(159,013,152)	
August-26	(159,013,152)	(562,379)	(158,450,772)	
September-26	(158,450,772)	(562,379)	(157,888,393)	
October-26	(157,888,393)	(562,379)	(157,326,013)	
November-26	(157,326,013)	(562,379)	(156,763,634)	
December-26	(156,763,634)	(562,379)	(156,201,254)	
January-27	(156,201,254)	(562,379)	(155,638,875)	
February-27	(155,638,875)	(562,379)	(155,076,496)	
March-27	(155,076,496)	(562,379)	(154,514,116)	
April-27	(154,514,116)	(562,379)	(153,951,737)	
May-27	(153,951,737)	(562,379)	(153,389,357)	
June-27	(153,389,357)	(562,379)	(152,826,978)	
July-27	(152,826,978)	(562,379)	(152,264,598)	
August-27	(152,264,598)	(562,379)	(151,702,219)	
September-27	(151,702,219)	(562,379)	(151,139,840)	
October-27	(151,139,840)	(562,379)	(150,577,460)	
November-27	(150,577,460)	(562,379)	(150,015,081)	
December-27	(150,015,081)	(562,379)	**(149,452,701)**	**Ref 6.3**
Pro Forma Period Amortization		*(6,748,553)*		

Base Period Amortization Expense	(6,748,553)	Above
Pro Forma Amortization Expense	(6,748,553)	Above
Adjustment to Expense	**-**	

Base Period Accum. Amort.	(166,324,084)	Above
Pro Forma Accum. Amort.	(149,452,701)	Above
Adjustment to Accum.	**16,871,383**	**Ref 6.3**

PacifiCorp PAGE 6.4 - REDACTED
Oregon General Rate Case - December 2027
Confidential Bridger Mine Reclamation Costs and Decommissioning Cost

Note: Please see Confidential Exhibit PAC/807_CONF for redacted information.

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Bridger Reclamation Costs	501	3	[redacted]	SE	26.823%	[redacted]	6.4.1
Annual Incremental Decomm. Costs	407	3	12,974,220	SG	27.756%	3,601,069	6.4.2
Adjustment to Rate Base							
Bridger Reclamation Costs	254	3	[redacted]	OR	Situs	[redacted]	6.4.1
Remove Base Accum. Reg Liab. - Incr. Decomm.	108SP	3	1,070,726	OR	Situs	1,070,726	B-17
Remove Base Accum. Reg Liab. - Incr. Closure	254	3	673,279	OR	Situs	673,279	B-15
Accum. Reg Liab.-Incr. Decomm. & Closure	254	3	(32,435,550)	SG	27.756%	(9,002,673)	6.4.2
Adjustment to Tax:							
Sch M Adj. - Bridger Reclamation	SCHMAT	3	[redacted]	SE	26.823%	[redacted]	6.4.1
DIT Expense	41110	3	[redacted]	SE	26.823%	[redacted]	6.4.1
Accum. DIT Balance	190	3	[redacted]	OR	Situs	[redacted]	6.4.1
Sch M Adj. - Incr. Decomm. & Clos.	SCHMAT	3	12,974,220	SG	27.756%	3,601,069	6.4.2
DIT Expense	41110	3	(3,189,924)	SG	27.756%	(885,382)	6.4.2
Accum. DIT Balance	190	3	7,974,810	SG	27.756%	2,213,454	6.4.2
Remove Base Sch M Adj. - Steam Decomm.	SCHMAT	3	(1,070,726)	OR	Situs	(1,070,726)	
Remove Base DIT Expense	41110	3	263,255	OR	Situs	263,255	
Remove Base Accum. DIT Balance	190	3	(263,255)	OR	Situs	(263,255)	
Remove Base Sch M Adj. - Bridger Reclamation	SCHMAT	3	[redacted]	OR	Situs	[redacted]	
Remove Base DIT Expense	41110	3	[redacted]	OR	Situs	[redacted]	
Remove Base Sch M Adj. - Other Plant Closure	SCHMAT	3	(673,279)	OR	Situs	(673,279)	
Remove Base DIT Expense	41110	3	165,536	OR	Situs	165,536	
Remove Base Accum. DIT Balance	190	3	(165,536)	OR	Situs	(165,536)	

Description of Adjustment:

This adjustment includes into test period results Bridger Mine reclamation costs which were also included in Dockets UE-374, UE-399, and UE-433. The reclamation costs were originally included in Docket UE-374 to be collected over a five year period from 2021 - 2025. In Docket UE-433 the Company was ordered to extend the depreciable life of the Jim Bridger coal units through 2028. Accordingly, the estimated reclamation costs for the Jim Bridger Mine have been recalibrated to reflect on-going operations through 2028 and the updated reclamation costs are spread through 2028. The adjustment reflects the reclamation costs collected since approval in 2021. The regulatory liability balance is included on a 13-month-average basis for the year ending December 2027.
This adjustment also includes the incremental decommissioning and other plant closure costs for Jim Bridger Units 3 & 4 and Dave Johnston Unit 4, to be recovered over a 12 year period per Order No. 24-447 in Docket UE-433.

PacifiCorp
Oregon General Rate Case - December 2027
Confidential Bridger Mine Reclamation Costs and Decommissioning Cost
Note: Please see Confidential Exhibit PAC/807_CONF for redacted information.

Amount Used in Dockets UE-374, UE-399, UE-433

Annual Incremental Contribution for Reclamation	[redacted]	
Incremental Depreciation Expense Prior to Reclamation		
Years from 2021 to 2025	5	
Annual Incremental Depreciation Expense	[redacted]	
Currently Approved Annual Amount		
Total Amount Collected from January 2021 - March 2027	[redacted]	**See Below**

Proposed Update in Amounts Due to Operating the Bridger Mine Through 2028:

Total Contribution for Reclamation	[redacted]	
Incremental Depreciation Expense Prior to Reclamation		
Less approved amounts collected through March 2027		**See Above**
Net Amount to be collected assuming Operation of Mine through Dec 2028		
Months to End of Depreciable Life (April 2027 to Dec 2028)	21	
Net Monthly Amortization	[redacted]	**See Below**

	TOTAL COMPANY						
	Previous 501 Mthly Accum.	**New 501 Mthly Accum.**	**Net 501 Mthly Accum.**	**SCHMAT Tax**	**41110 Def Inc Tax Exp**	**254 Reg. Liab.**	**190 ADIT**
Jun-25	[redacted]						
Jul-25							
Aug-25							
Sep-25							
Oct-25							
Nov-25							
Dec-25							
Jan-26							
Feb-26							
Mar-26							
Apr-26							
May-26							
Jun-26							
Jul-26							
Aug-26							
Sep-26							
Oct-26							
Nov-26							
Dec-26							
Jan-27							
Feb-27							
Mar-27							
Apr-27							
May-27							
Jun-27							
Jul-27							
Aug-27							
Sep-27							
Oct-27							
Nov-27							
Dec-27							
Annual Total			**Ref 6.4_CONF**	**Ref 6.4_CONF**	**Ref 6.4_CONF**		

13 Mo. Avg. - Total Company	[redacted]
13 Mo. Avg. - Oregon Allocated	
EOP June 2025 Balance	
Adjustment	

*Oregon 2027 SE Factor 26.823%

Ref 6.4_CONF **Ref 6.4_CONF**

PacifiCorp
Oregon General Rate Case - December 2027
Confidential Bridger Mine Reclamation Costs and Decommissioning Cost
Incremental Decommissioning & Other Plant Closure Costs
2018 Depreciation Study
Note: Please see Confidential Exhibit PAC/807_CONF for redacted information.

Plant	Plant Unit Closure Date	Recovery Period (Years)	Incremental Decommissioning Costs	Other Plant Closure Costs	Total Company Annual Amount
Dave Johnston Unit 4	2029	12.00	[redacted]	[redacted]	[redacted]
Jim Bridger Unit 3	2028	12.00			
Jim Bridger Unit 4	2028	12.00			
				Total	**12,974,220**
					Ref 6.4

	407 Mthly Accum.	SCHMAT Tax	41110 Def Inc Tax Exp	254 Reg. Liab.	190 ADIT
Jun-25	1,081,185	1,081,185	(265,827)	(6,487,110)	1,594,962
Jul-25	1,081,185	1,081,185	(265,827)	(7,568,295)	1,860,789
Aug-25	1,081,185	1,081,185	(265,827)	(8,649,480)	2,126,616
Sep-25	1,081,185	1,081,185	(265,827)	(9,730,665)	2,392,443
Oct-25	1,081,185	1,081,185	(265,827)	(10,811,850)	2,658,270
Nov-25	1,081,185	1,081,185	(265,827)	(11,893,035)	2,924,097
Dec-25	1,081,185	1,081,185	(265,827)	(12,974,220)	3,189,924
Jan-26	1,081,185	1,081,185	(265,827)	(14,055,405)	3,455,751
Feb-26	1,081,185	1,081,185	(265,827)	(15,136,590)	3,721,578
Mar-26	1,081,185	1,081,185	(265,827)	(16,217,775)	3,987,405
Apr-26	1,081,185	1,081,185	(265,827)	(17,298,960)	4,253,232
May-26	1,081,185	1,081,185	(265,827)	(18,380,145)	4,519,059
Jun-26	1,081,185	1,081,185	(265,827)	(19,461,330)	4,784,886
Jul-26	1,081,185	1,081,185	(265,827)	(20,542,515)	5,050,713
Aug-26	1,081,185	1,081,185	(265,827)	(21,623,700)	5,316,540
Sep-26	1,081,185	1,081,185	(265,827)	(22,704,885)	5,582,367
Oct-26	1,081,185	1,081,185	(265,827)	(23,786,070)	5,848,194
Nov-26	1,081,185	1,081,185	(265,827)	(24,867,255)	6,114,021
Dec-26	1,081,185	1,081,185	(265,827)	(25,948,440)	6,379,848
Jan-27	1,081,185	1,081,185	(265,827)	(27,029,625)	6,645,675
Feb-27	1,081,185	1,081,185	(265,827)	(28,110,810)	6,911,502
Mar-27	1,081,185	1,081,185	(265,827)	(29,191,995)	7,177,329
Apr-27	1,081,185	1,081,185	(265,827)	(30,273,180)	7,443,156
May-27	1,081,185	1,081,185	(265,827)	(31,354,365)	7,708,983
Jun-27	1,081,185	1,081,185	(265,827)	(32,435,550)	7,974,810
Jul-27	1,081,185	1,081,185	(265,827)	(33,516,735)	8,240,637
Aug-27	1,081,185	1,081,185	(265,827)	(34,597,920)	8,506,464
Sep-27	1,081,185	1,081,185	(265,827)	(35,679,105)	8,772,291
Oct-27	1,081,185	1,081,185	(265,827)	(36,760,290)	9,038,118
Nov-27	1,081,185	1,081,185	(265,827)	(37,841,475)	9,303,945
Dec-27	1,081,185	1,081,185	(265,827)	(38,922,660)	9,569,772
Annual Total	**12,974,220**	**12,974,220**	**(3,189,924)**		
		Ref 6.4	**Ref 6.4**		
		13 Mo. Avg. - Total Company		**(32,435,550)**	**7,974,810**
				Ref 6.4	**Ref 6.4**

Tab 7 - Taxes

PacifiCorp **Page 7.0.1**
Oregon General Rate Case – December 2027
Tax Adjustment Index

The following adjustments were used to arrive at the normalized levels of tax expenses. The Company's 12 months ended June 2025 accrued tax data provided the basis for known and measurable adjustments to the test period.

7.1 Interest True-Up
7.2 Property Tax Expense
7.3 Production Tax Credit
7.4 PowerTax ADIT Adjustment
7.5 Pro Forma Tax Data
7.6 Wyoming Wind Generation Tax
7.7 EDIT Balance Adjustment
7.8 AFUDC - Equity
7.9 Oregon Corporate Activity Tax & Metro SHS

The tax impacts of the following adjustments are included within the adjustment itself:

- Insurance Expense, 4.5
- Bridger Mine Reclamation Costs and Decommissioning Cost, 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
- Pension and Other Post-retirement Plan Balances Removal, page 8.8
- Remove Rolling Hills, page 8.10
- Deer Creek Mine Adjustment, page 8.11
- Emissions Control Equipment Adjustment, page 8.12
- Transmission Project Adjustment, page 8.13
- Cholla Unit 4 Retirement, page 8.14
- Carbon Plant Closure, page 8.16
- Removal of Wildfire Mitigation Capital Rate Base, page 8.17.1
- Dave Johnston Unit 4 Repairs, page 8.18
- Klamath Regulatory Asset, page 8.19
- New Wind Generation Capital Additions, page 8.20
- Remove Large Energy-Use Facilities, page 8.22

The tax impacts of the following adjustment are largely included within adjustment 7.4 and 7.5, though some impacts are included in the adjustment listed below:

- Pro Forma Plant Additions 8.5

PacifiCorp
Oregon General Rate Case - December 2027
Tab 7 Adjustment Summary

		7.2	7.3	7.4	7.5	7.6	7.7
	Total Adjustments	Property Tax Expense	Production Tax Credit	PowerTax ADIT Balance	Pro Forma Tax Balances	Wyoming Wind Generation Tax	EDIT Balance 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 Solar Production	-	-	-	-	-	-	-
13 Wind Production	-	-	-	-	-	-	-
14 Other Renewable Production	-	-	-	-	-	-	-
15 Other Power Supply	-	-	-	-	-	-	-
16 Transmission	-	-	-	-	-	-	-
17 Distribution	-	-	-	-	-	-	-
18 Customer Accounting	-	-	-	-	-	-	-
19 Customer Service & Info	-	-	-	-	-	-	-
20 Sales	-	-	-	-	-	-	-
21 Administrative & General	-	-	-	-	-	-	-
22							
23 Total O&M Expenses	-	-	-	-	-	-	-
24							
25 Depreciation	-	-	-	-	-	-	-
26 Amortization	-	-	-	-	-	-	-
27 Taxes Other Than Income	18,007,436	9,144,779	-	-	-	66,593	-
28 Income Taxes - Federal	(18,471,771)	(1,834,352)	(17,571,263)	7,599,084	1,575,688	(13,358)	(117,983)
29 Income Taxes - State	(8,506,891)	(415,430)	655	1,720,982	336,326	(3,025)	(26,720)
30 Income Taxes - Def Net	5,755,253	-	-	4,515,705	(1,904,243)	-	3,143,791
31 Investment Tax Credit Adj.	-	-	-	-	-	-	-
32 Misc Revenue & Expense	-	-	-	-	-	-	-
33							
34 Total Operating Expenses:	(3,215,973)	6,894,998	(17,570,609)	13,835,771	7,771	50,210	2,999,088
35							
36 Operating Rev For Return:	3,215,973	(6,894,998)	17,570,609	(13,835,771)	(7,771)	(50,210)	(2,999,088)
37							
38 Rate Base:							
39 Electric Plant In Service	-	-	-	-	-	-	-
40 Plant Held for Future Use	-	-	-	-	-	-	-
41 Misc Deferred Debits	-	-	-	-	-	-	-
42 Elec Plant Acq Adj	-	-	-	-	-	-	-
43 Nuclear Fuel	-	-	-	-	-	-	-
44 Prepayments	-	-	-	-	-	-	-
45 Fuel Stock	-	-	-	-	-	-	-
46 Material & Supplies	-	-	-	-	-	-	-
47 Working Capital	(272,197)	209,202	(533,112)	282,781	58,013	1,523	(4,390)
48 Weatherization Loans	-	-	-	-	-	-	-
49 Misc Rate Base	-	-	-	-	-	-	-
50							
51 Total Electric Plant:	(272,197)	209,202	(533,112)	282,781	58,013	1,523	(4,390)
52							
53 Rate Base Deductions:							
54 Accum Prov For Deprec	-	-	-	-	-	-	-
55 Accum Prov For Amort	-	-	-	-	-	-	-
56 Accum Def Income Tax	(64,193,086)	-	-	(56,240,852)	(1,092,760)	-	(6,859,475)
57 Unamortized ITC	14,608	-	-	-	14,608	-	-
58 Customer Adv For Const	-	-	-	-	-	-	-
59 Customer Service Deposits	-	-	-	-	-	-	-
60 Misc Rate Base Deductions	28,621,485	-	-	-	-	-	28,621,485
61							
62 Total Rate Base Deductions	(35,556,993)	-	-	(56,240,852)	(1,078,152)	-	21,762,011
63							
64 Total Rate Base:	(35,829,190)	209,202	(533,112)	(55,958,070)	(1,020,139)	1,523	21,757,620
65							
66 Return on Rate Base	0.107%	-0.129%	0.328%	-0.185%	0.001%	-0.001%	-0.085%
67							
68 Return on Equity	0.214%	-0.257%	0.656%	-0.370%	0.002%	-0.002%	-0.170%
69							
70 TAX CALCULATION:							
71 Operating Revenue	(18,007,436)	(9,144,779)	-	-	-	(66,593)	-
72 Other Deductions	-	-	-	-	-	-	-
73 Interest (AFUDC)	39,948,437	-	-	-	-	-	-
74 Interest	(969,180)	5,659	(14,421)	(1,513,666)	(27,595)	41	588,544
75 Schedule "M" Additions	(78,180,018)	-	-	(77,597,147)	(582,871)	-	-
76 Schedule "M" Deductions	(121,953,913)	-	-	(113,990,577)	(7,963,336)	-	-
77 Income Before Tax	(13,212,799)	(9,150,438)	14,421	37,907,095	7,408,060	(66,634)	(588,544)
78							
79 State Income Taxes	(8,506,891)	(415,430)	655	1,720,982	336,326	(3,025)	(26,720)
80 Taxable Income	(4,705,908)	(8,735,008)	13,766	36,186,113	7,071,734	(63,609)	(561,824)
81							
82 Federal Income Taxes + Other	(18,471,771)	(1,834,352)	(17,571,263)	7,599,084	1,575,688	(13,358)	(117,983)
APPROXIMATE PRICE CHANGE	(8,129,089)	9,485,021	(24,170,798)	13,187,093	(95,115)	69,071	6,372,310

PacifiCorp
Oregon General Rate Case - December 2027
Tab 7 Adjustment Summary

		7.8 AFUDC Equity	7.9 Oregon Corporate Activity Tax & Metro SHS
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	Solar Production	-	-
13	Wind Production	-	-
14	Other Renewable Production	-	-
15	Other Power Supply	-	-
16	Transmission	-	-
17	Distribution	-	-
18	Customer Accounting	-	-
19	Customer Service & Info	-	-
20	Sales	-	-
21	Administrative & General	-	-
22			
23	Total O&M Expenses	-	-
24			
25	Depreciation	-	-
26	Amortization	-	-
27	Taxes Other Than Income	-	8,796,064
28	Income Taxes - Federal	(8,006,688)	(102,899)
29	Income Taxes - State	(1,813,293)	(8,306,386)
30	Income Taxes - Def Net	-	-
31	Investment Tax Credit Adj.	-	-
32	Misc Revenue & Expense	-	-
33			
34	Total Operating Expenses:	(9,819,981)	386,779
35			
36	Operating Rev For Return:	9,819,981	(386,779)
37			
38	Rate Base:		
39	Electric Plant In Service	-	-
40	Plant Held for Future Use	-	-
41	Misc Deferred Debits	-	-
42	Elec Plant Acq Adj	-	-
43	Nuclear Fuel	-	-
44	Prepayments	-	-
45	Fuel Stock	-	-
46	Material & Supplies	-	-
47	Working Capital	(297,949)	11,735
48	Weatherization Loans	-	-
49	Misc Rate Base	-	-
50			
51	Total Electric Plant:	(297,949)	11,735
52			
53	Rate Base Deductions:		
54	Accum Prov For Deprec	-	-
55	Accum Prov For Amort	-	-
56	Accum Def Income Tax	-	-
57	Unamortized ITC	-	-
58	Customer Adv For Const	-	-
59	Customer Service Deposits	-	-
60	Misc Rate Base Deductions	-	-
61			
62	Total Rate Base Deductions	-	-
63			
64	Total Rate Base:	(297,949)	11,735
65			
66	Return on Rate Base	0.185%	-0.007%
67			
68	Return on Equity	0.369%	-0.015%
69			
70	TAX CALCULATION:		
71	Operating Revenue	-	(8,796,064)
72	Other Deductions	-	-
73	Interest (AFUDC)	39,948,437	-
74	Interest	(8,060)	317
75	Schedule "M" Additions	-	-
76	Schedule "M" Deductions	-	-
77	Income Before Tax	(39,940,377)	(8,796,381)
78			
79	State Income Taxes	(1,813,293)	(8,306,386)
80	Taxable Income	(38,127,084)	(489,996)
81			
82	Federal Income Taxes + Other	(8,006,688)	(102,899)
	APPROXIMATE PRICE CHANGE	(13,508,740)	532,068

PacifiCorp PAGE 7.1
Oregon General Rate Case - December 2027
Interest True-Up

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Interest	427	3	(476,385)	OR	Situs	(476,385)	Below
Adjustment Detail:			**Total Company**				
Interest June 2025 - Unadjusted			574,803,750			165,097,382	2.15
Interest December 2027 - Normalized			596,248,378			164,620,998	Below
Adjustment:			21,444,628			(476,385)	
Normalized Rate Base			24,024,831,598			6,085,803,981	2.2
Other & Non-Regulated						-	
Adjusted Rate Base			24,024,831,598			6,085,803,981	2.2
Weighted Cost of Debt			2.705%			2.705%	2.1
Normalized Interest			649,871,695			164,620,998	2.15
						-	

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.

PacifiCorp PAGE 7.2
Oregon General Rate Case - December 2027
Property Tax Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	408	3	32,742,298	GPS	27.9296%	9,144,779	7.2.1

Description of Adjustment:

This adjustment normalizes the difference between actual accrued property tax expense and forecasted property tax expense resulting from estimated capital additions.

PacifiCorp
Oregon General Rate Case - December 2027
Property Tax Expense

FERC Account	G/L Account	Co. Code	Total	Ref
408.15	579000	1000	152,360,699	
Total Accrued Property Tax - 12 Months End. June 2025			152,360,699	
Estimated Property Tax Expense for 12 Months Ending December 31, 2027			185,102,997	
Incremental Adjustment to Property Taxes			**32,742,298**	**Ref. 7.2**

* Includes Idaho Kwh Tax

PacifiCorp PAGE 7.3
Oregon General Rate Case - December 2027
Production Tax Credit

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Production Tax Credit	40910	1	228,634,999	SG	27.756%	63,458,958	7.3.1
Production Tax Credit	40910	3	(81,033,112)	OR	Situs	(81,033,112)	7.3.1

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 Production Tax credits and adds in the pro forma period Production Tax credits which are reflected in the company's Transition Adjustment Mechanism filings annually.

As described in the testimony of Shelley E. McCoy, 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.

PacifiCorp
Oregon General Rate Case - December 2027
Production Tax Credit

		Calendar Year 2027												
	In-Service	Facilities Placed In-Service prior to 2022												
Facility Name	**Date ***	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
Cedar Springs	**12/8/2020**	52,745,000	47,885,012	51,778,324	51,625,277	51,851,742	50,133,914	50,637,523	51,625,676	51,245,242	51,842,863	51,189,805	53,358,363	**615,918,742**
Dunlap	**9/7/2020**	37,162,414	35,039,738	37,275,051	36,243,305	36,642,707	38,018,520	32,114,320	33,393,059	28,392,824	33,027,020	36,521,613	41,579,688	**425,410,258**
Ekola Flats	**VARIOUS ****	66,528,641	61,332,547	66,225,578	63,772,141	65,810,102	68,360,789	59,674,719	60,495,516	51,312,383	59,377,859	63,371,367	74,095,016	**760,356,656**
Foote Creek	**3/24/2021**	18,279,933	15,773,916	16,530,964	18,474,242	17,292,018	17,497,041	9,334,654	14,197,981	11,840,526	12,867,489	13,472,383	18,112,412	**183,673,558**
Glenrock I	**9/27/2019**	23,321,910	20,486,467	22,377,297	22,712,653	22,108,215	22,413,895	22,573,952	22,500,250	21,935,927	22,647,049	22,857,538	24,026,544	**269,961,695**
Glenrock III	**9/24/2019**	7,860,587	6,789,337	7,547,957	7,583,388	7,439,814	7,620,969	7,389,508	7,378,392	7,245,759	7,451,453	7,911,121	8,369,891	**90,588,178**
Goodnoe Hills	**12/20/2019**	19,195,830	20,022,961	22,534,412	0	0	0	0	0	0	0	0	0	**61,753,203**
High Plains	**12/19/2019**	26,703,727	26,002,496	29,492,006	30,657,471	30,192,436	31,259,352	27,673,924	19,442,426	25,905,959	27,252,527	26,184,098	32,060,771	**332,827,191**
Leaning Juniper	**9/13/2019**	14,752,951	20,074,750	22,505,588	25,694,533	27,921,037	26,576,615	25,947,539	25,694,633	24,521,152	22,254,088	18,566,354	15,841,608	**270,350,849**
Marengo I	**1/27/2020**	32,415,008	34,512,316	36,860,539	0	0	0	0	0	0	0	0	0	**103,787,863**
Marengo II	**2/25/2020**	16,546,574	17,075,932	18,790,781	0	0	0	0	0	0	0	0	0	**52,413,287**
McFadden Ridge	**11/7/2019**	8,045,509	7,804,519	9,005,327	9,591,364	9,456,228	9,515,595	8,448,991	5,958,106	7,803,700	7,983,265	7,893,379	9,968,877	**101,474,860**
Pryor Mountain	**VARIOUS ****	79,175,664	73,555,313	62,661,168	79,388,125	62,440,336	60,597,422	31,850,584	52,372,535	46,291,445	81,777,156	89,517,523	93,216,180	**812,843,451**
Rolling Hills	**10/17/2019**	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Seven Mile Hill I	**9/9/2019**	33,280,957	31,114,682	32,827,645	32,172,607	32,624,514	34,183,109	28,540,932	31,069,506	24,665,033	30,654,395	31,965,256	36,611,320	**379,709,955**
Seven Mile Hill II	**9/9/2019**	7,123,785	6,575,556	7,123,658	6,922,263	6,821,481	7,268,306	5,825,271	6,474,355	4,662,584	6,484,892	6,731,192	8,109,196	**80,122,541**
TB Flats	**VARIOUS ****	159,353,957	152,647,367	169,955,805	148,934,047	149,264,043	159,471,891	81,273,512	111,554,070	75,922,793	91,935,822	155,102,441	236,865,867	**1,692,281,615**
Total Credit Eligible Production (KWh)		**602,492,448**	**576,692,908**	**613,492,098**	**533,771,416**	**519,864,672**	**532,917,418**	**391,285,430**	**442,156,504**	**381,745,327**	**455,555,878**	**531,284,071**	**652,215,734**	**6,233,473,904**
Credit Rate Per KWh		0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031
Renewable Electricity Production Tax Credit		**18,677,266**	**17,877,480**	**19,018,255**	**16,546,914**	**16,115,805**	**16,520,440**	**12,129,848**	**13,706,852**	**11,834,105**	**14,122,232**	**16,469,806**	**20,218,688**	**193,237,691**

	In-Service	Facilities Placed In-Service after 2022 and before 2025												
Facility Name	**Date ***	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
Foote Creek II-IV	**11/21/2023**	16,591,802	17,562,573	16,715,792	15,006,692	14,623,463	15,111,217	8,860,864	12,582,979	10,747,282	13,041,353	16,034,987	19,948,599	**176,827,602**
Rock Creek I - 2024 Turbines	**VARIOUS ****	24,057,045	19,734,852	21,345,781	18,618,189	13,438,663	11,666,079	10,013,708	9,840,472	12,142,319	19,454,037	23,269,975	25,958,277	**209,539,397**
Rock River I	**9/23/2024**	19,973,883	20,593,042	13,726,285	21,182,969	14,862,516	13,423,252	10,706,716	12,521,732	18,456,879	24,224,932	22,106,633	17,975,493	**209,754,332**
Total Credit Eligible Production (KWh)		**60,622,730**	**57,890,466**	**51,787,859**	**54,807,851**	**42,924,642**	**40,200,548**	**29,581,288**	**34,945,182**	**41,346,480**	**56,720,321**	**61,411,595**	**63,882,369**	**596,121,332**
Credit Rate Per KWh		0.0325	0.0325	0.0325	0.0325	0.0325	0.0325	0.0325	0.0325	0.0325	0.0325	0.0325	0.0325	0.0325
Renewable Electricity Production Tax Credit - Wind PIS from 2022 through 2024		**1,970,239**	**1,881,440**	**1,683,105**	**1,781,255**	**1,395,051**	**1,306,518**	**961,392**	**1,135,718**	**1,343,761**	**1,843,410**	1,995,877	2,076,177	19,373,943
Bonus Credit		110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%
Total Renewable Electricity Production Tax Credit - Wind PIS from 2022 through 2024, including Bonus		2,167,263	2,069,584	1,851,416	1,959,381	1,534,556	1,437,170	1,057,531	1,249,290	1,478,137	2,027,751	**2,195,465**	**2,283,795**	**21,311,337**

	In-Service	Facilities Placed In-Service after 2025												
Facility Name	**Date ***	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
Rock Creek I - 2025 Turbines	**VARIOUS ****	43,942,543	45,304,692	30,197,828	46,602,531	32,697,535	29,531,154	23,554,776	27,547,811	40,605,133	53,294,850	48,634,593	39,546,085	**461,459,531**
Rock Creek II	**VARIOUS ****	127,925,688	133,146,203	85,395,305	133,007,672	93,736,125	83,404,906	69,501,742	80,241,297	122,417,461	156,504,984	149,178,875	113,187,719	**1,347,647,977**
Total Credit Eligible Production (KWh)		**171,868,230**	**178,450,896**	**115,593,133**	**179,610,203**	**126,433,660**	**112,936,061**	**93,056,518**	**107,789,108**	**163,022,594**	**209,799,834**	**197,813,468**	**152,733,804**	**1,809,107,508**
Credit Rate Per KWh		0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310
Renewable Electricity Production Tax Credit - Wind PIS from 2022 through 2024		**5,327,915**	**5,531,978**	**3,583,387**	**5,567,916**	**3,919,443**	**3,501,018**	**2,884,752**	**3,341,462**	**5,053,700**	**6,503,795**	6,132,218	4,734,748	56,082,333
Bonus Credit		110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%
Total Renewable Electricity Production Tax Credit - Wind PIS from 2022 through 2024, including Bonus		5,860,707	6,085,176	3,941,726	6,124,708	4,311,387	3,851,120	3,173,227	3,675,608	5,559,070	7,154,175	**6,745,440**	**5,208,223**	**61,690,566**
Total Federal Production Tax Credit		**26,705,235**	**26,032,240**	**24,811,396**	**24,631,002**	**21,961,748**	**21,808,730**	**16,360,606**	**18,631,750**	**18,871,312**	**23,304,158**	**25,410,711**	**27,710,706**	**276,239,595**

* In-Service dates in **bold** reflect actual in-service dates.

CY2027 SG Factor from docket UE 469 29.334%

** Ekola Flats, Pryor Mountain, Rock Creek I & II, and TB Flats were placed in service using circuits, which results in multiple placed in-service dates.

Oregon-allocated forecated PTC **81,033,112**

Ref. 7.3

PacifiCorp PAGE 7.4
Oregon General Rate Case - December 2027
PowerTax ADIT Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
ADIT - California	282	3	(32,829,551)	CA	Situs	-	7.4.2
ADIT - Idaho	282	3	(35,931,086)	ID	Situs	-	7.4.2
ADIT - Oregon	282	3	(105,041,293)	OR	Situs	(105,041,293)	7.4.2
ADIT - Other	282	3	736,452	OTHER	Situs	-	7.4.2
ADIT - Utah	282	3	(350,566,998)	UT	Situs	-	7.4.2
ADIT - Washington	282	3	(32,069,621)	WA	Situs	-	7.4.2
ADIT - Wyoming	282	3	(71,442,745)	WYP	Situs	-	7.4.2
ADIT - SG	282	3	(2,701,234,541)	SG	27.756%	(749,743,170)	7.4.2
ADIT - SO	282	3	(118,713,514)	SO	27.909%	(33,131,626)	7.4.2
ADIT - DITBAL	282	1	3,134,532,770	DITBAL	25.779%	808,051,722	7.4.2
ADIT - Accelerated Pollution Control Facilities	281	1	104,695,016	SG	27.756%	29,058,703	7.4.2
			(207,865,111)			(50,805,663)	7.4.2
ADIT - Other Property Flowthrough	282	3	(2,319,643)	OR	Situs	(2,319,643)	7.4.2
Schedule M Adjustment - Permanent	SCHMAP	3	(8,436)	SCHMDEXP	27.246%	(2,298)	7.4.2
Schedule M Adjustment	SCHMAT	3	(144,250,129)	CIAC	25.578%	(36,896,428)	7.4.2
Schedule M Adjustment	SCHMAT	3	36,941,425	SCHMDEXP	27.246%	10,065,148	7.4.2
Schedule M Adjustment	SCHMAT	3	(1,423,321)	SG	27.756%	(395,051)	7.4.2
Schedule M Adjustment	SCHMAT	3	(976,996)	SO	27.909%	(272,669)	7.4.2
Schedule M Adjustment	SCHMAT	3	(196,056,661)	SNP	26.557%	(52,065,894)	7.4.2
Schedule M Adjustment	SCHMAT	3	(3,742,834)	SNPD	25.578%	(957,345)	7.4.2
Schedule M Adjustment	SCHMDT	3	(85,921,228)	GPS	27.930%	(23,997,420)	7.4.2
Schedule M Adjustment	SCHMDT	3	(137,048,901)	SG	27.756%	(38,038,710)	7.4.2
Schedule M Adjustment	SCHMDT	3	(11,730,114)	SO	27.909%	(3,273,745)	7.4.2
Schedule M Adjustment	SCHMDT	3	(252,660,839)	SNP	26.557%	(67,098,013)	7.4.2
Schedule M Adjustment	SCHMDT	3	6,797,236	TAXDEPR	27.710%	1,883,512	7.4.2
Deferred Income Tax Expense	41110	3	35,466,202	CIAC	25.578%	9,071,577	7.4.2
Deferred Income Tax Expense	41110	3	(9,082,640)	SCHMDEXP	27.246%	(2,474,678)	7.4.2
Deferred Income Tax Expense	41110	3	349,946	SG	27.756%	97,130	7.4.2
Deferred Income Tax Expense	41110	3	240,210	SO	27.909%	67,040	7.4.2
Deferred Income Tax Expense	41110	3	48,203,667	SNP	26.557%	12,801,233	7.4.2
Deferred Income Tax Expense	41110	3	920,236	SNPD	25.578%	235,379	7.4.2
Deferred Income Tax Expense	41010	3	(21,125,109)	GPS	27.930%	(5,900,150)	7.4.2
Deferred Income Tax Expense	41010	3	(33,695,665)	SG	27.756%	(9,352,425)	7.4.2
Deferred Income Tax Expense	41010	3	(2,884,036)	SO	27.909%	(804,902)	7.4.2
Deferred Income Tax Expense	41010	3	(62,120,710)	SNP	26.557%	(16,497,120)	7.4.2
Deferred Income Tax Expense	41010	3	1,671,209	TAXDEPR	27.710%	463,092	7.4.2
Deferred Income Tax Expense - Flowthrough	41110	3	403,351	CA	Situs	-	7.4.2
Deferred Income Tax Expense - Flowthrough	41110	3	(46,800)	ID	Situs	-	7.4.2
Deferred Income Tax Expense - Flowthrough	41110	3	1,218,156	OR	Situs	1,218,156	7.4.2
Deferred Income Tax Expense - Flowthrough	41110	3	13,991	OTHER	0.000%	-	7.4.2
Deferred Income Tax Expense - Flowthrough	41110	3	(309,023)	UT	Situs	-	7.4.2
Deferred Income Tax Expense - Flowthrough	41110	3	(47,016)	WA	Situs	-	7.4.2
Deferred Income Tax Expense - Flowthrough	41110	3	(326,956)	WYP	Situs	-	7.4.2
Deferred Income Tax Expense - Flowthrough	41110	3	39,584,572	SG	27.756%	10,986,926	7.4.2
Deferred Income Tax Expense - Flowthrough	41110	3	3,300,391	SO	27.909%	921,103	7.4.2
Deferred Income Tax Expense - Other Flowthrough	41110	3	337,994	OR	100.000%	337,994	7.4.2

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, 2027, with asset additions through March 31, 2027. Updates the property related schedule m-items and associated deferred income tax expense for the 12 months ended December 31, 2027.

PacifiCorp PAGE 7.4.1
Oregon General Rate Case - December 2027
PowerTax ADIT Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	3,483,017	OR	Situs	3,483,017	
Schedule M Adjustment	SCHMAT	3	(22,946)	SG	27.756%	(6,369)	
Schedule M Adjustment	SCHMAT	3	(1,968,037)	SO	27.909%	(549,257)	
Schedule M Adjustment	SCHMDT	3	18,653,796	OR	Situs	18,653,796	
Schedule M Adjustment	SCHMDT	3	(110,952)	SG	27.756%	(30,795)	
Schedule M Adjustment	SCHMDT	3	(7,485,792)	SO	27.909%	(2,089,202)	
Deferred Income Tax Expense	41110	3	(856,356)	OR	Situs	(856,356)	
Deferred Income Tax Expense	41110	3	5,642	SG	27.756%	1,566	
Deferred Income Tax Expense	41110	3	483,873	SO	27.909%	135,044	
Deferred Income Tax Expense	41010	3	4,586,334	OR	Situs	4,586,334	
Deferred Income Tax Expense	41010	3	(27,279)	SG	27.756%	(7,571)	
Deferred Income Tax Expense	41010	3	(1,840,502)	SO	27.909%	(513,664)	
ADIT - SG	282	3	(3,528,325)	OR	Situs	(3,528,325)	
ADIT - SO	282	3	48,636	SG	27.756%	13,499	
ADIT - SO	282	3	1,430,656	SO	27.909%	399,280	

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, 2027, with asset additions through March 31, 2027. Updates the property related schedule m-items and associated deferred income tax expense for the 12 months ended December 31, 2027.

PacifiCorp PAGE 7.4.2
Oregon General Rate Case - December 2027
PowerTax Adjustment for Year Ending December 2027

Book Tax Difference		Total Company			STATE Allocation
Description - ADIT	M-Item	June 2025 Base Period	Adjusted Utility	Adjustment	2020 Protocol
Accumulated Deferred Income Taxes (CA)	- - - - -	0	(32,829,551)	(32,829,551)	CA
Accumulated Deferred Income Taxes (IDU)	- - - - -	0	(35,931,086)	(35,931,086)	ID
Accumulated Deferred Income Taxes (OR)	- - - - -	0	(105,041,293)	(105,041,293)	OR
Accumulated Deferred Income Taxes (OTHER)	- - - - -	0	736,452	736,452	OTHER
Accumulated Deferred Income Taxes (SG)	- - - - -	0	(2,701,234,541)	(2,701,234,541)	SG
Accumulated Deferred Income Taxes (SO)	- - - - -	0	(118,713,514)	(118,713,514)	SO
Accumulated Deferred Income Taxes (UT)	- - - - -	0	(350,566,998)	(350,566,998)	UT
Accumulated Deferred Income Taxes (WA)	- - - - -	0	(32,069,621)	(32,069,621)	WA
Accumulated Deferred Income Taxes (WY)	- - - - -	0	(71,442,745)	(71,442,745)	WYP
Accumulated Deferred Income Taxes (DITBAL)	- - - - -	(3,134,532,770)	0	3,134,532,770	DITBAL
Accelerated Pollution Control Facilities ADIT (SG) - FERC 281	- - - - -	(104,695,016)	0	104,695,016	SG
Total		(3,239,227,786)	(3,447,092,897)	(207,865,111)	
				Ref. 7.4	

ADIT - Other Property Flowthrough - OR	105.272	11,771,262	9,451,620	(2,319,643)	OR
				Ref. 7.4	

Book Tax Difference		Total Company			STATE Allocation	
Description - Schedule M Items	M-Item	June 2025 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	142,812	134,376	(8,436)	SCHMDEXP	Ref 7.4
Schedule M Additions - Temporary:						
Capitalized Labor & Benefits Costs	105.100	1,525,414	548,418	(976,996)	SO	Ref 7.4
Book Depreciation	105.120	1,188,372,461	1,225,313,886	36,941,425	SCHMDEXP	Ref 7.4
CIAC	105.130	182,025,168	37,775,039	(144,250,129)	CIAC	Ref 7.4
Reimbursements	105.140	3,742,834	0	(3,742,834)	SNPD	Ref 7.4
Avoided Costs	105.142	207,194,161	11,137,500	(196,056,661)	SNP	Ref 7.4
Capitalization of Test Energy	105.146	1,423,321	0	(1,423,321)	SG	Ref 7.4
Total Schedule M Additions		**1,584,283,359**	**1,274,774,842**	**(309,508,517)**		
Schedule M Deductions - Temporary:						
Repair Deduction	105.122	185,350,545	48,301,644	(137,048,901)	SG	Ref 7.4
Tax Depreciation	105.125	1,445,349,992	1,452,147,228	6,797,236	TAXDEPR	Ref 7.4
Book Capitalized Depreciation	105.137	11,730,114	0	(11,730,114)	SO	Ref 7.4
AFUDC - Debt	105.141 - Debt	106,927,281	4,793,156	(102,134,125)	SNP	Ref 7.4
AFUDC - Equity	105.141 - Equity	160,902,613	10,642,281	(150,260,332)	SNP	Ref 7.4
Basis Intangible Difference	105.143	266,382	0	(266,382)	SNP	Ref 7.4
Tax Gain / (Loss) on Prop. Disposition	105.152	10,616,931	400,876	(10,216,055)	GPS	Ref 7.4
Removal Costs	105.175	86,325,133	16,673,740	(69,651,393)	GPS	Ref 7.4
Book Gain/Loss on Prop. Disposition	105.470	6,053,780	0	(6,053,780)	GPS	Ref 7.4
Total Schedule M Deductions		**2,013,522,771**	**1,532,958,925**	**(480,563,846)**		

Book Tax Difference		Total Company			STATE Allocation	
Description - Deferred Income Tax Expense	M-Item	June 2025 Base Period	Adjusted Utility	Adjustment	2020 Protocol	
		Per Tax Model	Per PowerTax			
Flow-through:						
California	105.115	(533,420)	(130,069)	403,351	CA	Ref 7.4
Idaho	105.115	16,593	(30,207)	(46,800)	ID	Ref 7.4
OTHER	105.115	(14,065)	(74)	13,991	OTHER	Ref 7.4
Oregon	105.115	(2,497,166)	(1,279,010)	1,218,156	OR	Ref 7.4
SG	105.115	(33,674,115)	5,910,457	39,584,572	SG	Ref 7.4
SO	105.115	(2,588,777)	711,614	3,300,391	SO	Ref 7.4
Utah	105.115	(1,971,679)	(2,280,702)	(309,023)	UT	Ref 7.4
Washington	105.115	37,973	(9,043)	(47,016)	WA	Ref 7.4
Wyoming - P	105.115	310,082	(16,874)	(326,956)	WYP	Ref 7.4
Total		**(40,914,574)**	**2,876,093**	**43,790,667**		
Other Property Flowthrough - Oregon	105.272	924,436	1,262,430	337,994		
Total		**924,436**	**1,262,430**	**337,994**	OR	Ref 7.4

PacifiCorp PAGE 7.5
Oregon General Rate Case - December 2027
Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Schedule M Adjustment Permanent	SCHMAP	3	(20,572)	SE	26.823%	(5,518)	
	SCHMAP	3	562,627	SO	27.909%	157,023	
	SCHMDP	3	1,996,877	SE	26.823%	535,618	
	SCHMDP	3	(79,071)	SNP	26.557%	(20,999)	
Schedule M Adjustment Temporary	SCHMAT	3	5,196,660	BADDEBT	42.721%	2,220,046	
	SCHMAT	3	434,464	CA	0.000%	-	
	SCHMAT	3	2,062,025	GPS	27.930%	575,914	
	SCHMAT	3	(51,336)	IDU	0.000%	-	
	SCHMAT	3	-	OR	100.000%	-	
	SCHMAT	3	49,637,341	OTHER	0.000%	-	
	SCHMAT	3	(6,828,338)	SE	26.823%	(1,831,551)	
	SCHMAT	3	(189,105)	SG	27.756%	(52,487)	
	SCHMAT	3	(281,670)	SNP	26.557%	(74,802)	
	SCHMAT	3	(5,434,191)	SO	27.909%	(1,516,622)	
	SCHMAT	3	(198,900)	TROJD	27.589%	(54,874)	
	SCHMAT	3	-	UT	0.000%	-	
	SCHMAT	3	(4,237,311)	WA	0.000%	-	
	SCHMAT	3	692,746	WYP	0.000%	-	
	SCHMDT	3	5,295,531	CA	0.000%	-	
	SCHMDT	3	5,997,416	IDU	0.000%	-	
	SCHMDT	3	(641,292)	OR	100.000%	(641,292)	
	SCHMDT	3	(318,193,810)	OTHER	0.000%	-	
	SCHMDT	3	488,164	SE	26.823%	130,939	
	SCHMDT	3	(4,142,283)	SG	27.756%	(1,149,714)	
	SCHMDT	3	(37,979)	SNPD	25.578%	(9,714)	
	SCHMDT	3	(24,394,283)	SO	27.909%	(6,808,174)	
	SCHMDT	3	34,046,645	UT	0.000%	-	
	SCHMDT	3	255,136	WA	0.000%	-	
	SCHMDT	3	-	WYP	0.000%	-	
Current Federal Tax Credits	40910	3	18,359	SE	26.823%	4,924	
	40910	3	310,222	SG	27.756%	86,104	
	40910	3	(1,449)	SO	27.909%	(404)	

Description of Adjustment:

This adjustment normalizes the Base period Schedule M to an estimated pro forma level of expense for the December 2027 Test period.

PacifiCorp PAGE 7.5.1
Oregon General Rate Case - December 2027
Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Deferred Tax Expense Debit	41010	3	1,301,991	CA	0.000%	-	
	41010	3	1,474,560	IDU	0.000%	-	
	41010	3	(157,672)	OR	100.000%	(157,672)	
	41010	3	(78,233,038)	OTHER	0.000%	-	
	41010	3	120,022	SE	26.823%	32,193	
	41010	3	(1,018,446)	SG	27.756%	(282,676)	
	41010	3	(9,337)	SNPD	25.578%	(2,388)	
	41010	3	(5,997,725)	SO	27.909%	(1,673,899)	
	41010	3	8,370,912	UT	0.000%	-	
	41010	3	62,729	WA	0.000%	-	
	41010	3	-	WYP	0.000%	-	
Deferred Tax Expense Credit	41110	3	(1,277,682)	BADDEBT	42.721%	(545,834)	
	41110	3	(106,820)	CA	0.000%	-	
	41110	3	12,622	IDU	0.000%	-	
	41110	3	-	FERC	0.000%	-	
	41110	3	(506,982)	GPS	27.930%	(141,598)	
	41110	3	-	OR	100.000%	-	
	41110	3	(12,206,408)	OTHER	0.000%	-	
	41110	3	1,678,858	SE	26.823%	450,316	
	41110	3	45,196	SG	27.756%	12,544	
	41110	3	69,253	SNP	26.557%	18,391	
	41110	3	1,336,082	SO	27.909%	372,886	
	41110	3	48,903	TROJD	27.589%	13,492	
	41110	3	-	UT	0.000%	-	
	41110	3	1,041,810	WA	0.000%	-	
	41110	3	(170,323)	WYP	0.000%	-	
	41110	3	-	WYU	0.000%	-	
ITC Amortization	41140	3	362,975	DGU	0.000%	-	

Description of Adjustment:

This adjustment normalizes the Base period Deferred Income Tax Expense to a pro forma level of expense for the December 2027 Test period.

PacifiCorp PAGE 7.5.2
Oregon General Rate Case - December 2027
Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
ADIT Balance 190	190	3	(90,076)	BADDEBT	42.721%	(38,481)	
	190	3	(44,357)	CA	0.000%	-	
	190	3	2,904	IDU	0.000%	-	
	190	3	276	OR	100.000%	276	
	190	3	(3,042,578)	OTHER	0.000%	-	
	190	3	756,406	SE	26.823%	202,889	
	190	3	558,672	SG	27.756%	155,063	
	190	3	(15,181,977)	SO	27.909%	(4,237,121)	
	190	3	5,967	TROJD	27.589%	1,646	
	190	3	84,823	UT	0.000%	-	
	190	3	1,419,565	WA	0.000%	-	
	190	3	-	WYP	0.000%	-	
	190	3	2,482,860	SNPD	25.578%	635,068	
ADIT Balance 282	282	3	58,297	OTHER	0.000%	-	
	282	3	(6,403)	SE	26.823%	(1,717)	
	282	3	-	SO	27.909%	-	
	282	3	-	SNP	26.557%	-	
	282	3	-	UT	0.000%	-	
	282	3	-	WYP	0.000%	-	
	282	3	97,145	IDU	0.000%	-	
ADIT Balance 283	283	3	3,249,338	CA	0.000%	-	
	283	3	(152,385)	GPS	27.930%	(42,560)	
	283	3	461,909	IDU	0.000%	-	
	283	3	-	OR	100.000%	-	
	283	3	170,016,144	OTHER	0.000%	-	
	283	3	-	SE	26.823%	-	
	283	3	461,396	SG	27.756%	128,063	
	283	3	10,358	SNP	26.557%	2,751	
	283	3	7,529,373	SO	27.909%	2,101,365	
	283	3	373,699	UT	0.000%	-	
	283	3	94,725	WA	0.000%	-	
	283	3	-	WYP	0.000%	-	
	283	3	-	WYU	0.000%	-	
ADIT Balance 255	255	3	1,318,519	UT	0.000%	-	
	255	3	52,631	SG	27.756%	14,608	
	255	3	12,464	IDU	0.000%	-	

Description of Adjustment:

This adjustment normalizes the Base period Accumulated Deferred Income Tax Balances to a pro forma level of a thirteen-month average rate base balance for the December 2027 Test period.

PacifiCorp PAGE 7.6
Oregon General Rate Case - December 2027
Wyoming Wind Generation Tax

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	408	3	239,926	SG	27.756%	66,593	7.6.1

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 priviledge 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.

PacifiCorp
Oregon General Rate Case - December 2027
Wyoming Wind Generation Tax

Wind Plant	December 2027 NPC MWH Production (b)	Tax Begins	2027 $1/MWH Tax	
Glenrock I (b)	293,437	1/1/2012	293,437	
Glenrock III (b)	110,473	1/1/2012	110,473	
Seven Mile Hill	379,710	1/1/2012	379,710	
Seven Mile Hill II	80,123	1/1/2012	80,123	
Rolling Hills (b)	-	1/17/2012	-	
High Plains	332,827	9/1/2012	332,827	
McFadden Ridge	101,475	9/1/2012	101,475	
Dunlap	425,410	10/1/2013	425,410	
Cedar Springs Wind II	615,919	12/8/2023	615,919	
Ekola Flats Wind	760,357	VARIOUS	760,357	
TB Flats Wind	1,692,282	VARIOUS	1,692,282	
Foote Creek	183,674	3/24/2024	183,674	
Foote Creek II-IV	176,828	11/21/2026	176,828	
Rock Creek I (a)	527	VARIOUS	527	
Rock Creek II (a)	-	VARIOUS	-	
Rock River I (a)	71,515	9/23/2027	71,515	
Total Wyoming Wind MWH	5,224,555		5,224,557	
June 2025 Results of Operations Wind Tax			4,984,631	
Adjustment to normalize to December 2027			**239,926**	**Ref. 7.6**

(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. In addition, Rolling Hills generation is excluded as this facility is not included in Oregon rates.

PacifiCorp PAGE 7.7
Oregon General Rate Case - December 2027
EDIT Balance Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Reg. Liabilities - Non-Protected EDIT	254	1	1,785	OR	100.00%	1,785	
Other Reg. Liabilities - Protected EDIT	254	3	28,619,700	OR	100.00%	28,619,700	7.7.1
Adjustment to Tax:							
ADIT Bal - Non-Protected EDIT	190	1	(439)	OR	100.00%	(439)	
ADIT Bal - Protected EDIT	190	3	(7,036,612)	OR	100.00%	(7,036,612)	7.7.1
ADIT Bal - Protected EDIT - PMI	282	3	662,034	SE	26.82%	177,576	7.7.1
EDIT Amortization	41110	3	3,143,791	OR	100.00%	3,143,791	7.7.1

Description of Adjustment:

Protected PP&E EDIT: This adjustment reflects the level of protected property EDIT amortization and adjusts the rate base for the test period.

PacifiCorp Page 7.7.1
Oregon General Rate Case - December 2027
EDIT Balance Adjustment

Description	Account	June 2025 Booked Allocation - Year End	December 2027 Correct Allocation - 13 Month Avg.	Adjustment	Ref
EDIT Reg Liabilities	254OR	(1,785)	-	**1,785**	**Page 7.7**
	Total	**(1,785)**	**-**	**1,785**	
Protected EDIT Reg Liabilities	254OR	(307,899,169)	(279,279,469)	**28,619,700**	**Page 7.7**
Grand Total		**(307,900,954)**	**(279,279,469)**	**28,621,485**	
DTA - EDIT Balances	190OR	439	-	**(439)**	**Page 7.7**
	Total	**439**	**-**	**(439)**	
DTA - Protected EDIT Balances	190OR	75,701,937	68,665,325	**(7,036,612)**	**Page 7.7**
DTL - Protected EDIT Balances - PMI	282SE	(935,763)	(273,730)	**662,034**	**Page 7.7**
Grand Total		**75,702,376**	**68,665,325**	**(7,037,051)**	

	Oregon		
Protected EDIT Amortization	**June 30, 2025**	**December 31, 2027**	**Adjustment**
Protected EDIT - RSGM	(13,341,597)	(10,198,056)	3,143,541
Protected EDIT - PMI	(66,766)	(66,516)	250
Total Protected EDIT Amortization	(13,408,363)	(10,264,572)	3,143,791
Grand Total EDIT Amortization	(13,408,363)	(10,264,572)	3,143,791 **Page 7.7**

NOTE: The EDIT amortization related to credits to customers via Sch 197 are removed as these are not included in base rates. The Protected EDIT Amortization is adjusted to the proforma December 2027 level of amortization.

PacifiCorp PAGE 7.8
Oregon General Rate Case - December 2027
AFUDC - Equity

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
AFUDC - Equity	419	1	150,427,787	SNP	26.557%	39,948,437	7.8.1

Description of Adjustment:

This adjustment brings in the appropriate level of AFUDC - Equity into results to align the tax schedule m with regulatory income.

PacifiCorp PAGE 7.8.1
Oregon General Rate Case - December 2027
AFUDC Equity for 12 Months Ended December 31, 2027

			Equity SAP Accts 382000 & 382060	
Jun-25	12 months	Account 419	(161,070,067)	
Dec-27	12 months	AFUDC-Equity SCHMDT	(10,642,281)	
Dec-27	12 months	AFUDC-Intangible Basis - Equity	-	
		Total	(10,642,281)	
Adjustment to Account 419			150,427,787	**Ref. 7.8**

PacifiCorp PAGE 7.9
Oregon General Rate Case - December 2027
Oregon Corporate Activity Tax & Metro SHS

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
OCAT - Remove Base Period	40911	1	(8,372,798)	OR	100.00%	(8,372,798)	7.9.1
OCAT - Test Period	408	3	8,796,064	OR	100.00%	8,796,064	7.9.1
Metro SHS Tax - Remove Base Period	40911	1	(27,016)	OR	100.00%	(27,016)	7.9.2
Metro SHS Tax - Test Period	40911	3	492,784	OR	100.00%	492,784	7.9.2

Description of Adjustment:

This adjustment is to adjust the the Oregon Corporate Activity Tax and Metro Business Income Tax/Metro Supportive Housing Services tax amount for the test period. Although included in Account 40911 in the base period, the Oregon Corporate Activity Tax will be included in Account 408 for purposes of the general rate case.

PacifiCorp PAGE 7.9.1
Oregon General Rate Case - December 2027
Oregon Corporate Activity Tax & Metro SHS

			OR CAT	
Jun-25	12 months	Oregon Corporate Activity Tax - Base Period - Account 409	8,372,798	
		Adjustment to Account 40911	8,372,798	**Ref. 7.9**
Dec-27	12 months	Oregon Corporate Activity Tax - 2027 Forecast - Account 408	7,884,472	
		Adjustment to Account 408	7,884,472	**Ref. 7.9**

Note: The OCAT included in the base period is charged to Account 40911. As per Docket UE-399, the OCAT will be included in rates in Account 408.

PacifiCorp
Oregon General Rate Case - December 2027
Oregon Corporate Activity Tax & Metro SHS

			Metro Supportive Housing Services Tax	
Jun-25	12 months	Metro Supportive Housing Services Tax - Base Period	27,016	**Ref. 7.9**
Dec-27	12 months	Metro Supportive Housing Services Tax - 2027 Forecast	492,784	**Ref. 7.9**
		Total	492,784	
Adjustment to Account 40911			465,768	

Tab 8 - Rate Base

PacifiCorp **Page 8.0.1**
Oregon General Rate Case – December 2027
Rate Base Adjustment Index

The Company used year-end rate base as of June 2025 as the starting point for establishing the adjustments made to the test period. Test period electric plant in service is reflected using March 2027 ending balances. Other rate base components are reflected using a December 2027 13 month average balance. The following rate base adjustments are included.

8.1 Cash Working Capital
8.2 Trapper Mine Rate Base
8.3 Jim Bridger Mine Rate Base
8.4 Customer Advances for Construction
8.5 Pro Forma Plant Additions and Retirements
8.6 Regulatory Assets & Liabilities Amortization
8.7 Plant Held for Future Use
8.8 Pension and Other Post-retirement Plan Balances Removal
8.9 Capitalized Incentives
8.10 Remove Rolling Hills
8.11 Deer Creek Mine Adjustment
8.12 Emissions Control Equipment Adjustment
8.13 Transmission Project Adjustment
8.14 Cholla Unit 4 Retirement
8.15 Miscellaneous Rate Base
8.16 Carbon Plant Closure
8.17 Removal of Wildfire Mitigation Capital Rate Base
8.18 Dave Johnston Unit 4 Repairs
8.19 Klamath Regulatory Asset
8.20 New Wind Generation Capital Additions
8.21 Craig Unit 1 Retirement
8.22 Remove Large Energy-Use Facilities

PacifiCorp
Oregon General Rate Case - December 2027
Tab 8 Adjustment Summary

		8.2	8.3	8.4	8.5	8.6	8.7
	Total Adjustments	Trapper Mine Rate Base	Bridger Mine Rate Base	Customer Advances for Construction	Pro Forma Plant Additions and Retirements	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	-	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-	-
7							
8 Operating Expenses:							
9 Steam Production	(494,486)	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	(432,343)	-	-	-	-	-	-
12 Solar Production	-	-	-	-	-	-	-
13 Wind Production	2,262,348	-	-	-	-	-	-
14 Other Renewable Production	-	-	-	-	-	-	-
15 Other Power Supply	(211,104)	-	-	-	-	-	-
16 Transmission	-	-	-	-	-	-	-
17 Distribution	-	-	-	-	-	-	-
18 Customer Accounting	-	-	-	-	-	-	-
19 Customer Service & Info	-	-	-	-	-	-	-
20 Sales	-	-	-	-	-	-	-
21 Administrative & General	(676,297)	-	-	-	-	-	-
22							
23 Total O&M Expenses	448,117	-	-	-	-	-	-
24							
25 Depreciation	261,370	-	-	-	-	-	-
26 Amortization	(199,120)	-	-	-	-	-	-
27 Taxes Other Than Income	-	-	-	-	-	-	-
28 Income Taxes - Federal	2,618,998	(83,850)	(50,367)	(274,426)	(5,377,081)	113	26,934
29 Income Taxes - State	593,131	(18,990)	(11,407)	(62,150)	(1,217,760)	26	6,100
30 Income Taxes - Def Net	(8,343,109)	95,845	-	-	-	-	-
31 Investment Tax Credit Adj.	-	-	-	-	-	-	-
32 Misc Revenue & Expense	-	-	-	-	-	-	-
33							
34 Total Operating Expenses:	(4,620,613)	(6,994)	(61,774)	(336,576)	(6,594,841)	139	33,034
35							
36 Operating Rev For Return:	4,620,613	6,994	61,774	336,576	6,594,841	(139)	(33,034)
37							
38 Rate Base:							
39 Electric Plant In Service	746,381,682	882,717	9,289,856	-	991,804,886	-	-
40 Plant Held for Future Use	(4,968,037)	-	-	-	-	-	(4,968,037)
41 Misc Deferred Debits	(78,297,752)	-	-	-	-	-	-
42 Elec Plant Acq Adj	(20,914)	-	-	-	-	(20,914)	-
43 Nuclear Fuel	(44,191,249)	-	-	-	-	-	-
44 Prepayments	-	-	-	-	-	-	-
45 Fuel Stock	9,975,858	-	-	-	-	-	-
46 Material & Supplies	-	-	-	-	-	-	-
47 Working Capital	317,583	203,407	(1,874)	(10,212)	(200,095)	4	1,002
48 Weatherization Loans	-	-	-	-	-	-	-
49 Misc Rate Base	(14,356,267)	-	-	-	-	-	-
50							
51 Total Electric Plant:	614,840,905	1,086,124	9,287,981	(10,212)	991,604,791	(20,910)	(4,967,034)
52							
53 Rate Base Deductions:							
54 Accum Prov For Deprec	31,261,081	-	-	-	-	-	-
55 Accum Prov For Amort	-	-	-	-	-	-	-
56 Accum Def Income Tax	55,910,370	(34,464)	368	-	-	-	-
57 Unamortized ITC	-	-	-	-	-	-	-
58 Customer Adv For Const	50,617,975	-	-	50,617,975	-	-	-
59 Customer Service Deposits	-	-	-	-	-	-	-
60 Misc Rate Base Deductions	-	-	-	-	-	-	-
61							
62 Total Rate Base Deductions	137,789,426	(34,464)	368	50,617,975	-	-	-
63							
64 Total Rate Base:	752,630,331	1,051,660	9,288,349	50,607,763	991,604,791	(20,910)	(4,967,034)
65							
66 Return on Rate Base	-0.800%	-0.001%	-0.011%	-0.060%	-0.986%	0.000%	0.004%
67							
68 Return on Equity	-1.601%	-0.003%	-0.022%	-0.120%	-1.972%	0.000%	0.008%
69							
70 TAX CALCULATION:							
71 Operating Revenue	(510,367)	-	-	-	-	-	-
72 Other Deductions	-	-	-	-	-	-	-
73 Interest (AFUDC)	-	-	-	-	-	-	-
74 Interest	20,358,650	28,447	251,250	1,368,940	26,822,910	(566)	(134,358)
75 Schedule "M" Additions	(3,587,580)	(389,827)	-	-	-	-	-
76 Schedule "M" Deductions	(37,521,147)	-	-	-	-	-	-
77 Income Before Tax	13,064,549	(418,274)	(251,250)	(1,368,940)	(26,822,910)	566	134,358
78							
79 State Income Taxes	593,131	(18,990)	(11,407)	(62,150)	(1,217,760)	26	6,100
80 Taxable Income	12,471,418	(399,284)	(239,843)	(1,306,790)	(25,605,149)	540	128,258
81							
82 Federal Income Taxes + Other	2,618,998	(83,850)	(50,367)	(274,426)	(5,377,081)	113	26,934
APPROXIMATE PRICE CHANGE	71,699,814	99,449	878,341	4,785,661	93,769,886	(1,977)	(469,701)

PacifiCorp
Oregon General Rate Case - December 2027
Tab 8 Adjustment Summary

		8.8	8.9	8.1	8.1	8.1	8.1	8.14	8.15
		Pension and Other Post-retirement Plan Balances Removal	Captitalized Incentives	Remove Rolling Hills	Deer Creek Mine Adjustment	Emissions Control Investment Adjustment	Transmission Project Adjustment	Cholla Unit 4 Retirement	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	-	-	-	838,527	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-	-
11	Hydro Production	-	-	-	-	-	-	-	-
12	Solar Production	-	-	-	-	-	-	-	-
13	Wind Production	-	-	(231,611)	-	-	-	-	-
14	Other Renewable Production	-	-	-	-	-	-	-	-
15	Other Power Supply	-	-	(211,104)	-	-	-	-	-
16	Transmission	-	-	-	-	-	-	-	-
17	Distribution	-	-	-	-	-	-	-	-
18	Customer Accounting	-	-	-	-	-	-	-	-
19	Customer Service & Info	-	-	-	-	-	-	-	-
20	Sales	-	-	-	-	-	-	-	-
21	Administrative & General	-	-	(48,331)	-	(430,916)	-	(197,050)	-
22									
23	Total O&M Expenses	-	-	(491,046)	838,527	(430,916)	-	(197,050)	-
24									
25	Depreciation	-	(503,895)	-	-	(143,291)	-	-	-
26	Amortization	-	-	-	-	-	-	-	-
27	Taxes Other Than Income	-	-	-	-	-	-	-	-
28	Income Taxes - Federal	400,840	260,683	319,586	197,395	99,577	51,148	40,369	(51,984)
29	Income Taxes - State	90,779	59,037	72,377	44,704	22,552	11,584	9,143	(11,773)
30	Income Taxes - Def Net	-	(123,891)	(14,592)	(310,020)	22,875	-	-	-
31	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
32	Misc Revenue & Expense	-	-	-	-	-	-	-	-
33									
34	Total Operating Expenses:	491,619	(308,065)	(113,675)	770,606	(429,204)	62,732	(147,538)	(63,756)
35									
36	Operating Rev For Return:	(491,619)	308,065	113,675	(770,606)	429,204	(62,732)	147,538	63,756
37									
38	Rate Base:								
39	Electric Plant In Service	-	-	(54,522,921)	-	(635,634)	(10,496,535)	-	-
40	Plant Held for Future Use	-	-	-	-	-	-	-	-
41	Misc Deferred Debits	(53,567,392)	-	-	(21,961,296)	-	-	(155,545)	(387,470)
42	Elec Plant Acq Adj	-	-	-	-	-	-	-	-
43	Nuclear Fuel	(44,191,249)	-	-	-	-	-	-	-
44	Prepayments	-	-	-	-	-	-	-	-
45	Fuel Stock	-	-	-	-	-	-	-	9,975,858
46	Material & Supplies	-	-	-	-	-	-	-	-
47	Working Capital	14,916	9,701	(3,006)	32,787	(9,369)	1,903	(4,476)	(1,934)
48	Weatherization Loans	-	-	-	-	-	-	-	-
49	Misc Rate Base	-	(14,356,267)	-	-	-	-	-	-
50									
51	Total Electric Plant:	(97,743,725)	(14,346,566)	(54,525,927)	(21,928,508)	(645,003)	(10,494,631)	(160,021)	9,586,454
52									
53	Rate Base Deductions:								
54	Accum Prov For Deprec	-	-	3,963,415	-	-	490,593	-	-
55	Accum Prov For Amort	-	-	-	-	-	-	-	-
56	Accum Def Income Tax	23,823,575	3,529,718	11,973,933	1,141,985	69,785	571,597	-	-
57	Unamortized ITC	-	-	-	-	-	-	-	-
58	Customer Adv For Const	-	-	-	-	-	-	-	-
59	Customer Service Deposits	-	-	-	-	-	-	-	-
60	Misc Rate Base Deductions	-	-	-	-	-	-	-	-
61									
62	Total Rate Base Deductions	23,823,575	3,529,718	15,937,348	1,141,985	69,785	1,062,190	-	-
63									
64	Total Rate Base:	(73,920,150)	(10,816,848)	(38,588,579)	(20,786,524)	(575,219)	(9,432,441)	(160,021)	9,586,454
65									
66	Return on Rate Base	0.063%	0.015%	0.039%	0.008%	0.007%	0.008%	0.003%	-0.008%
67									
68	Return on Equity	0.126%	0.031%	0.079%	0.016%	0.015%	0.017%	0.005%	-0.017%
69									
70	TAX CALCULATION:								
71	Operating Revenue	-	503,895	491,046	(838,527)	574,207	-	197,050	-
72	Other Deductions	-	-	-	-	-	-	-	-
73	Interest (AFUDC)	-	-	-	-	-	-	-	-
74	Interest	(1,999,540)	(292,596)	(1,043,821)	(562,275)	(15,560)	(255,148)	(4,329)	259,314
75	Schedule "M" Additions	-	-	-	1,293,411	(143,291)	-	-	-
76	Schedule "M" Deductions	-	(503,895)	(59,350)	32,480	(50,253)	-	-	-
77	Income Before Tax	1,999,540	1,300,385	1,594,217	984,679	496,729	255,148	201,378	(259,314)
78									
79	State Income Taxes	90,779	59,037	72,377	44,704	22,552	11,584	9,143	(11,773)
80	Taxable Income	1,908,761	1,241,348	1,521,840	939,974	474,178	243,564	192,236	(247,541)
81									
82	Federal Income Taxes + Other	400,840	260,683	319,586	197,395	99,577	51,148	40,369	(51,984)
	APPROXIMATE PRICE CHANGE	(6,990,168)	(1,544,434)	(4,157,336)	(1,097,740)	(648,724)	(891,967)	(219,087)	906,531

PacifiCorp
Oregon General Rate Case - December 2027
Tab 8 Adjustment Summary

		8.16	8.17	8.18	8.19	8.20	8.21	8.22
		Carbon Plant Closure	Removal of Wildfire Mitigation Capital Rate Base	Dave Johnston Unit 4 Repairs	Klamath Regulatory Asset	New Wind Generation Capital Additions_CONF	Craig Unit 1 Retirement	Remove Large Energy-Use Facilities
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	-	-	-	-	-	(1,333,013)	-
10	Nuclear Production	-	-	-	-	-	-	-
11	Hydro Production	-	-	-	(432,343)	-	-	-
12	Solar Production	-	-	-	-	-	-	-
13	Wind Production	-	-	-	-	2,493,958	-	-
14	Other Renewable Production	-	-	-	-	-	-	-
15	Other Power Supply	-	-	-	-	-	-	-
16	Transmission	-	-	-	-	-	-	-
17	Distribution	-	-	-	-	-	-	-
18	Customer Accounting	-	-	-	-	-	-	-
19	Customer Service & Info	-	-	-	-	-	-	-
20	Sales	-	-	-	-	-	-	-
21	Administrative & General	-	-	-	-	-	-	-
22								
23	Total O&M Expenses	-	-	-	(432,343)	2,493,958	(1,333,013)	-
24								
25	Depreciation	-	(4,642,835)	176,528	-	10,009,665	(1,151,787)	(3,483,017)
26	Amortization	(179,487)	-	-	(19,633)	-	-	-
27	Taxes Other Than Income	-	-	-	-	-	-	-
28	Income Taxes - Federal	36,748	5,012,895	(50,399)	(156,647)	(3,045,656)	498,237	4,764,882
29	Income Taxes - State	8,322	1,135,282	(11,414)	(35,476)	(689,757)	112,837	1,079,114
30	Income Taxes - Def Net	-	(3,707,663)	906	313,793	(890,384)	-	(3,729,978)
31	Investment Tax Credit Adj.	-	-	-	-	-	-	-
32	Misc Revenue & Expense	-	-	-	-	-	-	-
33								
34	Total Operating Expenses:	(134,417)	(2,202,321)	115,621	(330,306)	7,877,828	(1,873,726)	(1,368,999)
35								
36	Operating Rev For Return:	134,417	2,202,321	(115,621)	330,306	(7,877,828)	1,873,726	1,368,999
37								
38	Rate Base:							
39	Electric Plant In Service	-	(226,512,418)	645,425	-	250,799,753	(18,109,626)	(196,763,820)
40	Plant Held for Future Use	-	-	-	-	-	-	-
41	Misc Deferred Debits	(148,850)	-	-	(2,077,199)	-	-	-
42	Elec Plant Acq Adj	-	-	-	-	-	-	-
43	Nuclear Fuel	-	-	-	-	-	-	-
44	Prepayments	-	-	-	-	-	-	-
45	Fuel Stock	-	-	-	-	-	-	-
46	Material & Supplies	-	-	-	-	-	-	-
47	Working Capital	1,367	186,543	(1,875)	(18,947)	(37,667)	(21,904)	177,314
48	Weatherization Loans	-	-	-	-	-	-	-
49	Misc Rate Base	-	-	-	-	-	-	-
50								
51	Total Electric Plant:	(147,483)	(226,325,875)	643,550	(2,096,146)	250,762,086	(18,131,531)	(196,586,506)
52								
53	Rate Base Deductions:							
54	Accum Prov For Deprec	-	19,762,298	2,034,513	-	(17,054,751)	18,109,626	3,955,388
55	Accum Prov For Amort	-	-	-	-	-	-	-
56	Accum Def Income Tax	6,124	11,245,450	(46,045)	510,713	(410,693)	-	3,528,325
57	Unamortized ITC	-	-	-	-	-	-	-
58	Customer Adv For Const	-	-	-	-	-	-	-
59	Customer Service Deposits	-	-	-	-	-	-	-
60	Misc Rate Base Deductions	-	-	-	-	-	-	-
61								
62	Total Rate Base Deductions	6,124	31,007,747	1,988,468	510,713	(17,465,444)	18,109,626	7,483,713
63								
64	Total Rate Base:	(141,359)	(195,318,128)	2,632,017	(1,585,434)	233,296,642	(21,904)	(189,102,793)
65								
66	Return on Rate Base	0.002%	0.236%	-0.005%	0.007%	-0.364%	0.030%	0.211%
67								
68	Return on Equity	0.005%	0.472%	-0.009%	0.014%	-0.728%	0.060%	0.422%
69								
70	TAX CALCULATION:							
71	Operating Revenue	179,487	4,642,835	(176,528)	451,976	(12,503,624)	2,484,800	3,483,017
72	Other Deductions	-	-	-	-	-	-	-
73	Interest (AFUDC)	-	-	-	-	-	-	-
74	Interest	(3,824)	(5,283,355)	71,196	(42,886)	6,310,674	(593)	(5,115,231)
75	Schedule "M" Additions	-	(777,206)	176,528	-	(264,179)	-	(3,483,017)
76	Schedule "M" Deductions	-	(15,857,225)	180,213	1,276,277	(3,885,598)	-	(18,653,796)
77	Income Before Tax	183,311	25,006,210	(251,409)	(781,416)	(15,192,879)	2,485,392	23,769,027
78								
79	State Income Taxes	8,322	1,135,282	(11,414)	(35,476)	(689,757)	112,837	1,079,114
80	Taxable Income	174,988	23,870,928	(239,995)	(745,939)	(14,503,122)	2,372,555	22,689,913
81								
82	Federal Income Taxes + Other	36,748	5,012,895	(50,399)	(156,647)	(3,045,656)	498,237	4,764,882
	APPROXIMATE PRICE CHANGE	(199,144)	(23,275,550)	431,607	(617,739)	35,003,196	(2,573,945)	(21,487,343)

PacifiCorp PAGE 8.1
Oregon General Rate Case - December 2027
Cash Working Capital

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Cash Working Capital	CWC	3	(1,429,885)	OR	Situs	(1,429,885)	Below
Adjustment Detail:							
Cash Working Capital June 2025 - Unadjusted			89,375,839			37,944,013	2.28
Cash Working Capital December 2027 - Normalized			64,396,835			36,514,128	2.28
Adjustment:			(24,979,004)			(1,429,885)	

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.

PacifiCorp
Update Cash Working Capital
Twelve Months Ending December 31, 2027

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	2,598,760,029	43,427,298	1,146,057,645	104,927,786	150,924,956	132,187,061	557,380,405	68,968,895	18,737,894	31,455
Taxes Other than Income	271,441,309	8,747,414	112,881,934	14,947,627	28,392,513	24,818,635	95,024,512	11,441,537	3,573,877	5,774
Federal Income Tax	411,715,574	3,088,165	(60,628,691)	46,533,813	85,726,615	73,328,230	271,750,335	41,597,805	12,398,385	3,377,668
State Income Tax	121,278,480	699,803	5,141,589	10,539,709	19,416,675	16,608,513	61,550,903	9,421,613	2,808,162	764,949
Total	3,403,195,393	55,962,680	1,203,452,478	176,948,935	284,460,758	246,942,440	985,706,154	131,429,849	37,518,318	4,179,846
Divided by Days in Year	365	365	365	365	365	365	365	365	365	365
Avg. Daily Cost of Service	9,323,823	153,322	3,297,130	484,792	779,345	676,555	2,700,565	360,082	102,790	11,452
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	**64,396,835**	**241,806**	36,514,128	2,942,685	5,462,299	4,741,861	20,844,959	(1,615,102)	720,438	6,061
	Ref. 2.33	**Ref. 2.33**								

PacifiCorp PAGE 8.2
Oregon General Rate Case - December 2027
Trapper Mine Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Tangible Property	399	1	5,798,753	SE	26.823%	1,555,387	Below
Other Tangible Property	399	3	(2,507,831)	SE	26.823%	(672,670)	Below
			3,290,922			882,717	Below
Final Reclamation Liability	2533	3	769,968	SE	26.823%	206,527	Below
Adjustment to Tax:							
Schedule M Adj - Reclamation Liab	SCHMAT	3	(1,453,342)	SE	26.823%	(389,827)	8.2.2
Deferred Income Tax Expense	41110	3	357,327	SE	26.823%	95,845	8.2.2
Accumulated Def Inc Tax Balance	190	3	(128,488)	SE	26.823%	(34,464)	8.2.2

Adjustment Detail

Other Tangible Property		
June 2025 End of Period Balance	5,798,753	8.2.1
December 2027 13 Mth Avg Balance	3,290,922	8.2.1
Adjust to December 2027 13 Mth Avg Balance	(2,507,831)	Above
Final Reclamation Liability		
June 2025 12 Mth. Average	(10,619,764)	8.2.2
December 2027 12 Mth. Average	(9,849,796)	8.2.2
Adjust to December 2027 12 Mth. Average	769,968	Above

Description of Adjustment:

The Company owns 29.14% interest in the Trapper Mine, which provides coal to the Craig generating plant. The normalized coal cost of Trapper includes all operating and maintenance costs, but it does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine plant investment to the rate base. It reflects net plant to recognize the depreciation of the investment over time. This adjustment also walks forward the Reclamation Liability to December 2027 levels. The adjustment was stipulated to and approved in Oregon UE 111, and it has been included in all filings since.

PacifiCorp
Oregon General Rate Case - December 2027
Trapper Mine Rate Base

DESCRIPTION	Jun-25 Actual	Dec-26 Forecast	Jan-27 Forecast	Feb-27 Forecast	Mar-27 Forecast	Apr-27 Forecast	May-27 Forecast	Jun-27 Forecast	Jul-27 Forecast	Aug-27 Forecast	Sep-27 Forecast	Oct-27 Forecast	Nov-27 Forecast	Dec-27 Forecast
Property, Plant, and Equipment														
Lands and Leases	12,327,379	12,327,379	12,327,379	12,327,379	12,327,379	12,327,379	12,327,379	12,327,379	12,327,379	12,327,379	12,327,379	12,327,379	12,327,379	12,327,379
Development Costs	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815
Equipment and Facilities	122,089,934	123,424,611	123,424,611	123,155,062	123,155,062	123,155,062	122,089,934	122,089,934	122,089,934	122,089,934	122,980,075	123,325,828	123,424,611	123,424,611
Total Property, Plant, and Equipment	137,252,128	138,586,805	138,586,805	138,317,256	138,317,256	138,317,256	137,252,128	137,252,128	137,252,128	137,252,128	138,142,269	138,488,022	138,586,805	138,586,805
Accumulated Depreciation	(127,316,605)	(129,858,523)	(129,998,025)	(130,137,527)	(130,277,029)	(130,416,531)	(130,556,033)	(130,695,535)	(130,835,037)	(130,974,538)	(131,114,040)	(131,253,542)	(131,393,044)	(131,532,546)
Total Property, Plant, and Equipment	9,935,523	8,728,282	8,588,780	8,179,729	8,040,227	7,900,725	6,696,095	6,556,593	6,417,091	6,277,589	7,028,229	7,234,479	7,193,761	7,054,259
Other														
Inventories	5,709,234	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
Prepaid Expenses	383,874	317,162	182,502	191,531	165,872	372,627	321,635	307,099	266,222	231,895	215,418	200,754	231,461	253,730
Restricted Funds: Self-bonding for Black Lung	666,275	666,275	666,275	666,275	666,275	666,275	666,275	666,275	666,275	666,275	666,275	666,275	666,275	666,275
Advanced Stripping Costs	3,204,728	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred GE Royalty Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Advance Royalty - State 206-13	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other	9,964,111	3,983,437	3,848,777	3,857,807	3,832,147	4,038,903	3,987,911	3,973,375	3,932,498	3,898,170	3,881,694	3,867,030	3,897,736	3,920,005
Total Rate Base	19,899,634	12,711,720	12,437,557	12,037,536	11,872,375	11,939,628	10,684,006	10,529,968	10,349,589	10,175,759	10,909,922	11,101,509	11,091,497	10,974,264
PacifiCorp Share	**5,798,753**	**3,704,195**	**3,624,304**	**3,507,738**	**3,459,610**	**3,479,208**	**3,113,319**	**3,068,433**	**3,015,870**	**2,965,216**	**3,179,151**	**3,234,980**	**3,232,062**	**3,197,900**
	Ref. 8.2													

December 2027 13 Mth. Avg. Balance	**3,290,922**
	Ref. 8.2

PacifiCorp
Oregon General Rate Case - December 2027
Trapper Mine
Final Reclamation Liability

Actual

Description:	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Final Reclamation Liability	(10,518,296)	(10,494,956)	(10,548,413)	(10,564,024)	(10,511,629)	(10,614,977)	(10,609,678)	(10,627,436)	(10,629,016)	(10,766,596)	(10,829,428)	(10,722,720)

Pro Forma

Description:	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
Final Reclamation Liability	(10,353,739)	(10,262,113)	(10,170,487)	(10,078,861)	(9,987,235)	(9,895,609)	(9,803,983)	(9,712,357)	(9,620,731)	(9,529,105)	(9,437,479)	(9,345,853)

12 Month Average :

June 2025 12 Mth. Avg. Balance	(10,619,764)	
December 2027 12 Mth. Avg. Balance	(9,849,796)	
Adjustment to Rate Base	**769,968**	**Ref 8.2**

Adjustments for Tax:

Change in Liability Account Balance:

Schedule M Add - Pro Forma	**(1,376,867)**	
SCHMAT 605.715 - Actual	76,475	
Adjustment needed	**(1,453,342)**	**Ref 8.2**
Def Inc Tax Exp - Pro Forma	**338,525**	
41110 605.715 - Actual	(18,802)	
Adjustment needed	**357,327**	**Ref 8.2**

ADIT Adjustment for Tax:

Tax Actual Account 287216 (FERC Account 190) 605.715

Description:	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
Trapper Mine Contract Obligation	2,542,679	2,536,100	2,530,362	2,548,977	2,552,815	2,539,933	2,513,500	2,512,198	2,516,564	2,543,661	2,577,487	2,592,935	2,561,482

Regulation Forecast

Description:	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
Trapper Mine Contract Obligation	2,568,160	2,545,632	2,523,105	2,500,577	2,478,049	2,455,522	2,432,994	2,410,466	2,387,938	2,365,411	2,342,883	2,320,355	2,297,827

	Acct. 287216
June 2025 End of Period ADIT Balance	2,561,482
December 2027 13MA ADIT Balance	2,432,994
Adjustment to Rate Base	**(128,488)**
	Ref 8.2

PacifiCorp PAGE 8.3
Oregon General Rate Case - December 2027
Jim Bridger Mine Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Tangible Property	399	1	42,081,938	SE	26.823%	11,287,548	Below
Other Tangible Property	399	3	(7,447,745)	SE	26.823%	(1,997,693)	Below
			34,634,193			9,289,856	
Adjustment to Tax:							
Accumulated Def Inc Tax Balance	190	3	1,372	SE	26.823%	368	8.3.2
Adjustment Detail							
June 2025 End of Period Balance			42,081,938				8.3.1
December 2027 13 Mo. Avg. Balance			34,634,193				8.3.1
Adjustment to December 2027 13 Mth. Avg. Balance			(7,447,745)				8.3.1

Description of Adjustment:

The Company owns a two-thirds interest in the Bridger Coal Company (BCC), which supplies coal to the Jim Bridger generating plant. The Company's investment in BCC is recorded on the books of Pacific Minerals, INC (PMI), a wholly-owned subsidiary. Because of this ownership arrangement, the coal mine investment is not included in Account 101 - Electric Plant in Service. The normalized costs for BCC provides no return on investment. The return on investment for BCC is removed in the fuels credit which the Company has included as an offset to fuel prices leaving no return in results. The Bridger Mine adjustment was stipulated to and approved in Oregon UE 111, and has been included in all filings since.

PacifiCorp
Oregon General Rate Case - December 2027
Jim Bridger Mine Rate Base
(000's)

Bridger Total	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
Description	**June 24**	**July 24**	**Aug 24**	**Sept 24**	**Oct 24**	**Nov 24**	**Dec 24**	**Jan 25**	**Feb 25**	**Mar 25**	**Apr 25**	**May 25**	**June 25**
1 Structure, Equipment, Mine Dev.	278,834	278,834	279,314	280,840	281,151	280,027	278,388	254,011	254,034	254,034	255,564	255,717	255,584
2 Materials & Supplies	11,672	11,426	11,546	11,630	11,578	11,444	12,012	12,259	12,157	11,913	11,730	11,774	12,071
4 Pit Inventory	7,556	2,612	4,094	5,552	4,716	4,378	4,349	4,993	4,519	3,793	4,151	3,560	6,408
5 Deferred Long Wall Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
6 Reclamation Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Accumulated Depreciation	(211,556)	(212,503)	(213,483)	(214,421)	(214,792)	(213,997)	(213,294)	(206,467)	(207,385)	(208,303)	(209,251)	(210,162)	(210,939)
8 Bonus Bid / Lease Payable	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE	86,505	80,369	81,471	83,601	82,654	81,853	81,456	64,795	63,326	61,437	62,194	60,890	63,123
PacifiCorp Share (66.67%)	**57,670**	**53,579**	**54,314**	**55,734**	**55,102**	**54,569**	**54,304**	**43,197**	**42,217**	**40,958**	**41,463**	**40,593**	**42,082**

Bridger Total	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma
Description	**Dec 26**	**Jan 27**	**Feb 27**	**Mar 27**	**Apr 27**	**May 27**	**June 27**	**July 27**	**Aug 27**	**Sept 27**	**Oct 27**	**Nov 27**	**Dec 27**
1 Structure, Equipment, Mine Dev.	263,778	263,797	263,816	263,835	264,066	264,110	264,129	264,400	278,761	278,828	279,551	279,569	279,587
2 Materials & Supplies	12,273	12,282	12,301	12,320	12,339	12,358	12,377	12,396	12,415	12,434	12,454	12,473	12,492
4 Pit Inventory	3,091	2,719	2,725	2,767	3,660	3,910	3,228	3,519	5,749	7,227	9,846	8,457	3,554
5 Deferred Long Wall Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
6 Reclamation Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Accumulated Depreciation	(228,027)	(229,103)	(230,138)	(231,185)	(232,236)	(233,287)	(234,344)	(235,418)	(236,983)	(238,529)	(240,101)	(241,673)	(243,203)
8 Bonus Bid / Lease Payable	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE	51,115	49,695	48,704	47,737	47,829	47,091	45,390	44,898	59,942	59,961	61,749	58,826	52,430
PacifiCorp Share (66.67%)	**34,076**	**33,130**	**32,470**	**31,824**	**31,886**	**31,394**	**30,260**	**29,932**	**39,961**	**39,974**	**41,166**	**39,217**	**34,954**

June 2025 - End of Period Balance	**42,082**	**Ref 8.3**
December 2027 - 13 Mth. Avg. Balance	**34,634**	**Ref 8.3**

PacifiCorp
Oregon General Rate Case - December 2027
Jim Bridger Mine Rate Base

	Dec 26	Jan 27	Feb 27	Mar 27	Apr 27	May 27	June 27	July 27	Aug 27	Sept 27	Oct 27	Nov 27	Dec 27
Materials & Supplies:													
Obsolete Reserve - Surface	-	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	-
Obsolete Reserve - Underground	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Obsolete Reserves	-	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	(9,895)	-
		0											
PacifiCorp's 2/3 share:													
Obsolete Reserve - Surface	-	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	-
Obsolete Reserve - Underground	-	-	-	-	-	-	-	-	-	-	-	-	-
Total of PacifiCorp's share of Obsolete Reserves	-	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	(6,597)	-

13MA ADIT 190 Balance at December 31, 2027 - SAP Acct 287938	**1,372**	
YE ADIT 190 Balance at June 30, 2025 - SAP Acct 287938	-	
	1,372	**Ref 8.3**

PacifiCorp PAGE 8.4
Oregon General Rate Case - December 2027
Customer Advances for Construction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Customer Advances	252	1	(282,950)	CA	Situs	-	8.4.1
Customer Advances	252	1	54,789,014	OR	Situs	54,789,014	8.4.1
Customer Advances	252	1	(736,463)	WA	Situs	-	8.4.1
Customer Advances	252	1	(1,574,607)	ID	Situs	-	8.4.1
Customer Advances	252	1	(35,748,815)	UT	Situs	-	8.4.1
Customer Advances	252	1	(1,418,426)	WYP	Situs	-	8.4.1
Customer Advances	252	1	(15,027,753)	SG	27.76%	(4,171,039)	8.4.1
Total			-			50,617,975	

Description of Adjustment:

Customer advances for construction are booked into FERC account 252. When they are booked, the entries do not reflect the proper allocation. This adjustment corrects the allocation of customer advances for construction in the account.

PacifiCorp PAGE 8.4.1
Oregon General Rate Case - December 2027
Customer Advances for Construction

END OF PERIOD BASIS:

Account	Booked Allocation	Correct Allocation	Adjustment	Ref.
252CA	-	(282,950)	**(282,950)**	**Page 8.4**
252OR	(64,843,129)	(10,054,115)	**54,789,014**	**Page 8.4**
252WA	-	(736,463)	**(736,463)**	**Page 8.4**
252IDU	-	(1,574,607)	**(1,574,607)**	**Page 8.4**
252UT	(885,625)	(36,634,440)	**(35,748,815)**	**Page 8.4**
252WYP	-	(1,418,426)	**(1,418,426)**	**Page 8.4**
252SG	(84,837,851)	(99,865,604)	**(15,027,753)**	**Page 8.4**
Total	**(150,566,605)**	**(150,566,605)**	**-**	

PacifiCorp PAGE 8.5
Oregon General Rate Case - December 2027
Pro Forma Plant Additions and Retirements

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Plant	312	3	(3,726,420)	SG	27.756%	(1,034,289)	
Steam Plant	312	3	(6,695,116)	SG	27.756%	(1,858,268)	
Steam Plant	312	3	100,035,868	SG	27.756%	27,765,530	
Hydro Plant	332	3	(607,333)	SG	27.756%	(168,569)	
Hydro Plant	332	3	(393,139)	SG	27.756%	(109,118)	
Hydro Plant	332	3	144,154,118	SG-P	27.756%	40,010,804	
Hydro Plant	332	3	36,803,166	SG-U	27.756%	10,214,930	
Solar Plant	338XP	3	148,724	OR	100.000%	148,724	
Solar Plant	338XP	3	(2,529)	UT	0.000%	-	
Wind Plant	338WP	3	40,639,362	SG	27.756%	11,279,689	
Renewable Plant	339RP	3	1,641,900	SG	27.756%	455,719	
Other Plant	343	3	56,136,524	SG	27.756%	15,581,015	
Other Plant	343	3	(571,430)	SG	27.756%	(158,604)	
Transmission Plant	355	3	196,763,820	OR	100.000%	196,763,820	
Transmission Plant	355	3	(3,484,388)	SG	27.756%	(967,112)	
Transmission Plant	355	3	(6,064,126)	SG	27.756%	(1,683,133)	
Transmission Plant	355	3	920,263,852	SG	27.756%	255,424,521	
Distribution Plant	360	3	14,618,707	Situs	100.000%	3,529,801	
Distribution Plant	361	3	27,859,426	Situs	100.000%	6,726,876	
Distribution Plant	362	3	231,558,795	Situs	100.000%	55,911,676	
Distribution Plant	363	3	37,443,667	Situs	100.000%	9,041,065	
Distribution Plant	364	3	329,868,728	Situs	100.000%	79,649,376	
Distribution Plant	365	3	211,936,445	Situs	100.000%	51,173,707	
Distribution Plant	366	3	98,378,611	Situs	100.000%	23,754,282	
Distribution Plant	367	3	226,508,925	Situs	100.000%	54,692,345	
Distribution Plant	368	3	311,420,590	Situs	100.000%	75,194,929	
Distribution Plant	369	3	200,084,164	Situs	100.000%	48,311,881	
Distribution Plant	370	3	57,450,659	Situs	100.000%	13,871,910	
Distribution Plant	371	3	1,581,465	Situs	100.000%	381,857	
Distribution Plant	372	3	-	Situs	100.000%	-	
Distribution Plant	373	3	11,885,129	Situs	100.000%	2,869,757	
Distribution Plant	363	3	1,883,228	SNPD	25.578%	481,694	
General Plant	397	3	(243,623)	CA	0.000%	-	
General Plant	397	3	(4,366,588)	OR	100.000%	(4,366,588)	
General Plant	397	3	(577,685)	WA	0.000%	-	
General Plant	397	3	4,787,801	WYP	0.000%	-	
General Plant	397	3	10,711,987	UT	0.000%	-	
General Plant	397	3	939,955	ID	0.000%	-	
General Plant	397	3	(360,714)	WYU	0.000%	-	
General Plant	397	3	(178,002)	SG	27.756%	(49,405)	
General Plant	397	3	(562,311)	SG	27.756%	(156,073)	
General Plant	397	3	(15,459,144)	SG	27.756%	(4,290,774)	
General Plant	397	3	110,022,968	SO	27.909%	30,706,191	
General Plant	397	3	(6,804)	SG	27.756%	(1,888)	
General Plant	397	3	(1,593,833)	CN	30.140%	(480,377)	
General Plant	397	3	(268,494)	SE	26.823%	(72,018)	
			3,340,366,903			998,545,880	

Description of Adjustment:

To reasonably represent the cost of system infrastructure required to serve customers, the company has identified capital projects that are forecast to be used and useful by March 31, 2027. This adjustment incorporates into test period results the projected capital additions placed in service through that date, stated on a 13-month average basis calculated for the 2027 calendar year. Capital additions are summarized by functional category on separate supporting schedules, which identify the in-service date and investment amount for each project. Projects with a total company cost exceeding $10 million are described in detail on pages 8.5.51 through 8.5.60. Plant retirements are also reflected and have been walked forward through the test period. Accordingly, this adjustment reflects the net impact of projected capital additions and retirements.

The tax portion of this adjustment represents the tax impacts of the difference between book depreciation for the original capital additions submitted and included in 7.2 - PowerTax adjustment and the final level of book depreciation included in Adjustments 6.1 & 6.2.

PacifiCorp PAGE 8.5.1
Oregon General Rate Case - December 2027
(cont.) Pro Forma Plant Additions and Retirements

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Intangible Plant	303	3	(3,021)	CA	0.000%	-	
Intangible Plant	303	3	(3,178,870)	CN	30.140%	(958,104)	
Intangible Plant	303	3	-	SG	27.756%	-	
Intangible Plant	303	3	-	SG	27.756%	-	
Intangible Plant	303	3	(4,982)	ID	0.000%	-	
Intangible Plant	303	3	(4,629)	OR	100.000%	(4,629)	
Intangible Plant	303	3	-	SE	26.823%	-	
Intangible Plant	303	3	(6,484,233)	SG	27.756%	(1,799,736)	
Intangible Plant	302	3	-	SG-P	27.756%	-	
Intangible Plant	302	3	(306,443)	SG-U	27.756%	(85,055)	
Intangible Plant	302	4	(42,240)	SG	27.756%	(11,724)	
Intangible Plant	303	3	-	SG	27.756%	-	
Intangible Plant	303	3	(13,908,637)	SO	27.909%	(3,881,746)	
Intangible Plant	303	3	(8,293)	UT	0.000%	-	
Intangible Plant	303	3	(5,175)	WA	0.000%	-	
Intangible Plant	303	3	(137,121)	WYP	0.000%	-	
Intangible Plant	303	3	-	WYU	0.000%	-	
Sub-total			(24,083,644)			(6,740,994)	
Total			3,316,283,259			991,804,886	8.5.4

Description of Adjustment:

To reasonably represent the cost of system infrastructure required to serve customers, the company has identified capital projects that are forecast to be used and useful by March 31, 2027. This adjustment incorporates into test period results the projected capital additions placed in service through that date, stated on a 13-month average basis calculated for the 2027 calendar year. Capital additions are summarized by functional category on separate supporting schedules, which identify the in-service date and investment amount for each project. Projects with a total company cost exceeding $10 million are described in detail on pages 8.5.51 through 8.5.60. Plant retirements are also reflected and have been walked forward through the test period. Accordingly, this adjustment reflects the net impact of projected capital additions and retirements.

The tax portion of this adjustment represents the tax impacts of the difference between book depreciation for the original capital additions submitted and included in 7.2 - PowerTax adjustment and the final level of book depreciation included in Adjustment 6.1 and 6.2.

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
and Retirements

Description	FERC Account	2020P Factor	Year End Jun-25 EPIS Balance	13 Month Average Dec 2027 EPIS Balance	Adjustment to Test Period
Steam Production Plant:					
Pre-merger Pacific	312	SG	987,592,112	983,865,693	(3,726,420)
Pre-merger Utah	312	SG	1,014,704,747	1,008,009,631	(6,695,116)
Post-merger	312	SG	5,111,725,243	5,211,761,111	100,035,868
Post-merger	312	SG	1,266,851	1,266,851	-
Post-merger	312	SG	-	-	-
Post-Merger	312	SG	-	-	-
Post-Merger	312	SG	-	-	-
Post-merger	312	SG	-	-	-
Total Steam Plant			7,115,288,953	7,204,903,285	89,614,332
Hydro Production Plant:					
Pre-merger Pacific	332	SG	173,759,313	173,151,980	(607,333)
Pre-merger Utah	332	SG	39,567,052	39,173,912	(393,139)
Post-merger	332	SG	13,047,000	13,047,000	-
Post-merger	332	SG-P	749,688,597	893,842,714	144,154,118
Post-merger	332	SG-U	168,988,088	205,791,254	36,803,166
Total Hydro Plant			1,145,050,050	1,325,006,862	179,956,811
Solar Production Plant:					
Oregon	338XP	OR	770,480	919,203	148,724
Utah	338XP	UT	561,017	558,487	(2,529)
Post-merger	338XP	SG	56,322	56,322	-
Post-merger	338XP	OTHER	-	-	-
Total Other Plant			1,387,818	1,534,013	146,195
Wind Production Plant:					
Oregon	338WP	OR	-	-	-
Utah	338WP	UT	-	-	-
Post-merger	338WP	SG	3,805,799,747	3,846,439,109	40,639,362
Post-merger	338WP	OTHER	-	-	-
Total Other Plant			3,805,799,747	3,846,439,109	40,639,362
Renewable Production Plant:					
Oregon	339RP	OR	-	-	-
Utah	339RP	UT	-	-	-
Post-merger	339RP	SG	157,826,749	159,468,649	1,641,900
Post-merger	339RP	OTHER	0	0	0
Total Other Plant			157,826,749	159,468,649	1,641,900
Other Production Plant:					
Pre-merger Pacific	343	SG	-	-	-
Pre-merger Utah	343	SG	235,129	235,129	-
Post-merger	343	SG	1,974,191,377	2,030,327,901	56,136,524
Post-merger	343	SG	88,883,413	88,311,982	(571,430)
Post-merger	343	SG	2,063,309,919	2,118,875,013	55,565,094
Total Other Plant					
Transmission Plant:					
California	352	CA	-	-	-
Oregon	352	OR	-	196,763,820	196,763,820
Washington	352	WA	-	-	-
Wyoing	352	WYP	-	-	-
Wyoming	352	WYU	-	-	-
Utah	352	UT	-	-	-
Idaho	352	ID	-	-	-
System	355	OTHER	-	-	-
Pre-merger Pacific	355	SG	472,345,011	468,860,623	(3,484,388)
Pre-merger Utah	355	SG	604,989,761	598,925,634	(6,064,126)
Post-merger	355	SG	10,372,730,659	11,292,994,511	920,263,852
Total Transmission Plant			11,450,065,431	12,557,544,589	1,107,479,158

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
and Retirements

Description	FERC Account	2020P Factor	Year End Jun-25 EPIS Balance	13 Month Average Dec 2027 EPIS Balance	Adjustment to Test Period
Distribution Plant:					
California	360-373	CA	590,906,802	827,396,454	236,489,652
Oregon	360-373	OR	3,137,515,987	3,562,625,448	425,109,461
Washington	360-373	WA	711,585,848	749,000,099	37,414,251
Eastern Wyoming	360-373	WYP	806,826,853	944,996,965	138,170,112
Utah	360-373	UT	4,430,786,259	5,296,719,195	865,932,936
Idaho	360-373	ID	497,264,321	555,841,103	58,576,782
Western Wyoming	360-373	WYU	166,489,437	165,391,554	(1,097,882)
System	363	SNPD	35,847,239	37,730,467	1,883,228
System	363	CN	10,802,634	10,802,634	-
System	363	SO	-	-	-
System	363	SG	-	-	-
System	363	OTHER	-	-	-
Total Distribution Plant			10,388,025,380	12,150,503,920	1,762,478,540
Energy Storage Plant					
California	387	CA	-	-	-
Oregon	387	OR	-	-	-
Washington	387	WA	-	-	-
Eastern Wyoming	387	WYP	-	-	-
Utah	387	UT	-	-	-
Idaho	387	ID	-	-	-
Western Wyoming	387	WYU	-	-	-
System	387	CN	-	-	-
System	387	SNPD	-	-	-
System	387	SG	-	-	-
System	387	SO	-	-	-
System	387	OTHER	-	-	-
Total Energy Storage Plant			-	-	-
General Plant:					
California	397	CA	16,709,229	16,465,606	(243,623)
Oregon	397	OR	161,745,989	157,379,400	(4,366,588)
Washington	397	WA	38,216,878	37,639,193	(577,685)
Eastern Wyoming	397	WYP	71,580,087	76,367,888	4,787,801
Utah	397	UT	209,739,126	220,451,113	10,711,987
Idaho	397	ID	42,565,330	43,505,285	939,955
Western Wyoming	397	WYU	13,702,519	13,341,805	(360,714)
Pre-merger Pacific	397	SG	655,748	477,746	(178,002)
Pre-merger Utah	397	SG	2,273,454	1,711,144	(562,311)
Post-merger	397	SG	118,805,520	103,346,376	(15,459,144)
Post-merger	397	SO	959,591,346	1,069,614,314	110,022,968
Post-merger	397	SG	-	-	-
Post-merger	397	SG	192,889	186,085	(6,804)
Customer Service	397	CN	238,683,088	237,089,255	(1,593,833)
Fuel Related	397	SE	2,813,277	2,544,783	(268,494)
Total General Plant			1,877,274,481	1,980,119,992	102,845,511
Mining Plant:					
Coal Mine	399	SE	1,822,901	1,822,901	-
Total Mining Plant			1,822,901	1,822,901	-
Intangible Plant:					
Pre-merger Utah	302	SG	477,596	435,357	(42,240)
Pre-merger Pacific	303	SG	-	-	-
California	303	CA	472,341	469,320	(3,021)
Customer Service	303	CN	-	(3,178,870)	(3,178,870)
Idaho	303	ID	4,356,591	4,351,609	(4,982)
Oregon	303	OR	4,601,718	4,597,089	(4,629)
Fuel Related	303	SE	-	-	-
Post-merger	303	SG	202,684,129	196,199,896	(6,484,233)
Post-merger	303	OTHER	-	-	-
Hydro Relicensing	302	SG-P	103,455,075	103,455,075	-
Hydro Relicensing	302	SG-U	10,024,217	9,717,774	(306,443)
General Office	303	SO	-	(13,908,637)	(13,908,637)
Utah	303	UT	7,444,448	7,436,155	(8,293)
Washington	303	WA	2,021,245	2,016,070	(5,175)
Eastern Wyoming	303	WYP	5,268,401	5,131,280	(137,121)
Western Wyoming	303	WYU	-	-	-
Total Intangible Plant			340,805,762	316,722,118	(24,083,644)
Total			**38,346,657,191**	**41,662,940,450**	**3,316,283,259**
			Ref. 8.5.4	**Ref. 8.5.36**	**Ref 8.5.1**

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
and Retirements

Description	FERC Account	2020P Factor Code	Adjusted EPIS Balance Jun 2025	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2025	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2025
Steam Production Plant:									
Pre-merger Pacific	312	SG	987,592,112	-	(181,436)	987,410,676	-	(181,436)	987,229,240
Pre-merger Utah	312	SG	1,014,704,747	-	(325,979)	1,014,378,767	-	(325,979)	1,014,052,788
Post-merger	312	SG	5,111,725,243	4,468,371	(3,178,251)	5,113,015,362	5,877,313	(3,178,251)	5,115,714,424
Post-merger	312	SG	1,266,851	-	-	1,266,851	-	-	1,266,851
Post-merger	312	SG	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-
Post-merger	312	SG	-	-	-	-	-	-	-
Total Steam Plant			7,115,288,953	4,468,371	(3,685,667)	7,116,071,657	5,877,313	(3,685,667)	7,118,263,303
Hydro Production Plant:									
Pre-merger Pacific	332	SG	173,759,313	-	(29,571)	173,729,743	-	(29,571)	173,700,172
Pre-merger Utah	332	SG	39,567,052	-	(19,142)	39,547,910	-	(19,142)	39,528,768
Post-merger	332	SG	13,047,000	-	-	13,047,000	-	-	13,047,000
Post-merger	332	SG-P	749,688,597	133,069	(213,901)	749,607,764	2,048,207	(213,901)	751,442,070
Post-merger	332	SG-U	168,988,088	(33,746)	(39,907)	168,914,435	(33,746)	(39,907)	168,840,782
Total Hydro Plant			1,145,050,050	99,323	(302,521)	1,144,846,852	2,014,461	(302,521)	1,146,558,793
Solar Production Plant:									
Oregon	338XP	OR	770,480	78,644	-	849,123	-	-	849,123
Utah	338XP	UT	561,017	(123)	-	560,893	(123)	-	560,770
Post-merger	338XP	SG	56,322	-	-	56,322	-	-	56,322
Post-merger	338XP	OTHER	-	-	-	-	-	-	-
Total Other Plant			1,387,818	78,521	-	1,466,339	(123)	-	1,466,216
Wind Production Plant:									
Oregon	338WP	OR	-	-	-	-	-	-	-
Utah	338WP	UT	-	-	-	-	-	-	-
Post-merger	338WP	SG	3,805,799,747	(49,251)	-	3,805,750,496	147,415	-	3,805,897,911
Post-merger	338WP	OTHER	-	-	-	-	-	-	-
Total Other Plant			3,805,799,747	(49,251)	-	3,805,750,496	147,415	-	3,805,897,911
Renewable Production Plant:									
Oregon	339RP	OR	-	-	-	-	-	-	-
Utah	339RP	UT	-	-	-	-	-	-	-
Post-merger	339RP	SG	157,826,749	13,715	-	157,840,464	13,715	-	157,854,179
Post-merger	339RP	OTHER	-	-	-	-	-	-	-
Total Other Plant			157,826,749	13,715	-	157,840,464	13,715	-	157,854,179
Other Production Plant:									
Pre-merger Pacific	343	SG	-	-	-	-	-	-	-
Pre-merger Utah	343	SG	235,129	-	-	235,129	-	-	235,129
Post-merger	343	SG	1,974,191,377	287,464	(2,338,824)	1,972,140,016	14,157	(2,338,824)	1,969,815,349
Post-merger	343	SG	88,883,413	-	(29,730)	88,853,683	-	(29,730)	88,823,953
Post-merger	343	SG	-	-	-	-	-	-	-
Total Other Plant			2,063,309,919	287,464	(2,368,554)	2,061,228,828	14,157	(2,368,554)	2,058,874,431

Transmission Plant:

PacifiCorp
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Pro Forma Plant Additions
and Retirements

Description	FERC Account	2020P Factor Code	Adjusted EPIS Balance Jun 2025	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2025	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2025
California	352	CA	-	-	-	-	-	-	-
Oregon	352	OR	-	(44,853)	-	(44,853)	(20,816)	-	(65,669)
Washington	352	WA	-	-	-	-	-	-	-
Wyoing	352	WYP	-	-	-	-	-	-	-
Wyoming	352	WYU	-	-	-	-	-	-	-
Utah	352	UT	-	-	-	-	-	-	-
Idaho	352	ID	-	-	-	-	-	-	-
System	355	OTHER	-	-	-	-	-	-	-
Pre-merger Pacific	355	SG	472,345,011	-	(169,652)	472,175,360	-	(169,652)	472,005,708
Pre-merger Utah	355	SG	604,989,761	-	(295,257)	604,694,504	-	(295,257)	604,399,247
Post-merger	355	SG	10,372,730,659	16,781,608	(1,336,358)	10,388,175,909	51,291,124	(1,336,358)	10,438,130,675
Total Transmission Plant			11,450,065,431	16,736,755	(1,801,267)	11,465,000,919	51,270,308	(1,801,267)	11,514,469,960
Distribution Plant:									
California	360-373	CA	590,906,802	3,111,224	(291,523)	593,726,503	8,529,017	(291,523)	601,963,997
Oregon	360-373	OR	3,137,515,987	15,646,060	(1,094,288)	3,152,067,758	15,222,595	(1,094,288)	3,166,196,065
Washington	360-373	WA	711,585,848	858,179	(229,053)	712,214,974	438,274	(229,053)	712,424,195
Eastern Wyoming	360-373	WYP	806,826,853	2,088,821	(278,411)	808,637,262	2,261,222	(278,411)	810,620,073
Utah	360-373	UT	4,430,786,259	47,496,386	(2,591,633)	4,475,691,012	55,954,772	(2,591,633)	4,529,054,150
Idaho	360-373	ID	497,264,321	1,984,240	(451,084)	498,797,477	2,747,633	(451,084)	501,094,026
Western Wyoming	360-373	WYU	166,489,437	-	(53,455)	166,435,982	-	(53,455)	166,382,527
System	360-373	SNPD	35,847,239	-	-	35,847,239	-	-	35,847,239
System	360-373	CN	10,802,634	-	-	10,802,634	-	-	10,802,634
System	360-373	SO	-	-	-	-	-	-	-
System	360-373	SG	-	-	-	-	-	-	-
System	360-373	OTHER	-	-	-	-	-	-	-
Total Distribution Plant			10,388,025,380	71,184,910	(4,989,448)	10,454,220,842	85,153,512	(4,989,448)	10,534,384,906
Energy Storage Plant									
California	387	CA	-	-	-	-	-	-	-
Oregon	387	OR	-	-	-	-	-	-	-
Washington	387	WA	-	-	-	-	-	-	-
Eastern Wyoming	387	WYP	-	-	-	-	-	-	-
Utah	387	UT	-	-	-	-	-	-	-
Idaho	387	ID	-	-	-	-	-	-	-
Western Wyoming	387	WYU	-	-	-	-	-	-	-
System	387	CN	-	-	-	-	-	-	-
System	387	SNPD	-	-	-	-	-	-	-
System	387	SG	-	-	-	-	-	-	-
System	387	SO	-	-	-	-	-	-	-
System	387	OTHER	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
and Retirements

Description	FERC Account	2020P Factor Code	Adjusted EPIS Balance Jun 2025	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2025	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2025
General Plant:									
California	397	CA	16,709,229	-	(50,275)	16,658,954	-	(50,275)	16,608,679
Oregon	397	OR	161,745,989	669,623	(709,086)	161,706,526	284,316	(709,086)	161,281,756
Washington	397	WA	38,216,878	-	(100,842)	38,116,037	-	(100,842)	38,015,195
Eastern Wyoming	397	WYP	71,580,087	23,068	(130,702)	71,472,453	712,004	(130,702)	72,053,755
Utah	397	UT	209,739,126	4,110,601	(530,751)	213,318,977	1,255,282	(530,751)	214,043,508
Idaho	397	ID	42,565,330	181,803	(87,666)	42,659,467	82,230	(87,666)	42,654,031
Western Wyoming	397	WYU	13,702,519	-	(17,563)	13,684,956	-	(17,563)	13,667,393
Pre-merger Pacific	397	SG	655,748	-	(8,667)	647,081	-	(8,667)	638,414
Pre-merger Utah	397	SG	2,273,454	-	(27,378)	2,246,076	-	(27,378)	2,218,697
Post-merger	397	SG	118,805,520	-	(752,692)	118,052,827	-	(752,692)	117,300,135
Post-merger	397	SO	959,591,346	(199,086)	(1,273,167)	958,119,093	444,279	(1,273,167)	957,290,205
Post-merger	397	SG	-	-	-	-	-	-	-
Post-merger	397	SG	192,889	-	(331)	192,557	-	(331)	192,226
Customer Service	397	CN	238,683,088	-	(77,602)	238,605,486	-	(77,602)	238,527,884
Fuel Related	397	SE	2,813,277	-	(13,073)	2,800,205	-	(13,073)	2,787,132
Total General Plant			1,877,274,481	4,786,010	(3,779,796)	1,878,280,695	2,778,112	(3,779,796)	1,877,279,011
Mining Plant:									
Coal Mine	399	SE	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Mining Plant			1,822,901	-	-	1,822,901	-	-	1,822,901
Intangible Plant:									
Pre-merger Utah	303	SG	477,596	-	(2,057)	475,540	-	(2,057)	473,483
Pre-merger Pacific	303	SG	-	-	-	-	-	-	-
California	303	CA	472,341	-	(147)	472,194	-	(147)	472,047
Customer Service	303	CN	-	-	(154,776)	(154,776)	-	(154,776)	(309,553)
Idaho	303	ID	4,356,591	-	(243)	4,356,348	-	(243)	4,356,106
Oregon	303	OR	4,601,718	-	(225)	4,601,493	-	(225)	4,601,267
Fuel Related	303	SE	-	-	-	-	-	-	-
Post-merger	303	SG	202,684,129	-	(315,712)	202,368,418	-	(315,712)	202,052,706
Post-merger	303	OTHER	-	-	-	-	-	-	-
Hydro Relicensing	303	SG-P	103,455,075	-	-	103,455,075	-	-	103,455,075
Hydro Relicensing	303	SG-U	10,024,217	-	(14,920)	10,009,296	-	(14,920)	9,994,376
General Office	303	SO	-	-	(677,200)	(677,200)	-	(677,200)	(1,354,399)
Utah	303	UT	7,444,448	-	(404)	7,444,044	-	(404)	7,443,640
Washington	303	WA	2,021,245	-	(252)	2,020,993	-	(252)	2,020,741
Eastern Wyoming	303	WYP	5,268,401	-	(6,676)	5,261,725	-	(6,676)	5,255,049
Western Wyoming	303	WYU	-	-	-	-	-	-	-
Total Intangible Plant			340,805,762	-	(1,172,612)	339,633,150	-	(1,172,612)	338,460,538
Total			**38,346,657,191**	97,605,818	(18,099,865)	38,426,163,144	147,268,871	(18,099,865)	38,555,332,149
			Ref 8.5.3						

PacifiCorp
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Pro Forma Plant Additions
and Retirements

Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Sep 2025	Capital Additions	Capital Retirements	Adjusted EPIS Balance Oct 2025	Capital Additions	Capital Retirements	Adjusted EPIS Balance Nov 2025
Steam Production Plant:											
Pre-merger Pacific	312	SG	-	(181,436)	987,047,804	-	(181,436)	986,866,368	-	(181,436)	986,684,932
Pre-merger Utah	312	SG	-	(325,979)	1,013,726,808	-	(325,979)	1,013,400,829	-	(325,979)	1,013,074,849
Post-merger	312	SG	2,456,322	(3,178,251)	5,114,992,494	2,281,571	(3,178,251)	5,114,095,814	4,448,765	(3,178,251)	5,115,366,327
Post-merger	312	SG	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Total Steam Plant			2,456,322	(3,685,667)	7,117,033,958	2,281,571	(3,685,667)	7,115,629,862	4,448,765	(3,685,667)	7,116,392,959
Hydro Production Plant:											
Pre-merger Pacific	332	SG	-	(29,571)	173,670,602	-	(29,571)	173,641,031	-	(29,571)	173,611,461
Pre-merger Utah	332	SG	-	(19,142)	39,509,627	-	(19,142)	39,490,485	-	(19,142)	39,471,344
Post-merger	332	SG	-	-	13,047,000	-	-	13,047,000	-	-	13,047,000
Post-merger	332	SG-P	1,730,724	(213,901)	752,958,892	650,461	(213,901)	753,395,452	11,658,916	(213,901)	764,840,466
Post-merger	332	SG-U	78,586	(39,907)	168,879,461	287,725	(39,907)	169,127,280	6,817,694	(39,907)	175,905,067
Total Hydro Plant			1,809,310	(302,521)	1,148,065,583	938,186	(302,521)	1,148,701,248	18,476,610	(302,521)	1,166,875,338
Solar Production Plant:											
Oregon	338XP	OR	-	-	849,123	-	-	849,123	-	-	849,123
Utah	338XP	UT	(123)	-	560,647	(123)	-	560,524	(123)	-	560,401
Post-merger	338XP	SG	-	-	56,322	-	-	56,322	-	-	56,322
Post-merger	338XP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			(123)	-	1,466,093	(123)	-	1,465,969	(123)	-	1,465,846
Wind Production Plant:											
Oregon	338WP	OR	-	-	-	-	-	-	-	-	-
Utah	338WP	UT	-	-	-	-	-	-	-	-	-
Post-merger	338WP	SG	3,224,693	-	3,809,122,604	(107,511)	-	3,809,015,093	(107,511)	-	3,808,907,582
Post-merger	338WP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			3,224,693	-	3,809,122,604	(107,511)	-	3,809,015,093	(107,511)	-	3,808,907,582
Renewable Production Plant:											
Oregon	339RP	OR	-	-	-	-	-	-	-	-	-
Utah	339RP	UT	-	-	-	-	-	-	-	-	-
Post-merger	339RP	SG	13,715	-	157,867,895	13,715	-	157,881,610	315,278	-	158,196,888
Post-merger	339RP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			13,715	-	157,867,895	13,715	-	157,881,610	315,278	-	158,196,888
Other Production Plant:											
Pre-merger Pacific	343	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	343	SG	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	343	SG	(46,568)	(2,338,824)	1,967,429,956	98,062	(2,338,824)	1,965,189,194	2,239,531	(2,338,824)	1,965,089,900
Post-merger	343	SG	-	(29,730)	88,794,223	-	(29,730)	88,764,493	-	(29,730)	88,734,763
Post-merger	343	SG	-	-	-	-	-	-	-	-	-
Total Other Plant			(46,568)	(2,368,554)	2,056,459,308	98,062	(2,368,554)	2,054,188,816	2,239,531	(2,368,554)	2,054,059,792

Transmission Plant:

PacifiCorp
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Pro Forma Plant Additions
and Retirements

Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Sep 2025	Capital Additions	Capital Retirements	Adjusted EPIS Balance Oct 2025	Capital Additions	Capital Retirements	Adjusted EPIS Balance Nov 2025
California	352	CA	-	-	-	-	-	-	-	-	-
Oregon	352	OR	(341,161)	-	(406,830)	13,363	-	(393,467)	-	-	(393,467)
Washington	352	WA	-	-	-	-	-	-	-	-	-
Wyoing	352	WYP	-	-	-	-	-	-	-	-	-
Wyoming	352	WYU	-	-	-	-	-	-	-	-	-
Utah	352	UT	-	-	-	-	-	-	-	-	-
Idaho	352	ID	-	-	-	-	-	-	-	-	-
System	355	OTHER	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	355	SG	-	(169,652)	471,836,056	-	(169,652)	471,666,404	-	(169,652)	471,496,752
Pre-merger Utah	355	SG	-	(295,257)	604,103,989	-	(295,257)	603,808,732	-	(295,257)	603,513,475
Post-merger	355	SG	92,102,332	(1,336,358)	10,528,896,649	66,923,506	(1,336,358)	10,594,483,797	47,240,040	(1,336,358)	10,640,387,478
Total Transmission Plant			91,761,171	(1,801,267)	11,604,429,864	66,936,869	(1,801,267)	11,669,565,466	47,240,040	(1,801,267)	11,715,004,239
Distribution Plant:											
California	360-373	CA	8,024,568	(291,523)	609,697,041	13,092,200	(291,523)	622,497,718	21,067,670	(291,523)	643,273,865
Oregon	360-373	OR	11,350,995	(1,094,288)	3,176,452,771	19,865,886	(1,094,288)	3,195,224,369	16,715,220	(1,094,288)	3,210,845,300
Washington	360-373	WA	1,262,941	(229,053)	713,458,083	1,988,440	(229,053)	715,217,470	563,501	(229,053)	715,551,917
Eastern Wyoming	360-373	WYP	4,894,968	(278,411)	815,236,630	4,155,329	(278,411)	819,113,548	3,933,303	(278,411)	822,768,439
Utah	360-373	UT	75,655,694	(2,591,633)	4,602,118,211	102,641,365	(2,591,633)	4,702,167,943	72,529,827	(2,591,633)	4,772,106,136
Idaho	360-373	ID	7,801,230	(451,084)	508,444,172	2,058,910	(451,084)	510,051,998	1,968,313	(451,084)	511,569,227
Western Wyoming	360-373	WYU	-	(53,455)	166,329,072	-	(53,455)	166,275,617	-	(53,455)	166,222,162
System	360-373	SNPD	-	-	35,847,239	-	-	35,847,239	-	-	35,847,239
System	360-373	CN	-	-	10,802,634	-	-	10,802,634	-	-	10,802,634
System	360-373	SO	-	-	-	-	-	-	-	-	-
System	360-373	SG	-	-	-	-	-	-	-	-	-
System	360-373	OTHER	-	-	-	-	-	-	-	-	-
Total Distribution Plant			108,990,396	(4,989,448)	10,638,385,853	143,802,129	(4,989,448)	10,777,198,534	116,777,833	(4,989,448)	10,888,986,919
Energy Storage Plant											
California	387	CA	-	-	-	-	-	-	-	-	-
Oregon	387	OR	-	-	-	-	-	-	-	-	-
Washington	387	WA	-	-	-	-	-	-	-	-	-
Eastern Wyoming	387	WYP	-	-	-	-	-	-	-	-	-
Utah	387	UT	-	-	-	-	-	-	-	-	-
Idaho	387	ID	-	-	-	-	-	-	-	-	-
Western Wyoming	387	WYU	-	-	-	-	-	-	-	-	-
System	387	CN	-	-	-	-	-	-	-	-	-
System	387	SNPD	-	-	-	-	-	-	-	-	-
System	387	SG	-	-	-	-	-	-	-	-	-
System	387	SO	-	-	-	-	-	-	-	-	-
System	387	OTHER	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-	-

PacifiCorp
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Pro Forma Plant Additions
and Retirements

Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Sep 2025	Capital Additions	Capital Retirements	Adjusted EPIS Balance Oct 2025	Capital Additions	Capital Retirements	Adjusted EPIS Balance Nov 2025
General Plant:											
California	397	CA	43,267	(50,275)	16,601,671	145,887	(50,275)	16,697,283	144,179	(50,275)	16,791,187
Oregon	397	OR	1,254,324	(709,086)	161,826,994	1,000,972	(709,086)	162,118,880	962,315	(709,086)	162,372,109
Washington	397	WA	89,498	(100,842)	38,003,851	238,678	(100,842)	38,141,687	235,263	(100,842)	38,276,109
Eastern Wyoming	397	WYP	280,445	(130,702)	72,203,498	278,197	(130,702)	72,350,992	278,224	(130,702)	72,498,513
Utah	397	UT	1,208,336	(530,751)	214,721,093	1,203,580	(530,751)	215,393,923	1,133,007	(530,751)	215,996,179
Idaho	397	ID	176,425	(87,666)	42,742,790	175,222	(87,666)	42,830,345	250,161	(87,666)	42,992,840
Western Wyoming	397	WYU	-	(17,563)	13,649,830	-	(17,563)	13,632,268	-	(17,563)	13,614,705
Pre-merger Pacific	397	SG	-	(8,667)	629,747	-	(8,667)	621,081	-	(8,667)	612,414
Pre-merger Utah	397	SG	-	(27,378)	2,191,319	-	(27,378)	2,163,941	-	(27,378)	2,136,562
Post-merger	397	SG	-	(752,692)	116,547,442	-	(752,692)	115,794,750	-	(752,692)	115,042,058
Post-merger	397	SO	8,182,084	(1,273,167)	964,199,122	6,304,810	(1,273,167)	969,230,765	11,600,679	(1,273,167)	979,558,277
Post-merger	397	SG	-	-	-	-	-	-	-	-	-
Post-merger	397	SG	-	(331)	191,895	-	(331)	191,563	-	(331)	191,232
Customer Service	397	CN	-	(77,602)	238,450,281	-	(77,602)	238,372,679	-	(77,602)	238,295,077
Fuel Related	397	SE	-	(13,073)	2,774,059	-	(13,073)	2,760,986	-	(13,073)	2,747,914
Total General Plant			11,234,378	(3,779,796)	1,884,733,593	9,347,346	(3,779,796)	1,890,301,143	14,603,828	(3,779,796)	1,901,125,175
Mining Plant:											
Coal Mine	399	SE	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Mining Plant			-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Intangible Plant:											
Pre-merger Utah	303	SG	-	(2,057)	471,427	-	(2,057)	469,370	-	(2,057)	467,313
Pre-merger Pacific	303	SG	-	-	-	-	-	-	-	-	-
California	303	CA	-	(147)	471,900	-	(147)	471,753	-	(147)	471,605
Customer Service	303	CN	-	(154,776)	(464,329)	-	(154,776)	(619,106)	-	(154,776)	(773,882)
Idaho	303	ID	-	(243)	4,355,863	-	(243)	4,355,621	-	(243)	4,355,378
Oregon	303	OR	-	(225)	4,601,042	-	(225)	4,600,817	-	(225)	4,600,591
Fuel Related	303	SE	-	-	-	-	-	-	-	-	-
Post-merger	303	SG	-	(315,712)	201,736,994	-	(315,712)	201,421,282	-	(315,712)	201,105,571
Post-merger	303	OTHER	-	-	-	-	-	-	-	-	-
Hydro Relicensing	303	SG-P	-	-	103,455,075	-	-	103,455,075	-	-	103,455,075
Hydro Relicensing	303	SG-U	-	(14,920)	9,979,455	-	(14,920)	9,964,535	-	(14,920)	9,949,615
General Office	303	SO	-	(677,200)	(2,031,599)	-	(677,200)	(2,708,798)	-	(677,200)	(3,385,998)
Utah	303	UT	-	(404)	7,443,237	-	(404)	7,442,833	-	(404)	7,442,429
Washington	303	WA	-	(252)	2,020,489	-	(252)	2,020,237	-	(252)	2,019,985
Eastern Wyoming	303	WYP	-	(6,676)	5,248,373	-	(6,676)	5,241,696	-	(6,676)	5,235,020
Western Wyoming	303	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant			-	(1,172,612)	337,287,926	-	(1,172,612)	336,115,314	-	(1,172,612)	334,942,702
Total			219,443,294	(18,099,865)	38,756,675,577	223,310,244	(18,099,865)	38,961,885,956	203,994,251	(18,099,865)	39,147,780,342

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Dec 2025	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jan 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Feb 2026
Steam Production Plant:											
Pre-merger Pacific	312	SG	-	(181,436)	986,503,495	-	(181,436)	986,322,059	-	(181,436)	986,140,623
Pre-merger Utah	312	SG	-	(325,979)	1,012,748,870	-	(325,979)	1,012,422,891	-	(325,979)	1,012,096,911
Post-merger	312	SG	9,121,317	(3,178,251)	5,121,309,393	1,208,163	(3,178,251)	5,119,339,305	1,408,748	(3,178,251)	5,117,569,801
Post-merger	312	SG	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Total Steam Plant			9,121,317	(3,685,667)	7,121,828,609	1,208,163	(3,685,667)	7,119,351,106	1,408,748	(3,685,667)	7,117,074,187
Hydro Production Plant:											
Pre-merger Pacific	332	SG	-	(29,571)	173,581,890	-	(29,571)	173,552,320	-	(29,571)	173,522,749
Pre-merger Utah	332	SG	-	(19,142)	39,452,202	-	(19,142)	39,433,060	-	(19,142)	39,413,919
Post-merger	332	SG	-	-	13,047,000	-	-	13,047,000	-	-	13,047,000
Post-merger	332	SG-P	3,548,791	(213,901)	768,175,356	11,755,305	(213,901)	779,716,760	11,339,383	(213,901)	790,842,241
Post-merger	332	SG-U	4,094,169	(39,907)	179,959,329	(53,441)	(39,907)	179,865,982	(53,441)	(39,907)	179,772,634
Total Hydro Plant			7,642,961	(302,521)	1,174,215,778	11,701,865	(302,521)	1,185,615,122	11,285,942	(302,521)	1,196,598,544
Solar Production Plant:											
Oregon	338XP	OR	-	-	849,123	-	-	849,123	-	-	849,123
Utah	338XP	UT	(123)	-	560,278	(123)	-	560,154	(123)	-	560,031
Post-merger	338XP	SG	-	-	56,322	-	-	56,322	-	-	56,322
Post-merger	338XP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			(123)	-	1,465,723	(123)	-	1,465,600	(123)	-	1,465,477
Wind Production Plant:											
Oregon	338WP	OR	-	-	-	-	-	-	-	-	-
Utah	338WP	UT	-	-	-	-	-	-	-	-	-
Post-merger	338WP	SG	8,834,362	-	3,817,741,944	(107,511)	-	3,817,634,433	(107,511)	-	3,817,526,922
Post-merger	338WP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			8,834,362	-	3,817,741,944	(107,511)	-	3,817,634,433	(107,511)	-	3,817,526,922
Renewable Production Plant:											
Oregon	339RP	OR	-	-	-	-	-	-	-	-	-
Utah	339RP	UT	-	-	-	-	-	-	-	-	-
Post-merger	339RP	SG	13,715	-	158,210,604	14,174	-	158,224,778	14,174	-	158,238,952
Post-merger	339RP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			13,715	-	158,210,604	14,174	-	158,224,778	14,174	-	158,238,952
Other Production Plant:											
Pre-merger Pacific	343	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	343	SG	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	343	SG	6,177,280	(2,338,824)	1,968,928,355	19,671	(2,338,824)	1,966,609,202	(2,984)	(2,338,824)	1,964,267,393
Post-merger	343	SG	-	(29,730)	88,705,033	-	(29,730)	88,675,303	-	(29,730)	88,645,573
Post-merger	343	SG	-	-	-	-	-	-	-	-	-
Total Other Plant			6,177,280	(2,368,554)	2,057,868,518	19,671	(2,368,554)	2,055,519,635	(2,984)	(2,368,554)	2,053,148,096

Transmission Plant:

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Dec 2025	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jan 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Feb 2026
California	352	CA	-	-	-	-	-	-	-	-	-
Oregon	352	OR	1,623,183	-	1,229,716	12,432,442	-	13,662,158	2,541,485	-	16,203,644
Washington	352	WA	-	-	-	-	-	-	-	-	-
Wyoing	352	WYP	-	-	-	-	-	-	-	-	-
Wyoming	352	WYU	-	-	-	-	-	-	-	-	-
Utah	352	UT	-	-	-	-	-	-	-	-	-
Idaho	352	ID	-	-	-	-	-	-	-	-	-
System	355	OTHER	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	355	SG	-	(169,652)	471,327,100	-	(169,652)	471,157,448	-	(169,652)	470,987,797
Pre-merger Utah	355	SG	-	(295,257)	603,218,218	-	(295,257)	602,922,961	-	(295,257)	602,627,704
Post-merger	355	SG	77,063,894	(1,336,358)	10,716,115,014	9,958,968	(1,336,358)	10,724,737,624	33,358,810	(1,336,358)	10,756,760,076
Total Transmission Plant			78,687,076	(1,801,267)	11,791,890,048	22,391,411	(1,801,267)	11,812,480,192	35,900,295	(1,801,267)	11,846,579,221
Distribution Plant:											
California	360-373	CA	18,205,798	(291,523)	661,188,139	3,501,237	(291,523)	664,397,853	4,941,188	(291,523)	669,047,518
Oregon	360-373	OR	11,673,215	(1,094,288)	3,221,424,227	4,541,561	(1,094,288)	3,224,871,500	198,468,123	(1,094,288)	3,422,245,334
Washington	360-373	WA	2,552,731	(229,053)	717,875,595	1,076,984	(229,053)	718,723,526	1,010,469	(229,053)	719,504,942
Eastern Wyoming	360-373	WYP	35,907,896	(278,411)	858,397,924	2,409,763	(278,411)	860,529,275	2,617,591	(278,411)	862,868,455
Utah	360-373	UT	100,046,016	(2,591,633)	4,869,560,519	14,630,353	(2,591,633)	4,881,599,238	45,781,163	(2,591,633)	4,924,788,768
Idaho	360-373	ID	7,951,748	(451,084)	519,069,890	1,812,877	(451,084)	520,431,683	2,023,822	(451,084)	522,004,421
Western Wyoming	360-373	WYU	-	(53,455)	166,168,707	-	(53,455)	166,115,252	-	(53,455)	166,061,797
System	360-373	SNPD	-	-	35,847,239	-	-	35,847,239	-	-	35,847,239
System	360-373	CN	-	-	10,802,634	-	-	10,802,634	-	-	10,802,634
System	360-373	SO	-	-	-	-	-	-	-	-	-
System	360-373	SG	-	-	-	-	-	-	-	-	-
System	360-373	OTHER	-	-	-	-	-	-	-	-	-
Total Distribution Plant			176,337,404	(4,989,448)	11,060,334,874	27,972,775	(4,989,448)	11,083,318,201	254,842,357	(4,989,448)	11,333,171,110
Energy Storage Plant											
California	387	CA	-	-	-	-	-	-	-	-	-
Oregon	387	OR	-	-	-	-	-	-	-	-	-
Washington	387	WA	-	-	-	-	-	-	-	-	-
Eastern Wyoming	387	WYP	-	-	-	-	-	-	-	-	-
Utah	387	UT	-	-	-	-	-	-	-	-	-
Idaho	387	ID	-	-	-	-	-	-	-	-	-
Western Wyoming	387	WYU	-	-	-	-	-	-	-	-	-
System	387	CN	-	-	-	-	-	-	-	-	-
System	387	SNPD	-	-	-	-	-	-	-	-	-
System	387	SG	-	-	-	-	-	-	-	-	-
System	387	SO	-	-	-	-	-	-	-	-	-
System	387	OTHER	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-	-

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Dec 2025	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jan 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Feb 2026
General Plant:											
California	397	CA	153,095	(50,275)	16,894,007	9,935	(50,275)	16,853,667	10,085	(50,275)	16,813,477
Oregon	397	OR	1,372,141	(709,086)	163,035,164	133,285	(709,086)	162,459,363	136,277	(709,086)	161,886,554
Washington	397	WA	253,096	(100,842)	38,428,363	19,445	(100,842)	38,346,966	19,745	(100,842)	38,265,869
Eastern Wyoming	397	WYP	280,544	(130,702)	72,648,355	318,040	(130,702)	72,835,692	290,054	(130,702)	72,995,043
Utah	397	UT	1,137,637	(530,751)	216,603,066	703,409	(530,751)	216,775,724	648,967	(530,751)	216,893,940
Idaho	397	ID	250,957	(87,666)	43,156,131	113,684	(87,666)	43,182,148	104,733	(87,666)	43,199,215
Western Wyoming	397	WYU	-	(17,563)	13,597,142	-	(17,563)	13,579,579	-	(17,563)	13,562,016
Pre-merger Pacific	397	SG	-	(8,667)	603,747	-	(8,667)	595,080	-	(8,667)	586,414
Pre-merger Utah	397	SG	-	(27,378)	2,109,184	-	(27,378)	2,081,805	-	(27,378)	2,054,427
Post-merger	397	SG	-	(752,692)	114,289,365	-	(752,692)	113,536,673	-	(752,692)	112,783,980
Post-merger	397	SO	17,415,841	(1,273,167)	995,700,951	3,420,513	(1,273,167)	997,848,297	2,746,075	(1,273,167)	999,321,205
Post-merger	397	SG	-	-	-	-	-	-	-	-	-
Post-merger	397	SG	-	(331)	190,901	-	(331)	190,570	-	(331)	190,238
Customer Service	397	CN	-	(77,602)	238,217,474	-	(77,602)	238,139,872	-	(77,602)	238,062,269
Fuel Related	397	SE	-	(13,073)	2,734,841	-	(13,073)	2,721,768	-	(13,073)	2,708,695
Total General Plant			20,863,311	(3,779,796)	1,918,208,690	4,718,311	(3,779,796)	1,919,147,205	3,955,936	(3,779,796)	1,919,323,344
Mining Plant:											
Coal Mine	399	SE	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Mining Plant			-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Intangible Plant:											
Pre-merger Utah	303	SG	-	(2,057)	465,257	-	(2,057)	463,200	-	(2,057)	461,143
Pre-merger Pacific	303	SG	-	-	-	-	-	-	-	-	-
California	303	CA	-	(147)	471,458	-	(147)	471,311	-	(147)	471,164
Customer Service	303	CN	-	(154,776)	(928,659)	-	(154,776)	(1,083,435)	-	(154,776)	(1,238,212)
Idaho	303	ID	-	(243)	4,355,135	-	(243)	4,354,893	-	(243)	4,354,650
Oregon	303	OR	-	(225)	4,600,366	-	(225)	4,600,140	-	(225)	4,599,915
Fuel Related	303	SE	-	-	-	-	-	-	-	-	-
Post-merger	303	SG	-	(315,712)	200,789,859	-	(315,712)	200,474,147	-	(315,712)	200,158,436
Post-merger	303	OTHER	-	-	-	-	-	-	-	-	-
Hydro Relicensing	303	SG-P	-	-	103,455,075	-	-	103,455,075	-	-	103,455,075
Hydro Relicensing	303	SG-U	-	(14,920)	9,934,694	-	(14,920)	9,919,774	-	(14,920)	9,904,853
General Office	303	SO	-	(677,200)	(4,063,197)	-	(677,200)	(4,740,397)	-	(677,200)	(5,417,596)
Utah	303	UT	-	(404)	7,442,025	-	(404)	7,441,622	-	(404)	7,441,218
Washington	303	WA	-	(252)	2,019,733	-	(252)	2,019,481	-	(252)	2,019,229
Eastern Wyoming	303	WYP	-	(6,676)	5,228,344	-	(6,676)	5,221,667	-	(6,676)	5,214,991
Western Wyoming	303	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant			-	(1,172,612)	333,770,090	-	(1,172,612)	332,597,479	-	(1,172,612)	331,424,867
Total			307,677,304	(18,099,865)	39,437,357,780	67,918,736	(18,099,865)	39,487,176,651	307,296,833	(18,099,865)	39,776,373,619

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Mar 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Apr 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance May 2026
Steam Production Plant:											
Pre-merger Pacific	312	SG	-	(181,436)	985,959,187	-	(181,436)	985,777,751	-	(181,436)	985,596,315
Pre-merger Utah	312	SG	-	(325,979)	1,011,770,932	-	(325,979)	1,011,444,952	-	(325,979)	1,011,118,973
Post-merger	312	SG	3,385,228	(3,178,251)	5,117,776,778	17,913,224	(3,178,251)	5,132,511,750	25,472,970	(3,178,251)	5,154,806,469
Post-merger	312	SG	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Total Steam Plant			3,385,228	(3,685,667)	7,116,773,747	17,913,224	(3,685,667)	7,131,001,305	25,472,970	(3,685,667)	7,152,788,608
Hydro Production Plant:											
Pre-merger Pacific	332	SG	-	(29,571)	173,493,179	-	(29,571)	173,463,608	-	(29,571)	173,434,037
Pre-merger Utah	332	SG	-	(19,142)	39,394,777	-	(19,142)	39,375,636	-	(19,142)	39,356,494
Post-merger	332	SG	-	-	13,047,000	-	-	13,047,000	-	-	13,047,000
Post-merger	332	SG-P	103,813	(213,901)	790,732,153	173,443	(213,901)	790,691,695	1,167,753	(213,901)	791,645,546
Post-merger	332	SG-U	(53,441)	(39,907)	179,679,287	157,559	(39,907)	179,796,939	(53,441)	(39,907)	179,703,591
Total Hydro Plant			50,372	(302,521)	1,196,346,396	331,002	(302,521)	1,196,374,878	1,114,312	(302,521)	1,197,186,669
Solar Production Plant:											
Oregon	338XP	OR	-	-	849,123	-	-	849,123	-	-	849,123
Utah	338XP	UT	(123)	-	559,908	(123)	-	559,785	(123)	-	559,662
Post-merger	338XP	SG	-	-	56,322	-	-	56,322	-	-	56,322
Post-merger	338XP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			(123)	-	1,465,354	(123)	-	1,465,230	(123)	-	1,465,107
Wind Production Plant:											
Oregon	338WP	OR	-	-	-	-	-	-	-	-	-
Utah	338WP	UT	-	-	-	-	-	-	-	-	-
Post-merger	338WP	SG	2,589,333	-	3,820,116,255	(107,511)	-	3,820,008,743	(107,511)	-	3,819,901,232
Post-merger	338WP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			2,589,333	-	3,820,116,255	(107,511)	-	3,820,008,743	(107,511)	-	3,819,901,232
Renewable Production Plant:											
Oregon	339RP	OR	-	-	-	-	-	-	-	-	-
Utah	339RP	UT	-	-	-	-	-	-	-	-	-
Post-merger	339RP	SG	14,174	-	158,253,126	641,478	-	158,894,604	14,174	-	158,908,778
Post-merger	339RP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			14,174	-	158,253,126	641,478	-	158,894,604	14,174	-	158,908,778
Other Production Plant:											
Pre-merger Pacific	343	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	343	SG	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	343	SG	(2,984)	(2,338,824)	1,961,925,584	31,168,948	(2,338,824)	1,990,755,708	669,454	(2,338,824)	1,989,086,337
Post-merger	343	SG	-	(29,730)	88,615,843	-	(29,730)	88,586,113	-	(29,730)	88,556,383
Post-merger	343	SG	-	-	-	-	-	-	-	-	-
Total Other Plant			(2,984)	(2,368,554)	2,050,776,557	31,168,948	(2,368,554)	2,079,576,950	669,454	(2,368,554)	2,077,877,849

Transmission Plant:

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Mar 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Apr 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance May 2026
California	352	CA	-	-	-	-	-	-	-	-	-
Oregon	352	OR	2,550,386	-	18,754,030	43,684,671	-	62,438,701	113,634,884	-	176,073,585
Washington	352	WA	-	-	-	-	-	-	-	-	-
Wyoing	352	WYP	-	-	-	-	-	-	-	-	-
Wyoming	352	WYU	-	-	-	-	-	-	-	-	-
Utah	352	UT	-	-	-	-	-	-	-	-	-
Idaho	352	ID	-	-	-	-	-	-	-	-	-
System	355	OTHER	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	355	SG	-	(169,652)	470,818,145	-	(169,652)	470,648,493	-	(169,652)	470,478,841
Pre-merger Utah	355	SG	-	(295,257)	602,332,447	-	(295,257)	602,037,190	-	(295,257)	601,741,933
Post-merger	355	SG	14,654,037	(1,336,358)	10,770,077,755	17,602,090	(1,336,358)	10,786,343,487	32,326,905	(1,336,358)	10,817,334,034
Total Transmission Plant			17,204,424	(1,801,267)	11,861,982,377	61,286,760	(1,801,267)	11,921,467,871	145,961,789	(1,801,267)	12,065,628,393
Distribution Plant:											
California	360-373	CA	15,273,565	(291,523)	684,029,560	3,597,981	(291,523)	687,336,017	23,431,038	(291,523)	710,475,532
Oregon	360-373	OR	8,894,289	(1,094,288)	3,430,045,335	9,792,774	(1,094,288)	3,438,743,820	10,686,842	(1,094,288)	3,448,336,374
Washington	360-373	WA	2,254,763	(229,053)	721,530,652	2,481,288	(229,053)	723,782,887	9,850,100	(229,053)	733,403,934
Eastern Wyoming	360-373	WYP	3,103,603	(278,411)	865,693,647	3,462,339	(278,411)	868,877,574	12,321,188	(278,411)	880,920,351
Utah	360-373	UT	18,662,422	(2,591,633)	4,940,859,557	17,702,534	(2,591,633)	4,955,970,458	84,368,194	(2,591,633)	5,037,747,019
Idaho	360-373	ID	2,424,719	(451,084)	523,978,055	2,454,196	(451,084)	525,981,167	4,323,070	(451,084)	529,853,153
Western Wyoming	360-373	WYU	-	(53,455)	166,008,342	-	(53,455)	165,954,887	-	(53,455)	165,901,432
System	360-373	SNPD	-	-	35,847,239	1,883,228	-	37,730,467	-	-	37,730,467
System	360-373	CN	-	-	10,802,634	-	-	10,802,634	-	-	10,802,634
System	360-373	SO	-	-	-	-	-	-	-	-	-
System	360-373	SG	-	-	-	-	-	-	-	-	-
System	360-373	OTHER	-	-	-	-	-	-	-	-	-
Total Distribution Plant			50,613,360	(4,989,448)	11,378,795,021	41,374,340	(4,989,448)	11,415,179,913	144,980,433	(4,989,448)	11,555,170,897
Energy Storage Plant											
California	387	CA	-	-	-	-	-	-	-	-	-
Oregon	387	OR	-	-	-	-	-	-	-	-	-
Washington	387	WA	-	-	-	-	-	-	-	-	-
Eastern Wyoming	387	WYP	-	-	-	-	-	-	-	-	-
Utah	387	UT	-	-	-	-	-	-	-	-	-
Idaho	387	ID	-	-	-	-	-	-	-	-	-
Western Wyoming	387	WYU	-	-	-	-	-	-	-	-	-
System	387	CN	-	-	-	-	-	-	-	-	-
System	387	SNPD	-	-	-	-	-	-	-	-	-
System	387	SG	-	-	-	-	-	-	-	-	-
System	387	SO	-	-	-	-	-	-	-	-	-
System	387	OTHER	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-	-

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Mar 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Apr 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance May 2026
General Plant:											
California	397	CA	11,923	(50,275)	16,775,126	13,581	(50,275)	16,738,431	20,701	(50,275)	16,708,857
Oregon	397	OR	167,469	(709,086)	161,344,937	189,556	(709,086)	160,825,408	316,639	(709,086)	160,432,961
Washington	397	WA	23,421	(100,842)	38,188,449	104,672	(100,842)	38,192,279	40,976	(100,842)	38,132,414
Eastern Wyoming	397	WYP	296,039	(130,702)	73,160,380	673,398	(130,702)	73,703,075	301,898	(130,702)	73,874,271
Utah	397	UT	672,075	(530,751)	217,035,264	708,337	(530,751)	217,212,851	800,096	(530,751)	217,482,196
Idaho	397	ID	107,049	(87,666)	43,218,597	105,799	(87,666)	43,236,730	109,174	(87,666)	43,258,238
Western Wyoming	397	WYU	-	(17,563)	13,544,453	-	(17,563)	13,526,890	-	(17,563)	13,509,327
Pre-merger Pacific	397	SG	-	(8,667)	577,747	-	(8,667)	569,080	-	(8,667)	560,413
Pre-merger Utah	397	SG	-	(27,378)	2,027,049	-	(27,378)	1,999,670	-	(27,378)	1,972,292
Post-merger	397	SG	-	(752,692)	112,031,288	-	(752,692)	111,278,596	-	(752,692)	110,525,903
Post-merger	397	SO	3,086,536	(1,273,167)	1,001,134,574	3,300,067	(1,273,167)	1,003,161,474	4,099,986	(1,273,167)	1,005,988,293
Post-merger	397	SG	-	-	-	-	-	-	-	-	-
Post-merger	397	SG	-	(331)	189,907	-	(331)	189,576	-	(331)	189,244
Customer Service	397	CN	-	(77,602)	237,984,667	-	(77,602)	237,907,065	-	(77,602)	237,829,462
Fuel Related	397	SE	-	(13,073)	2,695,623	-	(13,073)	2,682,550	-	(13,073)	2,669,477
Total General Plant			4,364,513	(3,779,796)	1,919,908,061	5,095,410	(3,779,796)	1,921,223,675	5,689,471	(3,779,796)	1,923,133,349
Mining Plant:											
Coal Mine	399	SE	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Mining Plant			-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Intangible Plant:											
Pre-merger Utah	303	SG	-	(2,057)	459,087	-	(2,057)	457,030	-	(2,057)	454,974
Pre-merger Pacific	303	SG	-	-	-	-	-	-	-	-	-
California	303	CA	-	(147)	471,017	-	(147)	470,870	-	(147)	470,723
Customer Service	303	CN	-	(154,776)	(1,392,988)	-	(154,776)	(1,547,765)	-	(154,776)	(1,702,541)
Idaho	303	ID	-	(243)	4,354,408	-	(243)	4,354,165	-	(243)	4,353,923
Oregon	303	OR	-	(225)	4,599,690	-	(225)	4,599,464	-	(225)	4,599,239
Fuel Related	303	SE	-	-	-	-	-	-	-	-	-
Post-merger	303	SG	-	(315,712)	199,842,724	-	(315,712)	199,527,012	-	(315,712)	199,211,300
Post-merger	303	OTHER	-	-	-	-	-	-	-	-	-
Hydro Relicensing	303	SG-P	-	-	103,455,075	-	-	103,455,075	-	-	103,455,075
Hydro Relicensing	303	SG-U	-	(14,920)	9,889,933	-	(14,920)	9,875,013	-	(14,920)	9,860,092
General Office	303	SO	-	(677,200)	(6,094,796)	-	(677,200)	(6,771,996)	-	(677,200)	(7,449,195)
Utah	303	UT	-	(404)	7,440,814	-	(404)	7,440,410	-	(404)	7,440,006
Washington	303	WA	-	(252)	2,018,977	-	(252)	2,018,725	-	(252)	2,018,473
Eastern Wyoming	303	WYP	-	(6,676)	5,208,315	-	(6,676)	5,201,638	-	(6,676)	5,194,962
Western Wyoming	303	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant			-	(1,172,612)	330,252,255	-	(1,172,612)	329,079,643	-	(1,172,612)	327,907,031
Total			78,218,296	(18,099,865)	39,836,492,050	157,703,528	(18,099,865)	39,976,095,713	323,794,968	(18,099,865)	40,281,790,815

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Steam Production Plant:											
Pre-merger Pacific	312	SG	-	(181,436)	985,414,878	-	(181,436)	985,233,442	-	(181,436)	985,052,006
Pre-merger Utah	312	SG	-	(325,979)	1,010,792,993	-	(325,979)	1,010,467,014	-	(325,979)	1,010,141,035
Post-merger	312	SG	24,604,453	(3,178,251)	5,176,232,671	6,735,238	(3,178,251)	5,179,789,657	1,031,632	(3,178,251)	5,177,643,038
Post-merger	312	SG	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Total Steam Plant			24,604,453	(3,685,667)	7,173,707,394	6,735,238	(3,685,667)	7,176,756,964	1,031,632	(3,685,667)	7,174,102,929
Hydro Production Plant:											
Pre-merger Pacific	332	SG	-	(29,571)	173,404,467	-	(29,571)	173,374,896	-	(29,571)	173,345,326
Pre-merger Utah	332	SG	-	(19,142)	39,337,352	-	(19,142)	39,318,211	-	(19,142)	39,299,069
Post-merger	332	SG	-	-	13,047,000	-	-	13,047,000	-	-	13,047,000
Post-merger	332	SG-P	1,388,992	(213,901)	792,820,637	894,282	(213,901)	793,501,018	725,713	(213,901)	794,012,830
Post-merger	332	SG-U	2,754,893	(39,907)	182,418,578	(53,441)	(39,907)	182,325,230	(53,441)	(39,907)	182,231,883
Total Hydro Plant			4,143,886	(302,521)	1,201,028,035	840,842	(302,521)	1,201,566,356	672,272	(302,521)	1,201,936,108
Solar Production Plant:											
Oregon	338XP	OR	-	-	849,123	-	-	849,123	-	-	849,123
Utah	338XP	UT	(123)	-	559,539	(123)	-	559,416	(123)	-	559,292
Post-merger	338XP	SG	-	-	56,322	-	-	56,322	-	-	56,322
Post-merger	338XP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			(123)	-	1,464,984	(123)	-	1,464,861	(123)	-	1,464,738
Wind Production Plant:											
Oregon	338WP	OR	-	-	-	-	-	-	-	-	-
Utah	338WP	UT	-	-	-	-	-	-	-	-	-
Post-merger	338WP	SG	2,589,333	-	3,822,490,565	(107,511)	-	3,822,383,054	(107,511)	-	3,822,275,542
Post-merger	338WP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			2,589,333	-	3,822,490,565	(107,511)	-	3,822,383,054	(107,511)	-	3,822,275,542
Renewable Production Plant:											
Oregon	339RP	OR	-	-	-	-	-	-	-	-	-
Utah	339RP	UT	-	-	-	-	-	-	-	-	-
Post-merger	339RP	SG	14,174	-	158,922,953	14,174	-	158,937,127	14,174	-	158,951,301
Post-merger	339RP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			14,174	-	158,922,953	14,174	-	158,937,127	14,174	-	158,951,301
Other Production Plant:											
Pre-merger Pacific	343	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	343	SG	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	343	SG	786,594	(2,338,824)	1,987,534,106	158,133	(2,338,824)	1,985,353,414	(2,984)	(2,338,824)	1,983,011,605
Post-merger	343	SG	39,177	(29,730)	88,565,830	-	(29,730)	88,536,100	-	(29,730)	88,506,370
Post-merger	343	SG	-	-	-	-	-	-	-	-	-
Total Other Plant			825,771	(2,368,554)	2,076,335,066	158,133	(2,368,554)	2,074,124,644	(2,984)	(2,368,554)	2,071,753,105

Transmission Plant:

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jun 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jul 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Aug 2026
California	352	CA	-	-	-	-	-	-	-	-	-
Oregon	352	OR	582,547	-	176,656,132	2,702,355	-	179,358,487	6,677,883	-	186,036,370
Washington	352	WA	-	-	-	-	-	-	-	-	-
Wyoing	352	WYP	-	-	-	-	-	-	-	-	-
Wyoming	352	WYU	-	-	-	-	-	-	-	-	-
Utah	352	UT	-	-	-	-	-	-	-	-	-
Idaho	352	ID	-	-	-	-	-	-	-	-	-
System	355	OTHER	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	355	SG	-	(169,652)	470,309,189	-	(169,652)	470,139,537	-	(169,652)	469,969,885
Pre-merger Utah	355	SG	-	(295,257)	601,446,676	-	(295,257)	601,151,419	-	(295,257)	600,856,162
Post-merger	355	SG	47,524,839	(1,336,358)	10,863,522,515	22,412,214	(1,336,358)	10,884,598,371	81,306,044	(1,336,358)	10,964,568,057
Total Transmission Plant			48,107,386	(1,801,267)	12,111,934,512	25,114,569	(1,801,267)	12,135,247,814	87,983,927	(1,801,267)	12,221,430,474
Distribution Plant:											
California	360-373	CA	27,699,941	(291,523)	737,883,950	20,591,737	(291,523)	758,184,164	2,352,247	(291,523)	760,244,887
Oregon	360-373	OR	27,816,444	(1,094,288)	3,475,058,530	11,831,683	(1,094,288)	3,485,795,924	9,636,116	(1,094,288)	3,494,337,752
Washington	360-373	WA	2,637,122	(229,053)	735,812,004	3,077,013	(229,053)	738,659,963	2,371,885	(229,053)	740,802,795
Eastern Wyoming	360-373	WYP	5,054,595	(278,411)	885,696,535	5,076,850	(278,411)	890,494,974	6,069,498	(278,411)	896,286,060
Utah	360-373	UT	23,801,408	(2,591,633)	5,058,956,793	38,006,312	(2,591,633)	5,094,371,472	26,159,104	(2,591,633)	5,117,938,942
Idaho	360-373	ID	2,813,105	(451,084)	532,215,175	2,554,514	(451,084)	534,318,605	3,024,708	(451,084)	536,892,229
Western Wyoming	360-373	WYU	-	(53,455)	165,847,977	-	(53,455)	165,794,523	-	(53,455)	165,741,068
System	360-373	SNPD	-	-	37,730,467	-	-	37,730,467	-	-	37,730,467
System	360-373	CN	-	-	10,802,634	-	-	10,802,634	-	-	10,802,634
System	360-373	SO	-	-	-	-	-	-	-	-	-
System	360-373	SG	-	-	-	-	-	-	-	-	-
System	360-373	OTHER	-	-	-	-	-	-	-	-	-
Total Distribution Plant			89,822,617	(4,989,448)	11,640,004,065	81,138,109	(4,989,448)	11,716,152,726	49,613,557	(4,989,448)	11,760,776,835
Energy Storage Plant											
California	387	CA	-	-	-	-	-	-	-	-	-
Oregon	387	OR	-	-	-	-	-	-	-	-	-
Washington	387	WA	-	-	-	-	-	-	-	-	-
Eastern Wyoming	387	WYP	-	-	-	-	-	-	-	-	-
Utah	387	UT	-	-	-	-	-	-	-	-	-
Idaho	387	ID	-	-	-	-	-	-	-	-	-
Western Wyoming	387	WYU	-	-	-	-	-	-	-	-	-
System	387	CN	-	-	-	-	-	-	-	-	-
System	387	SNPD	-	-	-	-	-	-	-	-	-
System	387	SG	-	-	-	-	-	-	-	-	-
System	387	SO	-	-	-	-	-	-	-	-	-
System	387	OTHER	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-	-

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jun 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jul 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Aug 2026
General Plant:											
California	397	CA	15,543	(50,275)	16,674,125	33,793	(50,275)	16,657,643	22,589	(50,275)	16,629,957
Oregon	397	OR	228,972	(709,086)	159,952,846	539,190	(709,086)	159,782,950	349,748	(709,086)	159,423,612
Washington	397	WA	30,661	(100,842)	38,062,233	67,159	(100,842)	38,028,550	44,753	(100,842)	37,972,462
Eastern Wyoming	397	WYP	318,510	(130,702)	74,062,078	298,045	(130,702)	74,229,421	314,910	(130,702)	74,413,629
Utah	397	UT	913,783	(530,751)	217,865,228	902,934	(530,751)	218,237,412	1,010,193	(530,751)	218,716,855
Idaho	397	ID	114,913	(87,666)	43,285,485	108,068	(87,666)	43,305,887	113,753	(87,666)	43,331,973
Western Wyoming	397	WYU	-	(17,563)	13,491,765	-	(17,563)	13,474,202	-	(17,563)	13,456,639
Pre-merger Pacific	397	SG	-	(8,667)	551,746	-	(8,667)	543,080	-	(8,667)	534,413
Pre-merger Utah	397	SG	-	(27,378)	1,944,913	-	(27,378)	1,917,535	-	(27,378)	1,890,156
Post-merger	397	SG	-	(752,692)	109,773,211	-	(752,692)	109,020,518	-	(752,692)	108,267,826
Post-merger	397	SO	7,216,508	(1,273,167)	1,011,931,634	4,917,957	(1,273,167)	1,015,576,425	3,213,025	(1,273,167)	1,017,516,283
Post-merger	397	SG	-	-	-	-	-	-	-	-	-
Post-merger	397	SG	-	(331)	188,913	-	(331)	188,582	-	(331)	188,251
Customer Service	397	CN	-	(77,602)	237,751,860	-	(77,602)	237,674,258	-	(77,602)	237,596,655
Fuel Related	397	SE	-	(13,073)	2,656,404	-	(13,073)	2,643,331	-	(13,073)	2,630,259
Total General Plant			8,838,889	(3,779,796)	1,928,192,442	6,867,147	(3,779,796)	1,931,279,793	5,068,972	(3,779,796)	1,932,568,969
Mining Plant:											
Coal Mine	399	SE	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Mining Plant			-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Intangible Plant:										-	
Pre-merger Utah	303	SG	-	(2,057)	452,917	-	(2,057)	450,860	-	(2,057)	448,804
Pre-merger Pacific	303	SG	-	-	-	-	-	-	-	-	-
California	303	CA	-	(147)	470,576	-	(147)	470,429	-	(147)	470,282
Customer Service	303	CN	-	(154,776)	(1,857,318)	-	(154,776)	(2,012,094)	-	(154,776)	(2,166,871)
Idaho	303	ID	-	(243)	4,353,680	-	(243)	4,353,437	-	(243)	4,353,195
Oregon	303	OR	-	(225)	4,599,014	-	(225)	4,598,788	-	(225)	4,598,563
Fuel Related	303	SE	-	-	-	-	-	-	-	-	-
Post-merger	303	SG	-	(315,712)	198,895,589	-	(315,712)	198,579,877	-	(315,712)	198,264,165
Post-merger	303	OTHER	-	-	-	-	-	-	-	-	-
Hydro Relicensing	303	SG-P	-	-	103,455,075	-	-	103,455,075	-	-	103,455,075
Hydro Relicensing	303	SG-U	-	(14,920)	9,845,172	-	(14,920)	9,830,251	-	(14,920)	9,815,331
General Office	303	SO	-	(677,200)	(8,126,395)	-	(677,200)	(8,803,594)	-	(677,200)	(9,480,794)
Utah	303	UT	-	(404)	7,439,603	-	(404)	7,439,199	-	(404)	7,438,795
Washington	303	WA	-	(252)	2,018,221	-	(252)	2,017,970	-	(252)	2,017,718
Eastern Wyoming	303	WYP	-	(6,676)	5,188,286	-	(6,676)	5,181,609	-	(6,676)	5,174,933
Western Wyoming	303	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant			-	(1,172,612)	326,734,419	-	(1,172,612)	325,561,807	-	(1,172,612)	324,389,195
Total			178,946,386	(18,099,865)	40,442,637,336	120,760,576	(18,099,865)	40,545,298,047	144,273,916	(18,099,865)	40,671,472,097

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Sep 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Oct 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Nov 2026
Steam Production Plant:											
Pre-merger Pacific	312	SG	-	(181,436)	984,870,570	-	(181,436)	984,689,134	-	(181,436)	984,507,698
Pre-merger Utah	312	SG	-	(325,979)	1,009,815,055	-	(325,979)	1,009,489,076	-	(325,979)	1,009,163,096
Post-merger	312	SG	1,179,309	(3,178,251)	5,175,644,095	6,790,767	(3,178,251)	5,179,256,610	5,116,564	(3,178,251)	5,181,194,923
Post-merger	312	SG	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Total Steam Plant			1,179,309	(3,685,667)	7,171,596,572	6,790,767	(3,685,667)	7,174,701,671	5,116,564	(3,685,667)	7,176,132,568
Hydro Production Plant:											
Pre-merger Pacific	332	SG	-	(29,571)	173,315,755	-	(29,571)	173,286,185	-	(29,571)	173,256,614
Pre-merger Utah	332	SG	-	(19,142)	39,279,927	-	(19,142)	39,260,786	-	(19,142)	39,241,644
Post-merger	332	SG	-	-	13,047,000	-	-	13,047,000	-	-	13,047,000
Post-merger	332	SG-P	1,564,323	(213,901)	795,363,251	4,093,979	(213,901)	799,243,329	20,180,455	(213,901)	819,209,883
Post-merger	332	SG-U	(53,441)	(39,907)	182,138,535	9,289,446	(39,907)	191,388,074	1,582,162	(39,907)	192,930,329
Total Hydro Plant			1,510,882	(302,521)	1,203,144,470	13,383,425	(302,521)	1,216,225,374	21,762,617	(302,521)	1,237,685,471
Solar Production Plant:											
Oregon	338XP	OR	-	-	849,123	-	-	849,123	-	-	849,123
Utah	338XP	UT	(123)	-	559,169	(123)	-	559,046	(123)	-	558,923
Post-merger	338XP	SG	-	-	56,322	-	-	56,322	-	-	56,322
Post-merger	338XP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			(123)	-	1,464,615	(123)	-	1,464,492	(123)	-	1,464,368
Wind Production Plant:											
Oregon	338WP	OR	-	-	-	-	-	-	-	-	-
Utah	338WP	UT	-	-	-	-	-	-	-	-	-
Post-merger	338WP	SG	2,589,333	-	3,824,864,875	(107,511)	-	3,824,757,364	1,936,225	-	3,826,693,589
Post-merger	338WP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			2,589,333	-	3,824,864,875	(107,511)	-	3,824,757,364	1,936,225	-	3,826,693,589
Renewable Production Plant:											
Oregon	339RP	OR	-	-	-	-	-	-	-	-	-
Utah	339RP	UT	-	-	-	-	-	-	-	-	-
Post-merger	339RP	SG	14,174	-	158,965,475	14,174	-	158,979,649	14,174	-	158,993,823
Post-merger	339RP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			14,174	-	158,965,475	14,174	-	158,979,649	14,174	-	158,993,823
Other Production Plant:											
Pre-merger Pacific	343	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	343	SG	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	343	SG	(2,984)	(2,338,824)	1,980,669,796	85,126	(2,338,824)	1,978,416,097	7,178,589	(2,338,824)	1,983,255,861
Post-merger	343	SG	-	(29,730)	88,476,641	-	(29,730)	88,446,911	-	(29,730)	88,417,181
Post-merger	343	SG	-	-	-	-	-	-	-	-	-
Total Other Plant			(2,984)	(2,368,554)	2,069,381,566	85,126	(2,368,554)	2,067,098,137	7,178,589	(2,368,554)	2,071,908,171

Transmission Plant:

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California	352	CA	-	-	-	-	-	-	-	-	-
Oregon	352	OR	2,596,848	-	188,633,218	2,603,851	-	191,237,070	2,624,764	-	193,861,834
Washington	352	WA	-	-	-	-	-	-	-	-	-
Wyoing	352	WYP	-	-	-	-	-	-	-	-	-
Wyoming	352	WYU	-	-	-	-	-	-	-	-	-
Utah	352	UT	-	-	-	-	-	-	-	-	-
Idaho	352	ID	-	-	-	-	-	-	-	-	-
System	355	OTHER	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	355	SG	-	(169,652)	469,800,234	-	(169,652)	469,630,582	-	(169,652)	469,460,930
Pre-merger Utah	355	SG	-	(295,257)	600,560,904	-	(295,257)	600,265,647	-	(295,257)	599,970,390
Post-merger	355	SG	44,621,731	(1,336,358)	11,007,853,430	58,666,162	(1,336,358)	11,065,183,234	52,442,770	(1,336,358)	11,116,289,646
Total Transmission Plant			47,218,580	(1,801,267)	12,266,847,787	61,270,013	(1,801,267)	12,326,316,533	55,067,535	(1,801,267)	12,379,582,800
Distribution Plant:											
California	360-373	CA	2,071,625	(291,523)	762,024,989	8,740,841	(291,523)	770,474,307	7,320,346	(291,523)	777,503,130
Oregon	360-373	OR	17,214,023	(1,094,288)	3,510,457,487	14,966,116	(1,094,288)	3,524,329,315	20,128,274	(1,094,288)	3,543,363,300
Washington	360-373	WA	1,716,690	(229,053)	742,290,432	1,559,316	(229,053)	743,620,695	1,259,975	(229,053)	744,651,617
Eastern Wyoming	360-373	WYP	5,652,815	(278,411)	901,660,465	4,657,728	(278,411)	906,039,781	26,854,034	(278,411)	932,615,404
Utah	360-373	UT	25,716,010	(2,591,633)	5,141,063,319	37,587,950	(2,591,633)	5,176,059,636	20,720,615	(2,591,633)	5,194,188,618
Idaho	360-373	ID	3,345,102	(451,084)	539,786,247	2,579,861	(451,084)	541,915,024	2,521,384	(451,084)	543,985,324
Western Wyoming	360-373	WYU	-	(53,455)	165,687,613	-	(53,455)	165,634,158	-	(53,455)	165,580,703
System	360-373	SNPD	-	-	37,730,467	-	-	37,730,467	-	-	37,730,467
System	360-373	CN	-	-	10,802,634	-	-	10,802,634	-	-	10,802,634
System	360-373	SO	-	-	-	-	-	-	-	-	-
System	360-373	SG	-	-	-	-	-	-	-	-	-
System	360-373	OTHER	-	-	-	-	-	-	-	-	-
Total Distribution Plant			55,716,266	(4,989,448)	11,811,503,652	70,091,813	(4,989,448)	11,876,606,017	78,804,628	(4,989,448)	11,950,421,197
Energy Storage Plant											
California	387	CA	-	-	-	-	-	-	-	-	-
Oregon	387	OR	-	-	-	-	-	-	-	-	-
Washington	387	WA	-	-	-	-	-	-	-	-	-
Eastern Wyoming	387	WYP	-	-	-	-	-	-	-	-	-
Utah	387	UT	-	-	-	-	-	-	-	-	-
Idaho	387	ID	-	-	-	-	-	-	-	-	-
Western Wyoming	387	WYU	-	-	-	-	-	-	-	-	-
System	387	CN	-	-	-	-	-	-	-	-	-
System	387	SNPD	-	-	-	-	-	-	-	-	-
System	387	SG	-	-	-	-	-	-	-	-	-
System	387	SO	-	-	-	-	-	-	-	-	-
System	387	OTHER	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-	-

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General Plant:											
California	397	CA	22,533	(50,275)	16,602,215	37,319	(50,275)	16,589,259	35,374	(50,275)	16,574,358
Oregon	397	OR	348,792	(709,086)	159,063,318	599,142	(709,086)	158,953,374	567,714	(709,086)	158,812,003
Washington	397	WA	44,641	(100,842)	37,916,261	74,211	(100,842)	37,889,630	70,322	(100,842)	37,859,110
Eastern Wyoming	397	WYP	304,585	(130,702)	74,587,511	314,800	(130,702)	74,771,608	331,724	(130,702)	74,972,630
Utah	397	UT	921,509	(530,751)	219,107,613	910,873	(530,751)	219,487,735	1,015,896	(530,751)	219,972,881
Idaho	397	ID	110,462	(87,666)	43,354,768	113,812	(87,666)	43,380,914	119,523	(87,666)	43,412,770
Western Wyoming	397	WYU	-	(17,563)	13,439,076	-	(17,563)	13,421,513	-	(17,563)	13,403,950
Pre-merger Pacific	397	SG	-	(8,667)	525,746	-	(8,667)	517,079	-	(8,667)	508,413
Pre-merger Utah	397	SG	-	(27,378)	1,862,778	-	(27,378)	1,835,400	-	(27,378)	1,808,021
Post-merger	397	SG	-	(752,692)	107,515,134	-	(752,692)	106,762,441	-	(752,692)	106,009,749
Post-merger	397	SO	3,588,119	(1,273,167)	1,019,831,235	3,739,047	(1,273,167)	1,022,297,115	4,807,149	(1,273,167)	1,025,831,097
Post-merger	397	SG	-	-	-	-	-	-	-	-	-
Post-merger	397	SG	-	(331)	187,919	-	(331)	187,588	-	(331)	187,257
Customer Service	397	CN	-	(77,602)	237,519,053	-	(77,602)	237,441,451	-	(77,602)	237,363,848
Fuel Related	397	SE	-	(13,073)	2,617,186	-	(13,073)	2,604,113	-	(13,073)	2,591,040
Total General Plant			5,340,641	(3,779,796)	1,934,129,813	5,789,204	(3,779,796)	1,936,139,221	6,947,701	(3,779,796)	1,939,307,127
Mining Plant:											
Coal Mine	399	SE	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Mining Plant			-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Intangible Plant:											
Pre-merger Utah	303	SG	-	(2,057)	446,747	-	(2,057)	444,691	-	(2,057)	442,634
Pre-merger Pacific	303	SG	-	-	-	-	-	-	-	-	-
California	303	CA	-	(147)	470,134	-	(147)	469,987	-	(147)	469,840
Customer Service	303	CN	-	(154,776)	(2,321,647)	-	(154,776)	(2,476,423)	-	(154,776)	(2,631,200)
Idaho	303	ID	-	(243)	4,352,952	-	(243)	4,352,710	-	(243)	4,352,467
Oregon	303	OR	-	(225)	4,598,337	-	(225)	4,598,112	-	(225)	4,597,887
Fuel Related	303	SE	-	-	-	-	-	-	-	-	-
Post-merger	303	SG	-	(315,712)	197,948,453	-	(315,712)	197,632,742	-	(315,712)	197,317,030
Post-merger	303	OTHER	-	-	-	-	-	-	-	-	-
Hydro Relicensing	303	SG-P	-	-	103,455,075	-	-	103,455,075	-	-	103,455,075
Hydro Relicensing	303	SG-U	-	(14,920)	9,800,410	-	(14,920)	9,785,490	-	(14,920)	9,770,570
General Office	303	SO	-	(677,200)	(10,157,993)	-	(677,200)	(10,835,193)	-	(677,200)	(11,512,392)
Utah	303	UT	-	(404)	7,438,391	-	(404)	7,437,988	-	(404)	7,437,584
Washington	303	WA	-	(252)	2,017,466	-	(252)	2,017,214	-	(252)	2,016,962
Eastern Wyoming	303	WYP	-	(6,676)	5,168,257	-	(6,676)	5,161,581	-	(6,676)	5,154,904
Western Wyoming	303	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant			-	(1,172,612)	323,216,583	-	(1,172,612)	322,043,972	-	(1,172,612)	320,871,360
Total			113,566,077	(18,099,865)	40,766,938,309	157,316,887	(18,099,865)	40,906,155,331	176,827,910	(18,099,865)	41,064,883,376

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Dec 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jan 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Feb 2027
Steam Production Plant:											
Pre-merger Pacific	312	SG	-	(181,436)	984,326,261	-	(181,436)	984,144,825	-	(181,436)	983,963,389
Pre-merger Utah	312	SG	-	(325,979)	1,008,837,117	-	(325,979)	1,008,511,137	-	(325,979)	1,008,185,158
Post-merger	312	SG	39,999,797	(3,178,251)	5,218,016,468	374,123	(3,178,251)	5,215,212,340	1,449,114	(3,178,251)	5,213,483,202
Post-merger	312	SG	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Total Steam Plant			39,999,797	(3,685,667)	7,212,446,698	374,123	(3,685,667)	7,209,135,153	1,449,114	(3,685,667)	7,206,898,600
Hydro Production Plant:											
Pre-merger Pacific	332	SG	-	(29,571)	173,227,044	-	(29,571)	173,197,473	-	(29,571)	173,167,903
Pre-merger Utah	332	SG	-	(19,142)	39,222,503	-	(19,142)	39,203,361	-	(19,142)	39,184,219
Post-merger	332	SG	-	-	13,047,000	-	-	13,047,000	-	-	13,047,000
Post-merger	332	SG-P	75,308,356	(213,901)	894,304,337	32,050	(213,901)	894,122,486	32,050	(213,901)	893,940,634
Post-merger	332	SG-U	12,771,336	(39,907)	205,661,758	(53,286)	(39,907)	205,568,565	(53,286)	(39,907)	205,475,372
Total Hydro Plant			88,079,692	(302,521)	1,325,462,642	(21,236)	(302,521)	1,325,138,886	(21,236)	(302,521)	1,324,815,129
Solar Production Plant:											
Oregon	338XP	OR	70,080	-	919,203	-	-	919,203	-	-	919,203
Utah	338XP	UT	(123)	-	558,800	(123)	-	558,677	(123)	-	558,554
Post-merger	338XP	SG	-	-	56,322	-	-	56,322	-	-	56,322
Post-merger	338XP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			69,957	-	1,534,325	(123)	-	1,534,202	(123)	-	1,534,079
Wind Production Plant:											
Oregon	338WP	OR	-	-	-	-	-	-	-	-	-
Utah	338WP	UT	-	-	-	-	-	-	-	-	-
Post-merger	338WP	SG	17,589,829	-	3,844,283,418	(107,511)	-	3,844,175,906	(107,511)	-	3,844,068,395
Post-merger	338WP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			17,589,829	-	3,844,283,418	(107,511)	-	3,844,175,906	(107,511)	-	3,844,068,395
Renewable Production Plant:											
Oregon	339RP	OR	-	-	-	-	-	-	-	-	-
Utah	339RP	UT	-	-	-	-	-	-	-	-	-
Post-merger	339RP	SG	14,174	-	159,007,998	14,564	-	159,022,562	14,564	-	159,037,126
Post-merger	339RP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			14,174	-	159,007,998	14,564	-	159,022,562	14,564	-	159,037,126
Other Production Plant:											
Pre-merger Pacific	343	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	343	SG	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	343	SG	55,349,139	(2,338,824)	2,036,266,176	(496)	(2,338,824)	2,033,926,855	(496)	(2,338,824)	2,031,587,535
Post-merger	343	SG	-	(29,730)	88,387,451	-	(29,730)	88,357,721	-	(29,730)	88,327,991
Post-merger	343	SG	-	-	-	-	-	-	-	-	-
Total Other Plant			55,349,139	(2,368,554)	2,124,888,756	(496)	(2,368,554)	2,122,519,706	(496)	(2,368,554)	2,120,150,655

Transmission Plant:

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Dec 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jan 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Feb 2027
California	352	CA	-	-	-	-	-	-	-	-	-
Oregon	352	OR	2,616,860	-	196,478,694	101,657	-	196,580,350	118,417	-	196,698,768
Washington	352	WA	-	-	-	-	-	-	-	-	-
Wyoing	352	WYP	-	-	-	-	-	-	-	-	-
Wyoming	352	WYU	-	-	-	-	-	-	-	-	-
Utah	352	UT	-	-	-	-	-	-	-	-	-
Idaho	352	ID	-	-	-	-	-	-	-	-	-
System	355	OTHER	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	355	SG	-	(169,652)	469,291,278	-	(169,652)	469,121,626	-	(169,652)	468,951,974
Pre-merger Utah	355	SG	-	(295,257)	599,675,133	-	(295,257)	599,379,876	-	(295,257)	599,084,619
Post-merger	355	SG	94,206,972	(1,336,358)	11,209,160,260	6,582,513	(1,336,358)	11,214,406,415	74,477,954	(1,336,358)	11,287,548,012
Total Transmission Plant			96,823,832	(1,801,267)	12,474,605,365	6,684,170	(1,801,267)	12,479,488,268	74,596,371	(1,801,267)	12,552,283,373
Distribution Plant:											
California	360-373	CA	32,013,793	(291,523)	809,225,399	3,454,072	(291,523)	812,387,948	4,876,510	(291,523)	816,972,934
Oregon	360-373	OR	9,411,824	(1,094,288)	3,551,680,837	4,189,634	(1,094,288)	3,554,776,183	3,775,891	(1,094,288)	3,557,457,786
Washington	360-373	WA	1,765,704	(229,053)	746,188,268	1,020,079	(229,053)	746,979,294	957,033	(229,053)	747,707,274
Eastern Wyoming	360-373	WYP	6,441,023	(278,411)	938,778,015	2,455,664	(278,411)	940,955,268	2,650,915	(278,411)	943,327,772
Utah	360-373	UT	72,612,717	(2,591,633)	5,264,209,702	14,180,851	(2,591,633)	5,275,798,920	15,451,887	(2,591,633)	5,288,659,173
Idaho	360-373	ID	7,496,548	(451,084)	551,030,788	2,030,091	(451,084)	552,609,795	2,268,319	(451,084)	554,427,030
Western Wyoming	360-373	WYU	-	(53,455)	165,527,248	-	(53,455)	165,473,793	-	(53,455)	165,420,338
System	360-373	SNPD	-	-	37,730,467	-	-	37,730,467	-	-	37,730,467
System	360-373	CN	-	-	10,802,634	-	-	10,802,634	-	-	10,802,634
System	360-373	SO	-	-	-	-	-	-	-	-	-
System	360-373	SG	-	-	-	-	-	-	-	-	-
System	360-373	OTHER	-	-	-	-	-	-	-	-	-
Total Distribution Plant			129,741,610	(4,989,448)	12,075,173,358	27,330,391	(4,989,448)	12,097,514,301	29,980,556	(4,989,448)	12,122,505,408
Energy Storage Plant											
California	387	CA	-	-	-	-	-	-	-	-	-
Oregon	387	OR	-	-	-	-	-	-	-	-	-
Washington	387	WA	-	-	-	-	-	-	-	-	-
Eastern Wyoming	387	WYP	-	-	-	-	-	-	-	-	-
Utah	387	UT	-	-	-	-	-	-	-	-	-
Idaho	387	ID	-	-	-	-	-	-	-	-	-
Western Wyoming	387	WYU	-	-	-	-	-	-	-	-	-
System	387	CN	-	-	-	-	-	-	-	-	-
System	387	SNPD	-	-	-	-	-	-	-	-	-
System	387	SG	-	-	-	-	-	-	-	-	-
System	387	SO	-	-	-	-	-	-	-	-	-
System	387	OTHER	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-	-

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Dec 2026	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jan 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Feb 2027
General Plant:											
California	397	CA	44,631	(50,275)	16,568,714	9,020	(50,275)	16,527,459	9,167	(50,275)	16,486,351
Oregon	397	OR	722,721	(709,086)	158,825,638	128,307	(709,086)	158,244,859	131,177	(709,086)	157,666,950
Washington	397	WA	88,837	(100,842)	37,847,106	17,664	(100,842)	37,763,928	17,956	(100,842)	37,681,042
Eastern Wyoming	397	WYP	1,265,631	(130,702)	76,107,559	248,800	(130,702)	76,225,656	221,473	(130,702)	76,316,427
Utah	397	UT	909,258	(530,751)	220,351,388	605,312	(530,751)	220,425,950	542,205	(530,751)	220,437,404
Idaho	397	ID	126,458	(87,666)	43,451,562	113,936	(87,666)	43,477,832	104,761	(87,666)	43,494,926
Western Wyoming	397	WYU	-	(17,563)	13,386,387	-	(17,563)	13,368,824	-	(17,563)	13,351,262
Pre-merger Pacific	397	SG	-	(8,667)	499,746	-	(8,667)	491,079	-	(8,667)	482,412
Pre-merger Utah	397	SG	-	(27,378)	1,780,643	-	(27,378)	1,753,264	-	(27,378)	1,725,886
Post-merger	397	SG	-	(752,692)	105,257,056	-	(752,692)	104,504,364	-	(752,692)	103,751,672
Post-merger	397	SO	41,078,733	(1,273,167)	1,065,636,663	1,876,601	(1,273,167)	1,066,240,097	2,303,121	(1,273,167)	1,067,270,050
Post-merger	397	SG	-	-	-	-	-	-	-	-	-
Post-merger	397	SG	-	(331)	186,926	-	(331)	186,594	-	(331)	186,263
Customer Service	397	CN	-	(77,602)	237,286,246	-	(77,602)	237,208,643	-	(77,602)	237,131,041
Fuel Related	397	SE	-	(13,073)	2,577,968	-	(13,073)	2,564,895	-	(13,073)	2,551,822
Total General Plant			44,236,270	(3,779,796)	1,979,763,601	2,999,640	(3,779,796)	1,978,983,445	3,329,859	(3,779,796)	1,978,533,508
Mining Plant:											
Coal Mine	399	SE	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Mining Plant			-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Intangible Plant:											
Pre-merger Utah	303	SG	-	(2,057)	440,577	-	(2,057)	438,521	-	(2,057)	436,464
Pre-merger Pacific	303	SG	-	-	-	-	-	-	-	-	-
California	303	CA	-	(147)	469,693	-	(147)	469,546	-	(147)	469,399
Customer Service	303	CN	-	(154,776)	(2,785,976)	-	(154,776)	(2,940,753)	-	(154,776)	(3,095,529)
Idaho	303	ID	-	(243)	4,352,225	-	(243)	4,351,982	-	(243)	4,351,739
Oregon	303	OR	-	(225)	4,597,661	-	(225)	4,597,436	-	(225)	4,597,210
Fuel Related	303	SE	-	-	-	-	-	-	-	-	-
Post-merger	303	SG	-	(315,712)	197,001,318	-	(315,712)	196,685,607	-	(315,712)	196,369,895
Post-merger	303	OTHER	-	-	-	-	-	-	-	-	-
Hydro Relicensing	303	SG-P	-	-	103,455,075	-	-	103,455,075	-	-	103,455,075
Hydro Relicensing	303	SG-U	-	(14,920)	9,755,649	-	(14,920)	9,740,729	-	(14,920)	9,725,808
General Office	303	SO	-	(677,200)	(12,189,592)	-	(677,200)	(12,866,792)	-	(677,200)	(13,543,991)
Utah	303	UT	-	(404)	7,437,180	-	(404)	7,436,776	-	(404)	7,436,372
Washington	303	WA	-	(252)	2,016,710	-	(252)	2,016,458	-	(252)	2,016,206
Eastern Wyoming	303	WYP	-	(6,676)	5,148,228	-	(6,676)	5,141,552	-	(6,676)	5,134,875
Western Wyoming	303	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant			-	(1,172,612)	319,698,748	-	(1,172,612)	318,526,136	-	(1,172,612)	317,353,524
Total			471,904,299	(18,099,865)	41,518,687,809	37,273,522	(18,099,865)	41,537,861,466	109,241,098	(18,099,865)	41,629,002,698

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Mar 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Apr 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance May 2027
Steam Production Plant:											
Pre-merger Pacific	312	SG	-	(181,436)	983,781,953	-	-	983,781,953	-	-	983,781,953
Pre-merger Utah	312	SG	-	(325,979)	1,007,859,178	-	-	1,007,859,178	-	-	1,007,859,178
Post-merger	312	SG	313,293	(3,178,251)	5,210,618,243	-	-	5,210,618,243	-	-	5,210,618,243
Post-merger	312	SG	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Total Steam Plant			313,293	(3,685,667)	7,203,526,226	-	-	7,203,526,226	-	-	7,203,526,226
Hydro Production Plant:											
Pre-merger Pacific	332	SG	-	(29,571)	173,138,332	-	-	173,138,332	-	-	173,138,332
Pre-merger Utah	332	SG	-	(19,142)	39,165,078	-	-	39,165,078	-	-	39,165,078
Post-merger	332	SG	-	-	13,047,000	-	-	13,047,000	-	-	13,047,000
Post-merger	332	SG-P	32,050	(213,901)	893,758,783	-	-	893,758,783	-	-	893,758,783
Post-merger	332	SG-U	422,596	(39,907)	205,858,061	-	-	205,858,061	-	-	205,858,061
Total Hydro Plant			454,646	(302,521)	1,324,967,254	-	-	1,324,967,254	-	-	1,324,967,254
Solar Production Plant:											
Oregon	338XP	OR	-	-	919,203	-	-	919,203	-	-	919,203
Utah	338XP	UT	(123)	-	558,430	-	-	558,430	-	-	558,430
Post-merger	338XP	SG	-	-	56,322	-	-	56,322	-	-	56,322
Post-merger	338XP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			(123)	-	1,533,956	-	-	1,533,956	-	-	1,533,956
Wind Production Plant:											
Oregon	338WP	OR	-	-	-	-	-	-	-	-	-
Utah	338WP	UT	-	-	-	-	-	-	-	-	-
Post-merger	338WP	SG	3,049,675	-	3,847,118,070	-	-	3,847,118,070	-	-	3,847,118,070
Post-merger	338WP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			3,049,675	-	3,847,118,070	-	-	3,847,118,070	-	-	3,847,118,070
Renewable Production Plant:											
Oregon	339RP	OR	-	-	-	-	-	-	-	-	-
Utah	339RP	UT	-	-	-	-	-	-	-	-	-
Post-merger	339RP	SG	565,349	-	159,602,475	-	-	159,602,475	-	-	159,602,475
Post-merger	339RP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			565,349	-	159,602,475	-	-	159,602,475	-	-	159,602,475
Other Production Plant:											
Pre-merger Pacific	343	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	343	SG	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	343	SG	(496)	(2,338,824)	2,029,248,215	-	-	2,029,248,215	-	-	2,029,248,215
Post-merger	343	SG	-	(29,730)	88,298,261	-	-	88,298,261	-	-	88,298,261
Post-merger	343	SG	-	-	-	-	-	-	-	-	-
Total Other Plant			(496)	(2,368,554)	2,117,781,605	-	-	2,117,781,605	-	-	2,117,781,605

Transmission Plant:

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Mar 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Apr 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance May 2027
California	352	CA	-	-	-	-	-	-	-	-	-
Oregon	352	OR	118,417	-	196,817,185	-	-	196,817,185	-	-	196,817,185
Washington	352	WA	-	-	-	-	-	-	-	-	-
Wyoing	352	WYP	-	-	-	-	-	-	-	-	-
Wyoming	352	WYU	-	-	-	-	-	-	-	-	-
Utah	352	UT	-	-	-	-	-	-	-	-	-
Idaho	352	ID	-	-	-	-	-	-	-	-	-
System	355	OTHER	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	355	SG	-	(169,652)	468,782,323	-	-	468,782,323	-	-	468,782,323
Pre-merger Utah	355	SG	-	(295,257)	598,789,362	-	-	598,789,362	-	-	598,789,362
Post-merger	355	SG	23,569,742	(1,336,358)	11,309,781,396	-	-	11,309,781,396	-	-	11,309,781,396
Total Transmission Plant			23,688,159	(1,801,267)	12,574,170,265	-	-	12,574,170,265	-	-	12,574,170,265
Distribution Plant:											
California	360-373	CA	15,075,351	(291,523)	831,756,762	-	-	831,756,762	-	-	831,756,762
Oregon	360-373	OR	8,658,105	(1,094,288)	3,565,021,602	-	-	3,565,021,602	-	-	3,565,021,602
Washington	360-373	WA	2,134,424	(229,053)	749,612,645	-	-	749,612,645	-	-	749,612,645
Eastern Wyoming	360-373	WYP	3,140,588	(278,411)	946,189,949	-	-	946,189,949	-	-	946,189,949
Utah	360-373	UT	16,800,635	(2,591,633)	5,302,868,174	-	-	5,302,868,174	-	-	5,302,868,174
Idaho	360-373	ID	2,810,726	(451,084)	556,786,672	-	-	556,786,672	-	-	556,786,672
Western Wyoming	360-373	WYU	-	(53,455)	165,366,883	-	-	165,366,883	-	-	165,366,883
System	360-373	SNPD	-	-	37,730,467	-	-	37,730,467	-	-	37,730,467
System	360-373	CN	-	-	10,802,634	-	-	10,802,634	-	-	10,802,634
System	360-373	SO	-	-	-	-	-	-	-	-	-
System	360-373	SG	-	-	-	-	-	-	-	-	-
System	360-373	OTHER	-	-	-	-	-	-	-	-	-
Total Distribution Plant			48,619,830	(4,989,448)	12,166,135,790	-	-	12,166,135,790	-	-	12,166,135,790
Energy Storage Plant											
California	387	CA	-	-	-	-	-	-	-	-	-
Oregon	387	OR	-	-	-	-	-	-	-	-	-
Washington	387	WA	-	-	-	-	-	-	-	-	-
Eastern Wyoming	387	WYP	-	-	-	-	-	-	-	-	-
Utah	387	UT	-	-	-	-	-	-	-	-	-
Idaho	387	ID	-	-	-	-	-	-	-	-	-
Western Wyoming	387	WYU	-	-	-	-	-	-	-	-	-
System	387	CN	-	-	-	-	-	-	-	-	-
System	387	SNPD	-	-	-	-	-	-	-	-	-
System	387	SG	-	-	-	-	-	-	-	-	-
System	387	SO	-	-	-	-	-	-	-	-	-
System	387	OTHER	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-	-

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Mar 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Apr 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance May 2027
General Plant:											
California	397	CA	10,960	(50,275)	16,447,036	-	-	16,447,036	-	-	16,447,036
Oregon	397	OR	161,612	(709,086)	157,119,476	-	-	157,119,476	-	-	157,119,476
Washington	397	WA	21,543	(100,842)	37,601,744	-	-	37,601,744	-	-	37,601,744
Eastern Wyoming	397	WYP	227,566	(130,702)	76,413,290	-	-	76,413,290	-	-	76,413,290
Utah	397	UT	558,319	(530,751)	220,464,973	-	-	220,464,973	-	-	220,464,973
Idaho	397	ID	107,179	(87,666)	43,514,439	-	-	43,514,439	-	-	43,514,439
Western Wyoming	397	WYU	-	(17,563)	13,333,699	-	-	13,333,699	-	-	13,333,699
Pre-merger Pacific	397	SG	-	(8,667)	473,746	-	-	473,746	-	-	473,746
Pre-merger Utah	397	SG	-	(27,378)	1,698,508	-	-	1,698,508	-	-	1,698,508
Post-merger	397	SG	-	(752,692)	102,998,979	-	-	102,998,979	-	-	102,998,979
Post-merger	397	SO	4,587,043	(1,273,167)	1,070,583,927	-	-	1,070,583,927	-	-	1,070,583,927
Post-merger	397	SG	-	-	-	-	-	-	-	-	-
Post-merger	397	SG	-	(331)	185,932	-	-	185,932	-	-	185,932
Customer Service	397	CN	-	(77,602)	237,053,439	-	-	237,053,439	-	-	237,053,439
Fuel Related	397	SE	-	(13,073)	2,538,749	-	-	2,538,749	-	-	2,538,749
Total General Plant			5,674,222	(3,779,796)	1,980,427,935	-	-	1,980,427,935	-	-	1,980,427,935
Mining Plant:											
Coal Mine	399	SE	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Mining Plant			-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Intangible Plant:											
Pre-merger Utah	303	SG	-	(2,057)	434,408	-	-	434,408	-	-	434,408
Pre-merger Pacific	303	SG	-	-	-	-	-	-	-	-	-
California	303	CA	-	(147)	469,252	-	-	469,252	-	-	469,252
Customer Service	303	CN	-	(154,776)	(3,250,306)	-	-	(3,250,306)	-	-	(3,250,306)
Idaho	303	ID	-	(243)	4,351,497	-	-	4,351,497	-	-	4,351,497
Oregon	303	OR	-	(225)	4,596,985	-	-	4,596,985	-	-	4,596,985
Fuel Related	303	SE	-	-	-	-	-	-	-	-	-
Post-merger	303	SG	-	(315,712)	196,054,183	-	-	196,054,183	-	-	196,054,183
Post-merger	303	OTHER	-	-	-	-	-	-	-	-	-
Hydro Relicensing	303	SG-P	-	-	103,455,075	-	-	103,455,075	-	-	103,455,075
Hydro Relicensing	303	SG-U	-	(14,920)	9,710,888	-	-	9,710,888	-	-	9,710,888
General Office	303	SO	-	(677,200)	(14,221,191)	-	-	(14,221,191)	-	-	(14,221,191)
Utah	303	UT	-	(404)	7,435,969	-	-	7,435,969	-	-	7,435,969
Washington	303	WA	-	(252)	2,015,954	-	-	2,015,954	-	-	2,015,954
Eastern Wyoming	303	WYP	-	(6,676)	5,128,199	-	-	5,128,199	-	-	5,128,199
Western Wyoming	303	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant			-	(1,172,612)	316,180,912	-	-	316,180,912	-	-	316,180,912
Total			82,364,555	(18,099,865)	41,693,267,388	-	-	41,693,267,388	-	-	41,693,267,388

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jun 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jul 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Aug 2027
Steam Production Plant:											
Pre-merger Pacific	312	SG	-	-	983,781,953	-	-	983,781,953	-	-	983,781,953
Pre-merger Utah	312	SG	-	-	1,007,859,178	-	-	1,007,859,178	-	-	1,007,859,178
Post-merger	312	SG	-	-	5,210,618,243	-	-	5,210,618,243	-	-	5,210,618,243
Post-merger	312	SG	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Total Steam Plant			-	-	7,203,526,226	-	-	7,203,526,226	-	-	7,203,526,226
Hydro Production Plant:											
Pre-merger Pacific	332	SG	-	-	173,138,332	-	-	173,138,332	-	-	173,138,332
Pre-merger Utah	332	SG	-	-	39,165,078	-	-	39,165,078	-	-	39,165,078
Post-merger	332	SG	-	-	13,047,000	-	-	13,047,000	-	-	13,047,000
Post-merger	332	SG-P	-	-	893,758,783	-	-	893,758,783	-	-	893,758,783
Post-merger	332	SG-U	-	-	205,858,061	-	-	205,858,061	-	-	205,858,061
Total Hydro Plant			-	-	1,324,967,254	-	-	1,324,967,254	-	-	1,324,967,254
Solar Production Plant:											
Oregon	338XP	OR	-	-	919,203	-	-	919,203	-	-	919,203
Utah	338XP	UT	-	-	558,430	-	-	558,430	-	-	558,430
Post-merger	338XP	SG	-	-	56,322	-	-	56,322	-	-	56,322
Post-merger	338XP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	1,533,956	-	-	1,533,956	-	-	1,533,956
Wind Production Plant:											
Oregon	338WP	OR	-	-	-	-	-	-	-	-	-
Utah	338WP	UT	-	-	-	-	-	-	-	-	-
Post-merger	338WP	SG	-	-	3,847,118,070	-	-	3,847,118,070	-	-	3,847,118,070
Post-merger	338WP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	3,847,118,070	-	-	3,847,118,070	-	-	3,847,118,070
Renewable Production Plant:											
Oregon	339RP	OR	-	-	-	-	-	-	-	-	-
Utah	339RP	UT	-	-	-	-	-	-	-	-	-
Post-merger	339RP	SG	-	-	159,602,475	-	-	159,602,475	-	-	159,602,475
Post-merger	339RP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	159,602,475	-	-	159,602,475	-	-	159,602,475
Other Production Plant:											
Pre-merger Pacific	343	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	343	SG	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	343	SG	-	-	2,029,248,215	-	-	2,029,248,215	-	-	2,029,248,215
Post-merger	343	SG	-	-	88,298,261	-	-	88,298,261	-	-	88,298,261
Post-merger	343	SG	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	2,117,781,605	-	-	2,117,781,605	-	-	2,117,781,605

Transmission Plant:

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jun 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jul 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Aug 2027
California	352	CA	-	-	-	-	-	-	-	-	-
Oregon	352	OR	-	-	196,817,185	-	-	196,817,185	-	-	196,817,185
Washington	352	WA	-	-	-	-	-	-	-	-	-
Wyoing	352	WYP	-	-	-	-	-	-	-	-	-
Wyoming	352	WYU	-	-	-	-	-	-	-	-	-
Utah	352	UT	-	-	-	-	-	-	-	-	-
Idaho	352	ID	-	-	-	-	-	-	-	-	-
System	355	OTHER	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	355	SG	-	-	468,782,323	-	-	468,782,323	-	-	468,782,323
Pre-merger Utah	355	SG	-	-	598,789,362	-	-	598,789,362	-	-	598,789,362
Post-merger	355	SG	-	-	11,309,781,396	-	-	11,309,781,396	-	-	11,309,781,396
Total Transmission Plant			-	-	12,574,170,265	-	-	12,574,170,265	-	-	12,574,170,265
Distribution Plant:											
California	360-373	CA	-	-	831,756,762	-	-	831,756,762	-	-	831,756,762
Oregon	360-373	OR	-	-	3,565,021,602	-	-	3,565,021,602	-	-	3,565,021,602
Washington	360-373	WA	-	-	749,612,645	-	-	749,612,645	-	-	749,612,645
Eastern Wyoming	360-373	WYP	-	-	946,189,949	-	-	946,189,949	-	-	946,189,949
Utah	360-373	UT	-	-	5,302,868,174	-	-	5,302,868,174	-	-	5,302,868,174
Idaho	360-373	ID	-	-	556,786,672	-	-	556,786,672	-	-	556,786,672
Western Wyoming	360-373	WYU	-	-	165,366,883	-	-	165,366,883	-	-	165,366,883
System	360-373	SNPD	-	-	37,730,467	-	-	37,730,467	-	-	37,730,467
System	360-373	CN	-	-	10,802,634	-	-	10,802,634	-	-	10,802,634
System	360-373	SO	-	-	-	-	-	-	-	-	-
System	360-373	SG	-	-	-	-	-	-	-	-	-
System	360-373	OTHER	-	-	-	-	-	-	-	-	-
Total Distribution Plant			-	-	12,166,135,790	-	-	12,166,135,790	-	-	12,166,135,790
Energy Storage Plant											
California	387	CA	-	-	-	-	-	-	-	-	-
Oregon	387	OR	-	-	-	-	-	-	-	-	-
Washington	387	WA	-	-	-	-	-	-	-	-	-
Eastern Wyoming	387	WYP	-	-	-	-	-	-	-	-	-
Utah	387	UT	-	-	-	-	-	-	-	-	-
Idaho	387	ID	-	-	-	-	-	-	-	-	-
Western Wyoming	387	WYU	-	-	-	-	-	-	-	-	-
System	387	CN	-	-	-	-	-	-	-	-	-
System	387	SNPD	-	-	-	-	-	-	-	-	-
System	387	SG	-	-	-	-	-	-	-	-	-
System	387	SO	-	-	-	-	-	-	-	-	-
System	387	OTHER	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-	-

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jun 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Jul 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Aug 2027
General Plant:											
California	397	CA	-	-	16,447,036	-	-	16,447,036	-	-	16,447,036
Oregon	397	OR	-	-	157,119,476	-	-	157,119,476	-	-	157,119,476
Washington	397	WA	-	-	37,601,744	-	-	37,601,744	-	-	37,601,744
Eastern Wyoming	397	WYP	-	-	76,413,290	-	-	76,413,290	-	-	76,413,290
Utah	397	UT	-	-	220,464,973	-	-	220,464,973	-	-	220,464,973
Idaho	397	ID	-	-	43,514,439	-	-	43,514,439	-	-	43,514,439
Western Wyoming	397	WYU	-	-	13,333,699	-	-	13,333,699	-	-	13,333,699
Pre-merger Pacific	397	SG	-	-	473,746	-	-	473,746	-	-	473,746
Pre-merger Utah	397	SG	-	-	1,698,508	-	-	1,698,508	-	-	1,698,508
Post-merger	397	SG	-	-	102,998,979	-	-	102,998,979	-	-	102,998,979
Post-merger	397	SO	-	-	1,070,583,927	-	-	1,070,583,927	-	-	1,070,583,927
Post-merger	397	SG	-	-	-	-	-	-	-	-	-
Post-merger	397	SG	-	-	185,932	-	-	185,932	-	-	185,932
Customer Service	397	CN	-	-	237,053,439	-	-	237,053,439	-	-	237,053,439
Fuel Related	397	SE	-	-	2,538,749	-	-	2,538,749	-	-	2,538,749
Total General Plant			-	-	1,980,427,935	-	-	1,980,427,935	-	-	1,980,427,935
Mining Plant:											
Coal Mine	399	SE	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Mining Plant			-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Intangible Plant:											
Pre-merger Utah	303	SG	-	-	434,408	-	-	434,408	-	-	434,408
Pre-merger Pacific	303	SG	-	-	-	-	-	-	-	-	-
California	303	CA	-	-	469,252	-	-	469,252	-	-	469,252
Customer Service	303	CN	-	-	(3,250,306)	-	-	(3,250,306)	-	-	(3,250,306)
Idaho	303	ID	-	-	4,351,497	-	-	4,351,497	-	-	4,351,497
Oregon	303	OR	-	-	4,596,985	-	-	4,596,985	-	-	4,596,985
Fuel Related	303	SE	-	-	-	-	-	-	-	-	-
Post-merger	303	SG	-	-	196,054,183	-	-	196,054,183	-	-	196,054,183
Post-merger	303	OTHER	-	-	-	-	-	-	-	-	-
Hydro Relicensing	303	SG-P	-	-	103,455,075	-	-	103,455,075	-	-	103,455,075
Hydro Relicensing	303	SG-U	-	-	9,710,888	-	-	9,710,888	-	-	9,710,888
General Office	303	SO	-	-	(14,221,191)	-	-	(14,221,191)	-	-	(14,221,191)
Utah	303	UT	-	-	7,435,969	-	-	7,435,969	-	-	7,435,969
Washington	303	WA	-	-	2,015,954	-	-	2,015,954	-	-	2,015,954
Eastern Wyoming	303	WYP	-	-	5,128,199	-	-	5,128,199	-	-	5,128,199
Western Wyoming	303	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant			-	-	316,180,912	-	-	316,180,912	-	-	316,180,912
Total			-	-	41,693,267,388	-	-	41,693,267,388	-	-	41,693,267,388

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Sep 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Oct 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Nov 2027
Steam Production Plant:											
Pre-merger Pacific	312	SG	-	-	983,781,953	-	-	983,781,953	-	-	983,781,953
Pre-merger Utah	312	SG	-	-	1,007,859,178	-	-	1,007,859,178	-	-	1,007,859,178
Post-merger	312	SG	-	-	5,210,618,243	-	-	5,210,618,243	-	-	5,210,618,243
Post-merger	312	SG	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-Merger	312	SG	-	-	-	-	-	-	-	-	-
Post-merger	312	SG	-	-	-	-	-	-	-	-	-
Total Steam Plant			-	-	7,203,526,226	-	-	7,203,526,226	-	-	7,203,526,226
Hydro Production Plant:											
Pre-merger Pacific	332	SG	-	-	173,138,332	-	-	173,138,332	-	-	173,138,332
Pre-merger Utah	332	SG	-	-	39,165,078	-	-	39,165,078	-	-	39,165,078
Post-merger	332	SG	-	-	13,047,000	-	-	13,047,000	-	-	13,047,000
Post-merger	332	SG-P	-	-	893,758,783	-	-	893,758,783	-	-	893,758,783
Post-merger	332	SG-U	-	-	205,858,061	-	-	205,858,061	-	-	205,858,061
Total Hydro Plant			-	-	1,324,967,254	-	-	1,324,967,254	-	-	1,324,967,254
Solar Production Plant:											
Oregon	338XP	OR	-	-	919,203	-	-	919,203	-	-	919,203
Utah	338XP	UT	-	-	558,430	-	-	558,430	-	-	558,430
Post-merger	338XP	SG	-	-	56,322	-	-	56,322	-	-	56,322
Post-merger	338XP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	1,533,956	-	-	1,533,956	-	-	1,533,956
Wind Production Plant:											
Oregon	338WP	OR	-	-	-	-	-	-	-	-	-
Utah	338WP	UT	-	-	-	-	-	-	-	-	-
Post-merger	338WP	SG	-	-	3,847,118,070	-	-	3,847,118,070	-	-	3,847,118,070
Post-merger	338WP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	3,847,118,070	-	-	3,847,118,070	-	-	3,847,118,070
Renewable Production Plant:											
Oregon	339RP	OR	-	-	-	-	-	-	-	-	-
Utah	339RP	UT	-	-	-	-	-	-	-	-	-
Post-merger	339RP	SG	-	-	159,602,475	-	-	159,602,475	-	-	159,602,475
Post-merger	339RP	OTHER	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	159,602,475	-	-	159,602,475	-	-	159,602,475
Other Production Plant:											
Pre-merger Pacific	343	SG	-	-	-	-	-	-	-	-	-
Pre-merger Utah	343	SG	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	343	SG	-	-	2,029,248,215	-	-	2,029,248,215	-	-	2,029,248,215
Post-merger	343	SG	-	-	88,298,261	-	-	88,298,261	-	-	88,298,261
Post-merger	343	SG	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	2,117,781,605	-	-	2,117,781,605	-	-	2,117,781,605

Transmission Plant:

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Sep 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Oct 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Nov 2027
California	352	CA	-	-	-	-	-	-	-	-	-
Oregon	352	OR	-	-	196,817,185	-	-	196,817,185	-	-	196,817,185
Washington	352	WA	-	-	-	-	-	-	-	-	-
Wyoing	352	WYP	-	-	-	-	-	-	-	-	-
Wyoming	352	WYU	-	-	-	-	-	-	-	-	-
Utah	352	UT	-	-	-	-	-	-	-	-	-
Idaho	352	ID	-	-	-	-	-	-	-	-	-
System	355	OTHER	-	-	-	-	-	-	-	-	-
Pre-merger Pacific	355	SG	-	-	468,782,323	-	-	468,782,323	-	-	468,782,323
Pre-merger Utah	355	SG	-	-	598,789,362	-	-	598,789,362	-	-	598,789,362
Post-merger	355	SG	-	-	11,309,781,396	-	-	11,309,781,396	-	-	11,309,781,396
Total Transmission Plant			-	-	12,574,170,265	-	-	12,574,170,265	-	-	12,574,170,265
Distribution Plant:											
California	360-373	CA	-	-	831,756,762	-	-	831,756,762	-	-	831,756,762
Oregon	360-373	OR	-	-	3,565,021,602	-	-	3,565,021,602	-	-	3,565,021,602
Washington	360-373	WA	-	-	749,612,645	-	-	749,612,645	-	-	749,612,645
Eastern Wyoming	360-373	WYP	-	-	946,189,949	-	-	946,189,949	-	-	946,189,949
Utah	360-373	UT	-	-	5,302,868,174	-	-	5,302,868,174	-	-	5,302,868,174
Idaho	360-373	ID	-	-	556,786,672	-	-	556,786,672	-	-	556,786,672
Western Wyoming	360-373	WYU	-	-	165,366,883	-	-	165,366,883	-	-	165,366,883
System	360-373	SNPD	-	-	37,730,467	-	-	37,730,467	-	-	37,730,467
System	360-373	CN	-	-	10,802,634	-	-	10,802,634	-	-	10,802,634
System	360-373	SO	-	-	-	-	-	-	-	-	-
System	360-373	SG	-	-	-	-	-	-	-	-	-
System	360-373	OTHER	-	-	-	-	-	-	-	-	-
Total Distribution Plant			-	-	12,166,135,790	-	-	12,166,135,790	-	-	12,166,135,790
Energy Storage Plant											
California	387	CA	-	-	-	-	-	-	-	-	-
Oregon	387	OR	-	-	-	-	-	-	-	-	-
Washington	387	WA	-	-	-	-	-	-	-	-	-
Eastern Wyoming	387	WYP	-	-	-	-	-	-	-	-	-
Utah	387	UT	-	-	-	-	-	-	-	-	-
Idaho	387	ID	-	-	-	-	-	-	-	-	-
Western Wyoming	387	WYU	-	-	-	-	-	-	-	-	-
System	387	CN	-	-	-	-	-	-	-	-	-
System	387	SNPD	-	-	-	-	-	-	-	-	-
System	387	SG	-	-	-	-	-	-	-	-	-
System	387	SO	-	-	-	-	-	-	-	-	-
System	387	OTHER	-	-	-	-	-	-	-	-	-
Total Energy Storage Plant			-	-	-	-	-	-	-	-	-

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Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Sep 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Oct 2027	Capital Additions	Capital Retirements	Adjusted EPIS Balance Nov 2027
General Plant:											
California	397	CA	-	-	16,447,036	-	-	16,447,036	-	-	16,447,036
Oregon	397	OR	-	-	157,119,476	-	-	157,119,476	-	-	157,119,476
Washington	397	WA	-	-	37,601,744	-	-	37,601,744	-	-	37,601,744
Eastern Wyoming	397	WYP	-	-	76,413,290	-	-	76,413,290	-	-	76,413,290
Utah	397	UT	-	-	220,464,973	-	-	220,464,973	-	-	220,464,973
Idaho	397	ID	-	-	43,514,439	-	-	43,514,439	-	-	43,514,439
Western Wyoming	397	WYU	-	-	13,333,699	-	-	13,333,699	-	-	13,333,699
Pre-merger Pacific	397	SG	-	-	473,746	-	-	473,746	-	-	473,746
Pre-merger Utah	397	SG	-	-	1,698,508	-	-	1,698,508	-	-	1,698,508
Post-merger	397	SG	-	-	102,998,979	-	-	102,998,979	-	-	102,998,979
Post-merger	397	SO	-	-	1,070,583,927	-	-	1,070,583,927	-	-	1,070,583,927
Post-merger	397	SG	-	-	-	-	-	-	-	-	-
Post-merger	397	SG	-	-	185,932	-	-	185,932	-	-	185,932
Customer Service	397	CN	-	-	237,053,439	-	-	237,053,439	-	-	237,053,439
Fuel Related	397	SE	-	-	2,538,749	-	-	2,538,749	-	-	2,538,749
Total General Plant			-	-	1,980,427,935	-	-	1,980,427,935	-	-	1,980,427,935
Mining Plant:											
Coal Mine	399	SE	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Mining Plant			-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Intangible Plant:											
Pre-merger Utah	303	SG	-	-	434,408	-	-	434,408	-	-	434,408
Pre-merger Pacific	303	SG	-	-	-	-	-	-	-	-	-
California	303	CA	-	-	469,252	-	-	469,252	-	-	469,252
Customer Service	303	CN	-	-	(3,250,306)	-	-	(3,250,306)	-	-	(3,250,306)
Idaho	303	ID	-	-	4,351,497	-	-	4,351,497	-	-	4,351,497
Oregon	303	OR	-	-	4,596,985	-	-	4,596,985	-	-	4,596,985
Fuel Related	303	SE	-	-	-	-	-	-	-	-	-
Post-merger	303	SG	-	-	196,054,183	-	-	196,054,183	-	-	196,054,183
Post-merger	303	OTHER	-	-	-	-	-	-	-	-	-
Hydro Relicensing	303	SG-P	-	-	103,455,075	-	-	103,455,075	-	-	103,455,075
Hydro Relicensing	303	SG-U	-	-	9,710,888	-	-	9,710,888	-	-	9,710,888
General Office	303	SO	-	-	(14,221,191)	-	-	(14,221,191)	-	-	(14,221,191)
Utah	303	UT	-	-	7,435,969	-	-	7,435,969	-	-	7,435,969
Washington	303	WA	-	-	2,015,954	-	-	2,015,954	-	-	2,015,954
Eastern Wyoming	303	WYP	-	-	5,128,199	-	-	5,128,199	-	-	5,128,199
Western Wyoming	303	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant			-	-	316,180,912	-	-	316,180,912	-	-	316,180,912
Total			-	-	41,693,267,388	-	-	41,693,267,388	-	-	41,693,267,388

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
and Retirements

Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Dec 2027	13-Month Average - December 2027Test Period Balance
Steam Production Plant:						
Pre-merger Pacific	312	SG	-	-	983,781,953	983,865,693
Pre-merger Utah	312	SG	-	-	1,007,859,178	1,008,009,631
Post-merger	312	SG	-	-	5,210,618,243	5,211,761,111
Post-merger	312	SG	-	-	1,266,851	1,266,851
Post-merger	312	SG	-	-	-	-
Post-Merger	312	SG	-	-	-	-
Post-Merger	312	SG	-	-	-	-
Post-merger	312	SG	-	-	-	-
Total Steam Plant			-	-	7,203,526,226	7,204,903,285
Hydro Production Plant:						
Pre-merger Pacific	332	SG	-	-	173,138,332	173,151,980
Pre-merger Utah	332	SG	-	-	39,165,078	39,173,912
Post-merger	332	SG	-	-	13,047,000	13,047,000
Post-merger	332	SG-P	-	-	893,758,783	893,842,714
Post-merger	332	SG-U	-	-	205,858,061	205,791,254
Total Hydro Plant			-	-	1,324,967,254	1,325,006,862
Solar Production Plant:						
Oregon	338XP	OR	-	-	919,203	919,203
Utah	338XP	UT	-	-	558,430	558,487
Post-merger	338XP	SG	-	-	56,322	56,322
Post-merger	338XP	OTHER	-	-	-	-
Total Other Plant			-	-	1,533,956	1,534,013
Wind Production Plant:						
Oregon	338WP	OR	-	-	-	-
Utah	338WP	UT	-	-	-	-
Post-merger	338WP	SG	-	-	3,847,118,070	3,846,439,109
Post-merger	338WP	OTHER	-	-	-	-
Total Other Plant			-	-	3,847,118,070	3,846,439,109
Renewable Production Plant:						
Oregon	339RP	OR	-	-	-	-
Utah	339RP	UT	-	-	-	-
Post-merger	339RP	SG	-	-	159,602,475	159,468,649
Post-merger	339RP	OTHER	-	-	-	-
Total Other Plant			-	-	159,602,475	159,468,649
Other Production Plant:						
Pre-merger Pacific	343	SG	-	-	-	-
Pre-merger Utah	343	SG	-	-	235,129	235,129
Post-merger	343	SG	-	-	2,029,248,215	2,030,327,901
Post-merger	343	SG	-	-	88,298,261	88,311,982
Post-merger	343	SG	-	-	-	-
Total Other Plant			-	-	2,117,781,605	2,118,875,013

Transmission Plant:

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
and Retirements

Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Dec 2027	13-Month Average - December 2027Test Period Balance
California	352	CA	-	-	-	-
Oregon	352	OR	-	-	196,817,185	196,763,820
Washington	352	WA	-	-	-	-
Wyoing	352	WYP	-	-	-	-
Wyoming	352	WYU	-	-	-	-
Utah	352	UT	-	-	-	-
Idaho	352	ID	-	-	-	-
System	355	OTHER	-	-	-	-
Pre-merger Pacific	355	SG	-	-	468,782,323	468,860,623
Pre-merger Utah	355	SG	-	-	598,789,362	598,925,634
Post-merger	355	SG	-	-	11,309,781,396	11,292,994,511
Total Transmission Plant			-	-	12,574,170,265	12,557,544,589
Distribution Plant:						
California	360-373	CA	-	-	831,756,762	827,396,454
Oregon	360-373	OR	-	-	3,565,021,602	3,562,625,448
Washington	360-373	WA	-	-	749,612,645	749,000,099
Eastern Wyoming	360-373	WYP	-	-	946,189,949	944,996,965
Utah	360-373	UT	-	-	5,302,868,174	5,296,719,195
Idaho	360-373	ID	-	-	556,786,672	555,841,103
Western Wyoming	360-373	WYU	-	-	165,366,883	165,391,554
System	360-373	SNPD	-	-	37,730,467	37,730,467
System	360-373	CN	-	-	10,802,634	10,802,634
System	360-373	SO	-	-	-	-
System	360-373	SG	-	-	-	-
System	360-373	OTHER	-	-	-	-
Total Distribution Plant			-	-	12,166,135,790	12,150,503,920
Energy Storage Plant						
California	387	CA	-	-	-	-
Oregon	387	OR	-	-	-	-
Washington	387	WA	-	-	-	-
Eastern Wyoming	387	WYP	-	-	-	-
Utah	387	UT	-	-	-	-
Idaho	387	ID	-	-	-	-
Western Wyoming	387	WYU	-	-	-	-
System	387	CN	-	-	-	-
System	387	SNPD	-	-	-	-
System	387	SG	-	-	-	-
System	387	SO	-	-	-	-
System	387	OTHER	-	-	-	-
Total Energy Storage Plant			-	-	-	-

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
and Retirements

Description	FERC Account	2020P Factor Code	Capital Additions	Capital Retirements	Adjusted EPIS Balance Dec 2027	13-Month Average - December 2027Test Period Balance
General Plant:						
California	397	CA	-	-	16,447,036	16,465,606
Oregon	397	OR	-	-	157,119,476	157,379,400
Washington	397	WA	-	-	37,601,744	37,639,193
Eastern Wyoming	397	WYP	-	-	76,413,290	76,367,888
Utah	397	UT	-	-	220,464,973	220,451,113
Idaho	397	ID	-	-	43,514,439	43,505,285
Western Wyoming	397	WYU	-	-	13,333,699	13,341,805
Pre-merger Pacific	397	SG	-	-	473,746	477,746
Pre-merger Utah	397	SG	-	-	1,698,508	1,711,144
Post-merger	397	SG	-	-	102,998,979	103,346,376
Post-merger	397	SO	-	-	1,070,583,927	1,069,614,314
Post-merger	397	SG	-	-	-	-
Post-merger	397	SG	-	-	185,932	186,085
Customer Service	397	CN	-	-	237,053,439	237,089,255
Fuel Related	397	SE	-	-	2,538,749	2,544,783
Total General Plant			-	-	1,980,427,935	1,980,119,992
Mining Plant:						
Coal Mine	399	SE	-	-	1,822,901	1,822,901
Total Mining Plant			-	-	1,822,901	1,822,901
Intangible Plant:						
Pre-merger Utah	303	SG	-	-	434,408	435,357
Pre-merger Pacific	303	SG	-	-	-	-
California	303	CA	-	-	469,252	469,320
Customer Service	303	CN	-	-	(3,250,306)	(3,178,870)
Idaho	303	ID	-	-	4,351,497	4,351,609
Oregon	303	OR	-	-	4,596,985	4,597,089
Fuel Related	303	SE	-	-	-	-
Post-merger	303	SG	-	-	196,054,183	196,199,896
Post-merger	303	OTHER	-	-	-	-
Hydro Relicensing	303	SG-P	-	-	103,455,075	103,455,075
Hydro Relicensing	303	SG-U	-	-	9,710,888	9,717,774
General Office	303	SO	-	-	(14,221,191)	(13,908,637)
Utah	303	UT	-	-	7,435,969	7,436,155
Washington	303	WA	-	-	2,015,954	2,016,070
Eastern Wyoming	303	WYP	-	-	5,128,199	5,131,280
Western Wyoming	303	WYU	-	-	-	-
Total Intangible Plant			-	-	316,180,912	316,722,118
Total			-	-	41,693,267,388	**41,662,940,450**

Ref 8.5.3

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
Steam Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
NAUGHTON U1 Gas Conversion CY26	312	SG	Dec-26	8,611,894	
NAUGHTON U2 Gas Conversion CY26	312	SG	Dec-26	8,446,211	
GADSBY U3 Generator Stator Rewind	312	SG	May-26	5,370,955	
NAUGHTON U1 OH Field Rewind & Retaining Rings CY25-26	312	SG	Jul-26	5,037,399	
DAVE JOHNSTON U4 - Turbine Major Outage - 2026	312	SG	Various	5,016,127	
NAUGHTON U2 OH Turbine Major HP/IP CY26	312	SG	Jun-26	3,280,851	
GADSBY U3 Generator Field Rewind	312	SG	May-26	3,222,573	
NAUGHTON U1 OH Boiler Overhaul CY26	312	SG	Jun-26	3,175,017	
DAVE JOHNSTON U4 - Turbine Gen EHC Upgrade	312	SG	May-26	2,640,831	
NAUGHTON U0 Water Treatment Replacement CY25-26	312	SG	Dec-26	2,351,548	
HUNTER 301 Air Preheater Baskets	312	SG	Apr-26	2,292,870	
DAVE JOHNSTON U0 - MILL BLANKET - 2026	312	SG	Various	2,218,034	
HUNTINGTON U1 Air Preheater Cold End Baskets - CY2026	312	SG	Oct-26	2,213,887	
NAUGHTON U1 OH Circ Water Line Replacement CY26	312	SG	Jun-26	2,207,455	
HUNTINGTON U1 HP/IP Turbine Component Replacement	312	SG	Nov-26	2,178,957	
DAVE JOHNSTON U4 - RPLC Cooling Tower Refurbishment	312	SG	May-26	2,060,958	
NAUGHTON U2 OH CT Structural Component Replcmt. CY26	312	SG	May-26	2,008,488	
DAVE JOHNSTON U0 - PUMPS AND VALVES - 2026	312	SG	Various	1,996,231	
GADSBY U3 LP Turbine L0 Bucket Replacement	312	SG	Mar-26	1,976,480	
HUNTINGTON U0 Wastewater Pond Mechanical Evaporator	312	SG	Oct-26	1,951,110	
HUNTER 301 Boiler SH Division Panel Replacement	312	SG	Apr-26	1,765,031	
HUNTER 301 FGD Coating Overhaul	312	SG	Apr-26	1,707,622	
HUNTINGTON U1 FGD Tower Liner Replacement	312	SG	Dec-26	1,603,269	
DAVE JOHNSTON U4 - Ovation Evergreen Upgrade 2026	312	SG	May-26	1,591,190	
COLSTRIP COLU5 CCR F CELL LINER CY25-26	312	SG	Dec-26	1,575,389	
DAVE JOHNSTON U4 - REPLACE BAGHOUSE BAGS - 2026	312	SG	May-26	1,517,988	
DAVE JOHNSTON U4 - RPLC BOILER WINGWALL TUBES - 2026	312	SG	May-26	1,434,638	
HUNTER 301 Burner Tips and Nozzles CY26	312	SG	Apr-26	1,309,885	
DAVE JOHNSTON U0 - PUMPS AND VALVES - 2025	312	SG	Various	1,142,337	
HUNTINGTON U1 Burner Corner Coal Nozzle & Tip replacement	312	SG	Dec-26	1,139,616	
WYODAK U1 - In-Plant Silo Refurbishments CY27	312	SG	Feb-27	1,135,821	
NAUGHTON U2 OH Boiler Overhaul CY26	312	SG	Jun-26	1,103,727	
DAVE JOHNSTON U4 - IP FWH Replacement	312	SG	Jun-26	1,070,676	
NAUGHTON U1 OH Stack Recommission/Duct/CEM CY26	312	SG	Jun-26	1,058,339	
NAUGHTON U2 OH Stack Recommission/Duct/CEM CY26	312	SG	Jun-26	1,058,339	
HUNTINGTON U1 Baghouse Bag Replacement Comp 1,2,3	312	SG	Dec-26	1,056,504	
DAVE JOHNSTON U0 316(b) Cooling Water Intake Structure	312	SG	Dec-25	1,056,072	
HUNTER 300 DCS Major Ovation Upgrade - CY23	312	SG	Nov-25	1,028,608	
NAUGHTON BLANKET: U0 - Thermal Run Rate Costs CY25-CY43	312	SG	Various	1,021,473	
NAUGHTON BLANKET: U0 - Motors CY25-CY43	312	SG	Various	1,021,473	
COLSTRIP COLU3 Condenser Tube Replacement CY25	312	SG	Aug-25	1,019,436	
HUNTINGTON U0 CCR Environmental Controls	312	SG	Dec-25	1,012,922	
NAUGHTON U1 OH CT Structural Component Replcmt. CY26	312	SG	May-26	1,004,244	
HUNTER 301 Baghouse Component Overhaul	312	SG	Apr-26	1,000,625	
Projects Less Than $1million	312	SG	Various	82,497,880	
Steam Plant Five Year Average Removals	312	SG	Various	(14,554,697)	
				165,636,281	

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
Hydro Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
IRO P3 South Fork Woodstave Flowline Rep	332	SG-P	Dec-26	18,317,519	8.5.51
Swift 1 Spillway Gate Retrofit	332	SG-P	Dec-26	13,225,839	8.5.51
ILR 11.2.2.12 Beaver Bay Park Redesign p	332	SG-P	Jan-26	11,672,592	8.5.51
Toketee 2 Turbine Refurbishment	332	SG-P	Feb-26	11,256,670	8.5.51
IRO P3 Sag Pipe Replacement	332	SG-P	Dec-26	10,313,705	8.5.52
Cutler Surge Tank Upgrades	332	SG-U	Oct-26	9,342,886	
Yale Spillway Gate Improvements	332	SG-P	Nov-26	8,405,384	
ILR 4.4.1 Swift Fish Exclusion Net	332	SG-P	Nov-25	7,209,567	
Lemolo 2 Flume Refurbishment 2026	332	SG-P	Dec-26	6,330,000	
Swift 1 Spillway Gate Bulkhead	332	SG-P	Dec-26	6,128,530	
Cutler Relicensing	332	SG-U	Nov-25	5,945,492	
Hydro Environmental Emergent Blanket	332	SG-P	Various	4,799,838	
Ashton Trash Rake	332	SG-U	Dec-26	4,747,501	
Oneida B11 Bridge Improvements	332	SG-U	Dec-26	4,491,240	
Merwin Gantry Crane Coating	332	SG-P	Dec-26	2,899,639	
Merwin AWS Pump Install and Overhaul	332	SG-P	Nov-26	2,822,125	
Grace Unit #3 Pivot Valve	332	SG-U	Dec-25	2,093,726	
ILR 11.2.2.2 Saddle Dam Trail Project	332	SG-P	Dec-26	1,957,475	
Swift 1 Switchgear, MCCs and Station Xfmrs Replace	332	SG-P	Dec-26	1,899,000	
Oneida Switchgear	332	SG-U	Jun-26	1,840,409	
ILR 4.3 MerwinTrap Lift Convey Mod	332	SG-P	Oct-26	1,806,319	
Fish Creek Flume Refurbishment	332	SG-P	Nov-26	1,793,500	
Paris Hydro Project Decommissioning	332	SG-U	Dec-25	1,710,266	
ILR 4.4.1 Swift FSC Sample Area Mod.	332	SG-P	Nov-26	1,623,842	
Lemolo No. 2 Forebay Trash Rake	332	SG-P	Aug-25	1,341,599	
IRO P3 Auxiliary Minimum Flow Supply Sys	332	SG-P	Dec-26	1,269,360	
Hydro Surveillance Camera Replacements Blanket	332	SG-P	Various	1,107,750	
Speelyai Water Supply Pipe Replacement	332	SG-P	Oct-26	1,080,058	
Cutler Implementation (10-Year)	332	SG-U	Dec-26	1,055,000	
Yale Dam Monitoring ADAS System	332	SG-P	Nov-25	1,013,250	
Projects Less Than $1million	332	SG-P	Various	32,773,702	
Projects Less Than $1million	332	SG-U	Various	7,721,918	
Hydro Plant Five Year Average Removals	332	SG-P	Various	(2,485,149)	
Hydro Plant Five Year Average Removals	332	SG-U	Various	(1,240,418)	
				186,270,136	

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
Solar Production Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
None					
Projects Less Than $1million	338XP	SG	Various	-	
Projects Less Than $1million	338XP	OR	Various	148,724	
Projects Less Than $1million	338XP	UT	Various	-	
Other Plant Five Year Average Removals	338XP	UT	Various	(2,586)	
				146,138	

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
Wind Production Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
W-1799 LTSA CONTRACTS	338WP	SG	Various	19,338,250	
W-1799 WTG MAJOR COMPONENTS BLANKET	338WP	SG	Various	8,544,930	
W-1760 INSTALL AUTO AVIAN CRTLMNT SYSTEM	338WP	SG	Dec-26	2,265,408	
W-1799 EAGLE MITIGATION BLANKET	338WP	SG	Various	2,228,348	
W-1745 INSTALL AUTOMATED AVIAN CURTAILMENT SYSTEM	338WP	SG	Dec-26	2,057,250	
ROCK RIVER - ACQUIRE REPOWER	338WP	SG	Nov-26	2,043,736	
W-1799 WTG SMALL COMPONENTS BLANKET	338WP	SG	Various	1,351,998	
Foote Creek 2-4 Repowering	338WP	SG	Dec-26	1,272,006	
W-1799 ROAD & BANK STABILIZATION BLANKET	338WP	SG	Various	1,043,268	
Projects Less Than $1million	338WP	SG	Various	3,430,864	
Projects Less Than $1million	338WP	SSGCT	Various	-	
Other Plant Five Year Average Removals	338WP	SG	Various	(2,257,735)	
				41,318,323	

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
Renewable Production Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
None					
Projects Less Than $1million	338RP	SG	Various	1,775,726	
Renewable Plant Five Year Average Removals	338RP	SG	Various	-	
				1,775,726	

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
Other Production Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
CURRANT CREEK U1 CT Rotor Replacement CY25-26	343	SG	Dec-26	19,763,586	8.5.53
CURRANT CREEK U2 CT Rotor Replacement CY25-26	343	SG	Dec-26	19,763,586	8.5.53
CURRANT CREEK U1 CSA Variable fee 32k - CTA HGP CY26	343	SG	Apr-26	15,250,324	8.5.53
CURRANT CREEK U2 CSA Variable fee 32k - CTB HGP CY26	343	SG	Apr-26	15,250,324	8.5.53
HERMISTON HERMU1 Rotor Replacement CY26	343	SG	Dec-26	7,838,912	
HERMISTON HERMU1 Overhaul Capital CY26 MI	343	SG	Nov-26	7,181,573	
HERMISTON HERMU1 Combustion Turbine DLN 2.6e Upgra	343	SG	Dec-26	4,269,778	
HERMISTON HERMU2 Combustion Turbine DLN 2.6e Upgra	343	SG	Dec-25	4,069,294	
HERMISTON HERM Addl Capital Upgrades/Repl CY26	343	SG	Dec-26	2,518,285	
HERMISTON HERMU2 Overhaul Capital CY25 HGP	343	SG	Nov-25	2,117,416	
HERMISTON HERMU0 Cap Spares - CT S1N, S3N, S1S	343	SG	Dec-25	1,016,575	
Projects Less Than $1million	343	SG	Various	7,035,262	
Projects Less Than $1million	343	SSGCT	Various	39,177	
Other Plant Five Year Average Removals	343	SG-W	Various	(1,902,763)	
				104,211,329	

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
Transmission Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
Project Litespeed	352	OR	Various	135,010,262	8.5.54
Customer 57 - Trans - Q2913	355	SG	Various	95,321,062	8.5.56
PP Trans - OH Trans Poles, Trans Storm & Casualty, Trans Tree Poles, (	355	SG	Various	53,130,556	
Gateway South Aeolus Mona 500kV Line	355	SG	Dec-24	46,598,071	8.5.56
EDAM (Energy Day Ahead Market System)	355	SG	Aug-26	43,356,243	8.5.56
Wildfire Mitigation - Trans	355	SG	Various	36,045,418	
Customer 7 - Trans - OR	352	OR	Various	30,905,224	8.5.57
Project Specialized	352	OR	Various	30,901,699	8.5.57
Camp Williams 345-138 kV Transformer and 138 kV Yard Additions	355	SG	Dec-25	30,162,305	8.5.57
Generation Interconnection East	355	SG	Various	28,372,388	
St Johns (BPA) to Knott 115kV Line Conversion Project	355	SG	Various	28,136,691	8.5.57
Aeolus Sub Transformer Event Resolution	355	SG	Aug-25	27,890,101	8.5.57
Malin - Bonanza New 69 kV Line	355	SG	Various	25,247,257	8.5.58
Pomona Heights 230-115 kV Transformers Replacement TPL	355	SG	Various	23,465,826	8.5.58
Wildfire - Trans - PP - Line Rebuild	355	SG	Various	22,662,043	
Wildfire Mitigation - Trans	355	SG	Various	20,227,714	
Scoville Sub Relocate	355	SG	May-26	18,601,910	8.5.58
Customer 65 - Trans - Q0787	355	SG	Sep-25	17,737,943	8.5.58
Loop 90 South - Terminal into MidValley 345 line	355	SG	Feb-26	16,836,333	8.5.58
Customer 60 - Trans - Q634	355	SG	Oct-26	14,641,324	8.5.58
Customer 81 - Trans - OTP Q0258	355	SG	Feb-27	14,349,424	8.5.58
GWS Supporting Projects	355	SG	Various	14,004,262	8.5.59
Windstar–Shirley Basin D1 230kV Trans Ln	355	SG	Dec-24	13,839,446	8.5.59
Replace Overhead Transmission Poles - UT	355	SG	Various	12,885,746	
Hurricane Sub: New Spare 230-69 kV, 25 MVA Trans	355	SG	Dec-26	12,179,822	8.5.59
FERC Order 881 Mandate Upgrades	355	SG	Dec-26	11,743,086	8.5.59
Oquirrh Terminal 345kV Line	355	SG	Oct-25	11,584,404	8.5.59
Replacements Investment Programs - T - UT	355	SG	Various	11,080,555	
Walla Walla 69kV Loop Reconfigure and Reconductor	355	SG	Various	10,975,982	8.5.59
Dixonville Sub Replace Transformer T-3112	355	SG	Nov-25	10,141,463	8.5.59
Customer 72 - Trans - Q953	355	SG	Mar-27	9,725,757	
Customer 75 - Trans - OTP188	355	SG	Feb-26	9,459,567	
Replace Overhead Transmission Lines - Other - UT	355	SG	Various	9,355,338	
Customer 76 - Trans - OTP196	355	SG	Sep-25	9,094,974	
Banfield New 115kV to 12.5kV Substation	355	SG	Jun-26	8,884,859	
Weirich to BPA Lebanon 115 kV Tie	355	SG	Various	8,312,301	
Customer 42 - Trans - UT - SG	355	SG	Various	7,990,672	
Wildfire Mitigation Plan - CA T	355	SG	Various	7,149,503	
HUNTINGTON U0 Universal Spare GSU Huntington Plant	355	SG	Jun-26	7,119,473	
HUNTER 301 Main Transformer GSU Purchase	355	SG	Apr-26	6,982,061	
Tucker 69 kV Tie Line	355	SG	Various	6,623,693	
Circuit Breaker and Recloser Replacement Program	355	SG	Various	6,543,568	
Gadsby - Replace Failed Xfmr #10	355	SG	Nov-25	6,500,000	
Replace - Storm & Casualty - Trans UT	355	SG	Various	6,274,473	
Customer 68 - Trans - Q815	355	SG	Sep-26	5,883,548	
Upgrades Investment Programs - T - UT	355	SG	Various	5,805,348	
Line 30 & 65 Convert to 115 kV	355	SG	Various	5,460,147	
BIA Fort Hall Jim Bridger-Kinport 345kV (North/South)	355	SG	Dec-25	5,351,911	
Camp Williams – Mona #1 345 kV Clearance Improvement	355	SG	Nov-25	5,100,000	
FAC-008 Settlement -Reliability Enhancement Project	355	SG	Aug-25	5,026,285	
WP West Acquisitions-ACC Burial on 100S	355	SG	Various	4,958,255	
BLM Various Forest Wasatch Cache National Forest - 2026	355	SG	Dec-26	4,820,934	
Mobile #6 Replace Failed 138-69kV Transf	355	SG	Oct-25	4,600,000	
DJ-Deer Creek-Big Muddy Rebuild	355	SG	Dec-25	4,424,573	
Custpmer 66 - Trans - Q799	355	SG	Nov-26	4,325,331	
Customer 59 - Trans - C1-5	355	SG	Various	4,313,199	
Camp Williams-Mona #1 and #3 345 kV Separation	355	SG	Jul-25	4,251,808	

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
Transmission Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
Smith/Bybee Lake Pole Replacements	355	SG	Various	4,177,220	
Customer 55 - Trans - WY - SG	355	SG	Dec-26	3,965,266	
Gateway Completed project close out	355	SG	Oct-15	3,920,292	
Reroute JB Goshen 345kV line for Slide: IPC Shared	355	SG	Nov-26	3,679,624	
BIA Camp Williams 4 Corners - Ute Mtn Tribal - 2025	355	SG	Dec-25	3,598,410	
Replacements Investment Programs - T - ID	355	SG	Various	3,483,932	
Mountain Green New Substation - Trans	355	SG	Jul-26	3,430,246	
Clover Series Reactor Bypass Breaker	355	SG	Jan-26	3,387,653	
Replace Overhead Transmission Lines - Other - ID	355	SG	Various	3,178,593	
Moab-Pinto 138 kV: Install Auto Rollover	355	SG	Oct-25	3,084,671	
Custpmer 73 - Trans - Q1008	355	SG	Mar-27	2,940,178	
Replacements Investment Programs - T - WY	355	SG	Various	2,878,300	
Albina Troutdale Line Rebuild	355	SG	Dec-26	2,871,839	
Customer 70 - Trans - Q0836	355	SG	Aug-25	2,861,464	
Brunswick: Repl XFMR #1 & 46kV UG Cabler	355	SG	Nov-25	2,759,532	
Customer 80 - Trans - AS016	355	SG	Oct-25	2,726,672	
Customer 62 - Trans - Q0713	355	SG	Jan-25	2,720,020	
SF6 - Circuit Breaker Replacements - T - UT	355	SG	Various	2,586,761	
Houston Lake-Ponderosa Add Second 115kV Line	355	SG	Nov-25	2,556,281	
System Automation - Reclosers, Relays	355	SG	Various	2,518,005	
Replace Overhead Transmission Lines - Other - WY	355	SG	Various	2,445,076	
Meridian RAS Expansion	355	SG	Oct-26	2,378,834	
Franklin Substation 25 MVAR Shunt Capacitor TPL	355	SG	Nov-26	2,361,415	
Replace Overhead Transmission Poles - ID	355	SG	Various	2,196,594	
Yellowtail Casper BIA CROW	355	SG	Sep-26	2,137,082	
Downtown 8kV System Upgrade - Trans	355	SG	Dec-26	2,118,337	
Cutler-El Monte Line Relocation with Brigham City	355	SG	Dec-26	2,100,404	
BIA Crow Billings Yellowtail - Yellowtail Casper 2310(1192)	355	SG	Jul-26	2,071,404	
BIA Crow Tribe Billings Yellowtail - Yelllowtail Thermopolis 2310(1181)	355	SG	Jul-26	2,021,285	
Customer 35 - Trans - UT - SG	355	SG	Mar-26	1,925,014	
US BIA-Crow Billings-Yellowtail 2310(1180)	355	SG	Sep-26	1,914,606	
Customer 58 - Trans - C1-5-34	355	SG	Dec-26	1,897,485	
HUNTER 301 Main GSU Replacement	355	SG	Aug-26	1,827,839	
Customer 69 - Trans - Q0838	355	SG	Jun-25	1,811,265	
BLM & Other ROW Renewals - T - UT	355	SG	Various	1,808,638	
Replace - Storm & Casualty - Trans ID	355	SG	Various	1,736,423	
PP Transmission	355	SG	Various	1,726,631	
Replace Overhead Transmission Poles - WY	355	SG	Various	1,647,446	
TPL Overdutied Circuit Breaker Replacements	355	SG	Various	1,560,180	
Mandated Investment Programs - T - UT	355	SG	Various	1,549,032	
St George SVC HMI Upgrade	355	SG	Jun-26	1,521,295	
Replace Substation Bushings, Glass & Other - T - UT	355	SG	Various	1,421,588	
Customer 22 - Trans - UT - SG	355	SG	Dec-26	1,302,459	
Helper Substation Expansion for Mobile Connection	355	SG	Dec-25	1,251,285	
Mandated Highway Relocations - T - UT	355	SG	Various	1,126,690	
Transmission Breakers	355	SG	Various	1,119,706	
North Salt Lake Conversion - Trans	355	SG	May-26	1,109,080	
Projects Less Than $1million	355	SG	Various	22,168,934	
Transmission Plant Five Year Average Removals	355	SG	Various	(14,021,689)	
				1,161,931,439	

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
Wildfire - Dist - CA - Line Rebuild	360-373	CA	Various	205,889,851	
Wildfire Mitigation - Dist - UT	360-373	UT	Various	198,283,228	
Portland Willamette River Crossing	360-373	OR	Feb-26	194,071,494	8.5.60
OR New Connect OR - Residential, Commercial, Irrigation, Street Light &	360-373	OR	Various	93,178,269	
Wildfire Mitigation - Dist UT	360-373	UT	Various	76,891,485	
Utah-New Connect - Residential	360-373	UT	Various	54,674,036	
Oregon Replace OH Dist Lines - Poles	360-373	OR	Various	41,598,314	
Replace Overhead Distribution Poles - UT	360-373	UT	Various	41,209,942	
Replacements Investment Programs - D - UT	360-373	UT	Various	40,450,308	
Customer 34 - Dist - UT	360-373	UT	Various	39,628,002	
New Connect Investment Programs - D - UT	360-373	UT	Various	37,943,926	
Utah-New Connect - Commercial	360-373	UT	Various	36,398,059	
Wildfire Mitigation - Dist - WY	360-373	WYP	Various	24,866,289	
Replace Underground Vaults & Equipment - UT	360-373	UT	Various	24,820,876	
Customer 21 - Dist -UT	360-373	UT	Dec-26	24,326,530	
Wildfire Mitigation - Dist WY	360-373	WYP	Various	22,775,618	
North Logan 138-12.5 kV Greenfield Substation	360-373	UT	Various	21,193,475	
Oregon Replace Storm and Casualty	360-373	OR	Various	20,378,616	
Replace Overhead Distribution Lines - Other - UT	360-373	UT	Various	18,988,687	
Holladay XFMR 2 Upgrade to 30 MVA - Dist	360-373	UT	Dec-26	18,636,997	
Customer 43 - Dist - WY	360-373	WYP	Nov-26	18,303,666	
PP New Connect WA - Residential, Commercial, Irrigation, Street Light &	360-373	WA	Various	17,561,435	
Mountain Green New Substation - Dist	360-373	UT	Jul-26	17,192,899	
Customer 54 - Dist - UT	360-373	UT	Various	16,624,585	
Customer 25 - Dist - UT	360-373	UT	Various	14,758,460	
Customer 17 - Dist - UT	360-373	UT	Oct-26	14,359,658	
System Automation - Reclosers, Relays	360-373	CA	Various	14,274,604	
New Revenue - Feeder Reinforcement - UT	360-373	UT	Various	13,388,869	
Yew Ave Capacity Increase	360-373	OR	Various	13,268,276	8.5.60
Customer 31 - Dist - UT	360-373	UT	Dec-25	12,641,984	
Customer 23 - Dist - UT	360-373	UT	Various	11,989,776	
PP Distribution OR - Dist Rplc. sub switchgear, meters, replacement	360-373	OR	Various	11,911,497	
Jumbers Point Substation - Dist	360-373	UT	May-26	11,543,515	
Syracuse 138-13.2 kV Transformer	360-373	UT	Sep-25	11,450,858	
Rebuild Deer Creek Substation	360-373	WYP	Dec-25	11,397,464	
New Connect Meters - New and Replacements - UT	360-373	UT	Various	11,128,647	
Bond Street Add 2nd Transformer	360-373	OR	Various	10,991,841	8.5.60
Replace Overhead Distribution Poles - ID	360-373	ID	Various	10,541,507	
Warren Transformer Addition	360-373	UT	Various	10,529,724	
Replace Overhead Distribution Lines - Crossarms & Cutouts - Dist - UT	360-373	UT	Various	10,361,349	
Dixonville T-3843 replacement	360-373	OR	Sep-26	10,121,396	8.5.60
Oregon - Mandated Highway Relocations	360-373	OR	Various	9,867,700	
CA New Connect CA - Commercial, Residential, Irrigation, Street Light &	360-373	CA	Various	9,037,759	
Customer 28 - Dist - UT	360-373	UT	May-26	8,887,310	
Customer 37 - Dist - UT	360-373	UT	May-26	8,787,438	
Nibley 138/12 kV Transformer Addition	360-373	UT	Oct-25	8,731,508	
Mandated Highway Relocations - D - UT	360-373	UT	Various	8,707,301	
North Salt Lake Conversion - Dist	360-373	UT	May-26	8,364,653	
Mandated Investment Programs - D - UT	360-373	UT	Various	8,318,580	
Elkhorn Install T#2, 30 MVA	360-373	WYP	May-26	8,172,632	
Replace Overhead Distribution Poles - WY	360-373	WYP	Various	8,063,803	
Spare Transformers -TBD by study or TRF failure	360-373	OR	Various	8,011,006	
Customer 48 - Dist - UT	360-373	UT	Dec-26	7,883,062	
Unspecified OR Distribution Reinforcement	360-373	OR	Various	7,307,545	
Silver Creek Install Distribution Transformer	360-373	UT	Dec-26	6,932,636	
Customer 20 - Dist - UT	360-373	UT	May-26	6,896,776	
Walnut Grove Transformer Addition	360-373	UT	May-26	6,847,695	
Customer 40 - Dist - UT	360-373	UT	Various	6,750,000	
Wash Replace OH Dist Lines - Poles	360-373	WA	Various	6,716,207	
Replace Underground Cable - UT	360-373	UT	Various	6,705,845	

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
Tieton Substation Capacity Increase	360-373	WA	May-26	6,696,567	
Customer 14 - Dist - UT	360-373	UT	Various	6,553,172	
Idaho-New Connect - Residential	360-373	ID	Various	6,516,445	
Rigby 161-12kV Transformer Addition	360-373	ID	Various	6,363,222	
Customer 1 - Dist - OR	360-373	OR	Nov-26	6,297,817	
Replacements Investment Programs - D - WY	360-373	WYP	Various	6,195,602	
Oregon Replace Overhead Dist Lines/Other	360-373	OR	Various	6,179,111	
Customer 15 - Dist - UT	360-373	UT	May-26	6,074,706	
Customer 2 - Dist - OR	360-373	OR	Nov-26	5,886,257	
China Hat Substation Increase Capacity	360-373	OR	Oct-26	5,860,678	
Replace - Storm & Casualty - Dist UT	360-373	UT	Various	5,666,334	
Customer 30 - Dist - UT	360-373	UT	Various	5,529,761	
Customer 46 - Dist - UT	360-373	UT	Dec-25	5,468,778	
Mobile 161-13.2kV 33MVA Xfmr	360-373	ID	Dec-26	5,446,806	
New Connect Investment Programs - D - ID	360-373	ID	Various	5,392,523	
California Replace OH Dist Lines - Poles	360-373	CA	Various	5,263,322	
Ruby 69-12.5kV 14MVA Transformer Replacement	360-373	ID	Sep-25	5,241,046	
Fayette T#1 Install Third 333 kVA	360-373	UT	Jul-26	5,239,831	
Oregon Cross-Arms & Cutouts RD	360-373	OR	Various	5,192,659	
Wyoming-New Connect - Commercial	360-373	WYP	Various	5,182,161	
Wyoming-New Connect - Residential	360-373	WYP	Various	5,154,487	
New Connect Investment Programs - D - WY	360-373	WYP	Various	4,964,871	
Customer 8 - Dist - UT	360-373	UT	Various	4,810,698	
Spare 230-34.5kV 125 MVA XFMR w/LTC (Rock Springs 2021B)	360-373	WYP	Dec-25	4,788,150	
TPU/DPU Relay Replacement Program - UT (DOE)	360-373	UT	Various	4,650,512	
Medford 115-12.5kV Capacity Increase	360-373	OR	Aug-25	4,608,762	
Oregon Cross-Arms & Cutouts RI	360-373	OR	Various	4,576,709	
Replacements Investment Programs - D - ID	360-373	ID	Various	4,300,422	
Customer 5 - Dist - CA	360-373	CA	Dec-26	4,279,520	
Spare 115-34.5kV - 30MVA unit	360-373	WYP	Nov-26	4,075,804	
MEDFORD TO PURCHNEW MOBILE SUB	360-373	OR	Various	3,838,605	
Customer 41 - Dist - UT	360-373	UT	Dec-25	3,801,218	
Customer 4 - Dist - OR	360-373	OR	Various	3,306,397	
Upgrades Investment Programs - D - UT	360-373	UT	Various	3,246,916	
Customer 11 - Dist - UT	360-373	UT	Dec-25	3,186,120	
Banfield New 115kV to 12.5kV Substation	360-373	OR	Jun-26	3,174,857	
Customer 53 - Dist - UT	360-373	UT	Dec-26	3,174,662	
PP Distribution WA	360-373	WA	Various	3,125,539	
Fuses	360-373	CA	Various	3,110,840	
Customer 36 - Dist - UT	360-373	UT	Sep-25	3,100,000	
Replace Overhead Distribution Lines - Other - WY	360-373	WYP	Various	3,086,047	
New Harmony Upgrade Transformer	360-373	UT	Aug-25	2,982,942	
Avian Protection - Dist ID	360-373	ID	Various	2,960,184	
Calif Replace Storm and Casualty	360-373	CA	Various	2,953,068	
Avian Protection - Dist WY	360-373	WYP	Various	2,903,602	
Customer 56 - Dist - WY	360-373	WYP	Dec-26	2,828,571	
West Valley Install Second Xfmr	360-373	UT	Various	2,771,296	
Spare 138-34.5kV 30MVA Xfmr (Parowan Tech Ops 2022A)	360-373	UT	Dec-25	2,679,560	
Dorris Sub- Capacity Solution-Transformer 9.4 MVA	360-373	CA	Nov-25	2,668,358	
Replace Overhead Distribution Lines - Crossarms & Cutouts - Dist - WY	360-373	WYP	Various	2,647,618	
Mandated Joint Use - UT	360-373	UT	Various	2,639,851	
Idaho-New Connect - Commercial	360-373	ID	Various	2,570,072	
Avian Protection - Dist UT	360-373	UT	Various	2,461,459	
Mandated OH/UG Conversions - UT	360-373	UT	Various	2,461,421	
Washington- Mandated Highway Relocations	360-373	WA	Various	2,396,274	
Fibercrete vault replacement - UT	360-373	UT	Various	2,384,033	
Customer 16 - Dist - UT	360-373	UT	Oct-25	2,368,991	
System Reinforcement Investment Programs - D - UT	360-373	UT	Various	2,365,026	
Replace Underground Cable - WY	360-373	WYP	Various	2,258,231	
Wildfire Mitigation - Dist ID	360-373	ID	Various	2,253,066	

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
Customer 29 - Dist - UT	360-373	UT	Sep-25	2,249,907	
Customer 50 - Dist - UT	360-373	UT	Dec-25	2,237,483	
Wildfire Mitigation - Dist - ID	360-373	ID	Various	2,144,883	
Purch 69-24.9x13.2kV (14MVA) Spare Xfmr (Hoopes)	360-373	UT	Sep-25	2,104,474	
Mandated Public Accommodations & Other - D - UT	360-373	UT	Various	2,082,340	
Wash Replace Storm and Casualty	360-373	WA	Various	2,063,997	
Spanish Fork Sub Install Transformer	360-373	UT	Various	2,040,306	
Replace Overhead Distribution Lines - Other - ID	360-373	ID	Various	1,989,850	
Washington Replace Underground Cable	360-373	WA	Various	1,948,424	
Replace - Storm & Casualty - Dist WY	360-373	WYP	Various	1,937,833	
PP Distribution CA - Dist Rplc. sub switchgear, meters, replacement	360-373	CA	Various	1,931,602	
Utah-New Connect-Str Light & Otr	360-373	UT	Various	1,915,749	
Siren Crew Callout	360-373	SNPD	Apr-26	1,883,228	
Replace Underground Cable - ID	360-373	ID	Various	1,867,855	
Customer 3 - Dist - OR	360-373	OR	Nov-26	1,823,423	
U/G Cable Test & Replace	360-373	UT	Various	1,798,234	
Wash Replace Overhead Dist Lines/Other	360-373	WA	Various	1,782,975	
Westwood Sub New Distribution Circuit	360-373	ID	May-26	1,720,563	
Distribution Breakers	360-373	UT	Various	1,679,343	
New Revenue - Feeder Reinforcement - WY	360-373	WYP	Various	1,662,515	
New Connect Meters - New and Replacements - ID	360-373	ID	Various	1,598,276	
Customer 52 - Dist - UT	360-373	UT	Dec-26	1,558,874	
AMR Meters Calendar - UT	360-373	UT	Various	1,552,450	
Net Metering Installation UT	360-373	UT	Various	1,507,866	
Customer 49 - Dist - UT	360-373	UT	May-26	1,503,721	
Replace - Storm & Casualty - Dist ID	360-373	ID	Various	1,460,969	
Dist. cFCI - Sentient AMPLE SaaS	360-373	UT	Various	1,383,636	
Replace Overhead Distribution Lines - Crossarms & Cutouts - Dist - ID	360-373	ID	Various	1,311,357	
Rogue River Substation Capacity Increase	360-373	OR	Oct-26	1,298,172	
Mallory Substation Add Feeder Position	360-373	OR	Oct-26	1,252,482	
California Cross-Arms & Cutouts RD	360-373	CA	Various	1,237,447	
Replace Underground Vaults & Equipment - WY	360-373	WYP	Various	1,217,856	
Customer 33 - Dist - UT	360-373	UT	Oct-25	1,201,491	
Walla Walla 69kV Loop Reconfigure and Reconductor	360-373	WA	Various	1,199,450	
Distribution Recloser (SCAN)	360-373	UT	Various	1,160,917	
RMP New Spare 69-13.2kV (7.5MVA) Transformer (Terminal TO 2023A)	360-373	UT	Oct-25	1,100,000	
Replace - Storm & Casualty - Crossarms & Cutouts - Dist - UT	360-373	UT	Various	1,082,506	
Mandated Highway Relocations - D - ID	360-373	ID	Various	1,074,655	
New Revenue - Feeder Reinforcement - ID	360-373	ID	Various	1,052,073	
Mandated Investment Programs - D - WY	360-373	WYP	Various	1,044,479	
Downtown 8kV System Upgrade - Dist	360-373	UT	Various	1,036,848	
S. UT TechOps 2022A, 46-12.5kV 7MVA Xfmr (Terminal TO 2022C)	360-373	UT	Oct-25	1,005,000	
Projects Less Than $1million	360-373	UT	Various	(36,951,165)	
Projects Less Than $1million	360-373	ID	Various	6,057,484	
Projects Less Than $1million	360-373	WYP	Various	8,376,929	
Projects Less Than $1million	360-373	OR	Various	1,209,541	
Projects Less Than $1million	360-373	WA	Various	4,411,859	
Projects Less Than $1million	360-373	CA	Various	2,419,295	
Distribution Plant Five Year Average Removals	360-373	ID	Various	(2,868,142)	
Distribution Plant Five Year Average Removals	360-373	WA	Various	(5,065,817)	
Distribution Plant Five Year Average Removals	360-373	WYP	Various	(6,694,494)	
Distribution Plant Five Year Average Removals	360-373	OR	Various	(24,725,754)	
Distribution Plant Five Year Average Removals	360-373	UT	Various	(33,589,727)	
Distribution Plant Five Year Average Removals	360-373	CA	Various	(6,093,718)	
				1,882,888,827	

PacifiCorp
Oregon General Rate Case - December 2027
Pro Forma Plant Additions
General Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
Willamette Ops Center	397	SO	Various	10,800,000	8.5.60
VMWare Replacement - Lic via BHE	397	SO	Dec-25	8,018,216	
OT STS Security Tools Standardization Project	397	SO	Dec-26	6,291,429	
PP Structures OR	397	OR	Various	6,098,718	
PP General Plant OR - Rebuild Computers/Office Equipment & Replace Tools	397	SO	Various	5,805,434	
PacifiCorp Accelerated RTU Replacement (PARR)	397	SO	Various	5,378,354	
OT Network/Security (less centralized Firewall)	397	SO	Various	5,078,484	
North Temple Campus Redevelopment	397	UT	Various	4,017,002	
Replace Tools - UT	397	UT	Various	3,959,909	
Utility Network - Connectivity system migration, implementation, integration	397	SO	Various	3,618,731	
Oregon Replace Deteriorated Vehicles	397	OR	Various	3,320,413	
Replace Other General Plant - UT	397	UT	Various	3,246,338	
AIX Obsolescence Management	397	SO	6/30/2026	3,240,000	
Local PC TOM	397	SO	Various	3,195,369	
Palo Alto Licensing for Security	397	SO	Sep-25	3,115,075	
Storage capacity and obsolescence management	397	SO	Annual	2,941,573	
Replace Vehicles - UT	397	UT	Various	2,927,286	
Eng Telecom Replace Other Communications	397	SO	Various	2,913,918	
Integrated Construction Management System and As-Built Capture System	397	SO	Various	2,860,007	
Data Center Consolidation	397	SO	Various	2,738,880	
Palo Alto Licensing for OTN-BHE	397	SO	Sep-25	2,692,818	
PARR (Accelerated RTU replacement) (IJ, future R9)	397	SO	Various	2,692,030	
Eng Telecom PP Replace Transport	397	SO	Various	2,622,526	
Window server capacity & obsolescence mgt	397	SO	Various	2,559,060	
Situational Awareness (Large Software Subscriptions)	397	UT	Various	2,449,090	
Replace Other General Plant - WY	397	WYP	Various	2,403,095	
Transmission & Distribution and GIS	397	SO	Various	2,398,560	
Identity Governance Admin.-Saviynt (Phase 2)	397	SO	Dec-26	2,124,614	
Security Software	397	SO	Various	2,002,193	
GeoDigital Vegetation Management	397	SO	Oct-25	1,943,660	
PAC Genesys Cloud Migration - CB	397	SO	Dec-26	1,932,591	
Eng Telecom RMP R9 (Replace Other Comm)	397	SO	Various	1,913,351	
2025 SCADA PARR East	397	SO	Dec-25	1,762,724	
Corporate Network Lifecycle - JL	397	SO	Various	1,674,000	
Wildfire Mitigation - Gen Situs - UT	397	UT	Various	1,610,877	
Eng Telecom PP Upgrade Transport	397	SO	Various	1,588,567	
Oracle CC Doc Mgmt. WCC WebCMS	397	SO	Jan-26	1,500,000	
Replacements Investment Programs - Situs G - UT	397	UT	Various	1,449,818	
2025 Data Domain SLC	397	SO	9/30/2025	1,403,088	
SCADA PARR Program East	397	SO	12/31/2025	1,342,013	
VDI growth / TOMS	397	SO	12/31/2026	1,296,000	
Replace Other General Plant - ID	397	ID	Various	1,178,142	
OTLM Replace Legacy Telecom Circuits	397	SO	Various	1,165,567	
OT Privileged Access Management-	397	SO	3/31/2027	1,150,237	
PP General Plant WA - Rebuild Computers/Office Equipment & Replace Tools	397	SO	Various	1,072,580	
Miscellaneous Corporate Telecom Projects	397	SO	Dec-25	1,058,067	
Eng Telecom RMP R8 (Replace Transport)	397	SO	Various	1,043,647	
BHE OT STS Foundation HW Ph 1	397	SO	10/31/2025	1,037,980	
Linux capacity and obsolescence management	398	SO	Annual	1,023,624	
Projects Less Than $1million	397	SO	Various	31,947,610	
Projects Less Than $1million	397	WYP	Various	5,174,860	
Projects Less Than $1million	397	UT	Various	2,211,289	
Projects Less Than $1million	397	ID	Various	1,611,961	
Projects Less Than $1million	397	WA	Various	1,502,542	
Projects Less Than $1million	397	SG	Various	-	
Projects Less Than $1million	397	OR	Various	845,160	
Projects Less Than $1million	397	CA	Various	793,581	
General Plant Five Year Average Removals	397	SO	Various	(1,213,489)	
				182,529,170	

PacifiCorp
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Pro Forma Plant Additions
Intangible Plant Additions

Project Description	FERC Account	Factor	Inservice Date	Jul25 to Mar27 Plant Adds	Ref.
None					
Projects Less Than $1million	303	SO	Various	-	
				-	

PacifiCorp
Oregon General Rate Case - December 2027
Plant Retirements
5 Year Average Retirement Amount

Function	Factor	FY2021 (CY2020) Retirements	FY2022 (CY2021) Retirements	FY2023 (CY2022) Retirements	FY2024 (CY2023) Retirements	FY2025 (CY2024) Retirements	Large Items to Exclude	5 Year Avg	Monthly Amount
STMP	DGU	(2,191,253)	(2,596,560)	(4,405,413)	(4,912,313)	(5,453,227)	-	(3,911,753)	(325,979)
STMP	DGP	(2,667,943)	(3,146,449)	(2,475,103)	(1,811,671)	(19,715,210)	18,930,206	(2,177,234)	(181,436)
STMP	SSGCH				-	-	-	-	-
STMP	SG	(30,626,315)	(29,922,896)	(59,114,223)	(49,138,343)	(80,560,719)	58,667,407	(38,139,018)	(3,178,251)
STMP	NUTIL	-	(29,653,867)	(534,481)	(161,978)	-	-	(6,070,065)	(505,839)
		(35,485,512)	(65,319,772)	(66,529,220)	(56,024,304)	(105,729,156)	77,597,613	(50,298,070)	(4,191,506)
HYDP	SG-U	(596,216)	(361,746)	(685,344)	(542,544)	(208,573)	-	(478,884)	(39,907)
HYDP	SG-P	(4,743,569)	(1,821,775)	(73,605,770)	(2,034,890)	(4,434,194)	73,806,116	(2,566,817)	(213,901)
HYDP	DGU	(819,933)	(100,113)	(171,368)	(38,384)	(18,699)	-	(229,699)	(19,142)
HYDP	DGP	(703,798)	(89,052)	(29,202,213)	(305,789)	(9,001,668)	37,528,289	(354,846)	(29,571)
HYDP	NUTIL	-	-	-	-	-	-	-	-
		(6,863,517)	(2,372,686)	(103,664,695)	(2,921,607)	(13,663,134)	111,334,405	(3,630,247)	(302,521)
OTHP	DGU						-	-	-
OTHP	SG	(462,843,749)	(63,782,871)	(21,557,803) #	(28,993,089)	(14,124,910)	450,972,954	(28,065,893)	(2,338,824)
OTHP	SG-W	-	-	-	-	-	-	-	-
OTHP	SSGCT	-	(38,029)	(1,745,767)	-	-	-	(356,759)	(29,730)
OTHP	NUTIL	-	(3,531,744)	-	-	-	-	(706,349)	(58,862)
		(462,843,749)	(67,352,644)	(23,303,570)	(28,993,089)	(14,124,910)	450,972,954	(29,129,001)	(2,427,417)
TRNP	DGP	(2,231,965)	(1,451,081)	(4,120,136)	(1,308,256)	(1,067,674)	-	(2,035,822)	(169,652)
TRNP	DGU	(2,425,425)	(4,049,253)	(5,021,355)	(4,462,107)	(1,757,285)	-	(3,543,085)	(295,257)
TRNP	JBG	-	-	-	-	-	-	-	-
TRNP	SG	(9,274,706)	(19,689,386)	(21,221,243)	(20,533,501)	(10,764,740)	1,302,096	(16,036,296)	(1,336,358)
TRNP	NUTIL	-	-	-	-	-	-	-	-
		(13,932,096)	(25,189,720)	(30,362,734)	(26,303,864)	(13,589,699)	1,302,096	(21,615,203)	(1,801,267)
DSTP	CA	(1,186,564)	(1,113,791)	(4,381,160)	(5,331,326)	(5,609,865)	131,307	(3,498,280)	(291,523)
DSTP	ID	(1,813,227)	(4,057,391)	(15,975,382)	(3,422,693)	(1,796,353)	-	(5,413,009)	(451,084)
DSTP	MT	-	-	-	-	-	-	-	-
DSTP	OR	(12,101,471)	(12,071,494)	(14,340,164)	(13,607,490)	(14,022,728)	486,047	(13,131,460)	(1,094,288)
DSTP	UT	(18,052,141)	(27,561,114)	(40,098,584)	(38,143,255)	(31,642,917)	-	(31,099,602)	(2,591,633)
DSTP	WA	(2,535,929)	(1,848,462)	(3,269,263)	(3,781,044)	(2,308,483)	-	(2,748,636)	(229,053)
DSTP	WYP	(3,192,347)	(3,261,905)	(4,136,731)	(3,535,647)	(2,578,048)	-	(3,340,936)	(278,411)
DSTP	WYU	(430,096)	(590,090)	(1,093,567)	(647,723)	(445,821)	-	(641,459)	(53,455)
DSTP	NUTIL	-	-	-	-	-	-	-	-
		(39,311,775)	(50,504,246)	(83,294,850)	(68,469,177)	(58,404,214)	617,353	(59,873,382)	(4,989,448)
GNLP	SE	(467,235)	(29,091)	(5,428)	(119,491)	(163,122)	-	(156,873)	(13,073)
GNLP	SSGCT	-	-	(4,039)	-	(15,838)	-	(3,975)	(331)
GNLP	SG	(10,925,287)	(12,711,663)	(4,050,765)	(11,548,527)	(5,925,301)	-	(9,032,309)	(752,692)
GNLP	DGP	(168,438)	(301,777)	(12,331)	(3,780)	(33,680)	-	(104,001)	(8,667)
GNLP	DGU	(1,244,766)	(37,080)	(154,153)	(139,259)	(67,447)	-	(328,541)	(27,378)
GNLP	SO	(13,374,457)	(17,864,045)	(13,217,260)	(25,898,510)	(6,035,748)	-	(15,278,004)	(1,273,167)
GNLP	CN	(797,489)	(957,283)	(1,113,459)	(702,508)	(1,085,404)	-	(931,228)	(77,602)
GNLP	CA	(981,422)	(931,410)	(156,213)	(718,508)	(228,948)	-	(603,300)	(50,275)
GNLP	ID	(429,609)	(612,386)	(1,204,151)	(2,406,178)	(607,662)	-	(1,051,997)	(87,666)
GNLP	SSGCH			-	-	-	-	-	-
GNLP	OR	(1,961,890)	(21,521,367)	(2,751,204)	(9,268,973)	(7,041,722)	-	(8,509,031)	(709,086)
GNLP	UT	(8,951,496)	(2,688,767)	(2,359,946)	(8,347,713)	(9,497,115)	-	(6,369,007)	(530,751)
GNLP	WA	(604,195)	(1,358,617)	(720,233)	(640,271)	(2,727,188)	-	(1,210,101)	(100,842)
GNLP	WYU	(235,183)	(223,670)	(160,934)	(360,474)	(73,512)	-	(210,754)	(17,563)
GNLP	WYP	(1,527,523)	(1,512,481)	(1,916,806)	(1,724,198)	(1,161,139)	-	(1,568,430)	(130,702)
GNLP	NUTIL	-	-	-	-	-	-	-	-
		(41,668,990)	(60,749,636)	(27,826,920)	(61,878,389)	(34,663,825)	-	(45,357,552)	(3,779,796)
MNGP	SE	-	-	-	-	-	-	-	-
MNGP	NUTIL	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
INTP	JBG	-	-	-	-	-	-	-	-
INTP	SG-P	-	-	(74,111,750)	-	-	74,111,750	-	-
INTP	SG-U	(895,226)	-	-	-	-	-	(179,045)	(14,920)
INTP	SG	(1,268,060)	(103,096)	(115,548)	(11,278,847)	(6,235,212)	58,061	(3,788,541)	(315,712)
INTP	SO	(6,745,772)	(9,053,968)	(9,276,593)	(7,726,853)	(7,828,787)	-	(8,126,395)	(677,200)
INTP	CN	-	(8,201,332)	-	-	(1,085,256)	-	(1,857,318)	(154,776)
INTP	SE	-	-	-	-	-	-	-	-
INTP	DGU	-	(123,397)	-	-	-	-	(24,679)	(2,057)
INTP	CA	-	-	(580)	(8,246)	-	-	(1,765)	(147)
INTP	ID	-	-	(1,727)	(12,827)	-	-	(2,911)	(243)
INTP	OR	-	-	(2,351)	-	(11,172)	-	(2,705)	(225)
INTP	UT	(5,507)	(12,582)	32,081,215	(6,138)	-	(32,081,215)	(4,845)	(404)
INTP	WA	-	-	-	(15,118)	-	-	(3,024)	(252)
INTP	WYU	-	-	-	-	-	-	-	-
INTP	WYP	-	-	(157,662)	(242,917)	-	-	(80,116)	(6,676)
		(8,914,565)	(17,494,375)	(51,584,995)	(19,290,947)	(15,160,428)	42,088,596	(14,071,343)	(1,172,612)
		(609,020,203)	(288,983,079)	(386,566,984)	(263,881,376)	(255,335,365)	683,913,016	(223,974,798)	(18,664,567)

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Descriptions Of Projects Greater Than $10 Million

STEAM PLANT ADDITIONS:

None

HYDRO PLANT ADDITIONS:

IRO P3 South Fork Woodstave Flowline Rep (In-Service Date-Dec 2026), (Reference page 8.5.38)
The Prospect No. 3 Hydroelectric Project has a capacity of 7.2 MW and provides 66,000 MWh annually. This project is required by Paragraph 22 of the Prospect No. 3 Hydroelectric license issued on September 27, 2019. The work includes all design, permitting, and construction associated with the removal of the existing woodstave flowline and installation of a new flowline. The existing wood stave flowline was constructed in 1931, and is prone to significant leakage which has caused surface erosion of the soils along the flowline alignment and has surpassed its original design life. This project involves the analysis, design, permitting and construction of a replacement flowline.

Swift 1 Spillway Gate Retrofit, (In-Service Date-Dec 2026), (Reference page 8.5.38
This project is to ensure the proper and safe function of the spillway gates at Swift 1 Dam. Flood flows are regulated at the Swift 1 dam by two 50-foot wide by 51-foot-tall gates. Inspection and structural analysis indicate that the gates require substantial improvement to meet current seismic criteria. A concurrent study of the gate hoist platforms and machinery that lift the gates indicated that its replacement is required to facilitate opening the gates an additional 4 feet to accommodate the Probable Maximum Flood flows as well as providing a redundant alternative lifting device as identified in the 2017 Consultant's Safety Inspection Report. The work includes all design, permitting, and construction associated with the retrofit of the Swift 1 Dam spillway gates and is necessary to maintain compliance with FERC requirements.

ILR 11.2.2.12 Beaver Bay Park Redesign p, (Service Date-Jan 2026), (Reference page 8.5.38)
The Beaver Bay Campground is an existing campground located near Cougar, WA in Cowlitz County and is part of the Yale Hydroelectric Project. The campground project site encompasses approximately 278 acres and currently offers individual campsites distributed in two separate areas – A and B loops and group camping. In addition to camping, the campground offers a day use area with a gravel parking area, boat launch, picnic area, and swimming area.

This project is required by the 2008 Lewis River Settlement Agreement Section 11.2.2.12, Recreational Facilities Master Plan, Yale Hydroelectric FERC Project License Article 405, the Recreation Resource Management Plan, and FERC's August 26, 2021, Order Amending Recreation Resource Management Plan Pursuant to Article 405 of the Yale Hydroelectric Project license. This project will renovate the Beaver Bay Campground and includes wetland improvements, realignment of the access roads, rearrangement of the campsites, and renovations to comply with the Americans with Disabilities Act (ADA) and its implementing accessibility guidelines (ADAAG). The renovations will develop ADA accessible campsites, new ADA compliant comfort stations, ADA upgrades to the day use area, and other ADA accessible improvements throughout the site.

Toketee 2 Turbine Refurbishment, (In-Service Date-Feb 2026), (Reference page 8.5.38)
Toketee 2 is one of three units of the Toketee development. The three units are identical and have a capacity of 14.167 MW, for a plant capacity of 42.5 MW. Toketee operates as a run of the river plant and has a relatively high-capacity factor of 59%. During the winter and into spring runoff, there is generally sufficient water to operate all three units. Units 1 and 3 are of the same vintage as unit 2, and have been in service for 74 years and have components with significant wear. The risk of load restrictions being implemented on units 1 and 3 is high. There is also significant risk of forced outages. The additional funds

requested are needed to restore unit 2 to service to ensure production from the Toketee plant.

After seventy years of service, refurbishment of Toketee unit 2 was initiated to extend the service life of the unit by addressing wear and deterioration of turbine and generator components. The runner blades had significant cavitation damage. The worn condition of the turbine was also seen in excessive seal clearances which reduced unit efficiency by allowing leakage past the runner directly to the draft tube below the runner or into the head cover above it. The wicket gates were also worn, showing severe pitting, incomplete closure, and poor alignment due to worn bushings. The unit was also subject to a load restriction of 7 MW due to a problem of excessive discharge from the turbine pit drainage system that could not be addressed without disassembling the turbine generator.

This refurbishment project includes installation of a new runner, wicket gates and related components of the turbine assembly. The new runner will incorporate modern design features that are anticipated to increase the efficiency and the horsepower of the turbine. The project also includes refurbishing the generator by rewinding the generator stator with an available set of spare coils and replacing the stator core iron.

Refurbishing Toketee unit 2 will return the unit to service at full capacity and with its efficiency improved by up to 14.5%. It will also reduce the risk of a forced outage that could result in substantial generation losses of up to 43,600 MWh.

IRP P3 Sag Pipe Replacement (In-Service Date-Dec 2026), (Reference page 8.5.38)
The Prospect No. 3 Hydroelectric Project has a capacity of 7.2 MW and provides 66,000 MWh annually. A new FERC license was issued for Prospect No. 3 Hydroelectric Project on September 27, 2019. Paragraph 22 of the license requires replacement of the existing wood stave sag pipe.

The sag pipe was constructed in 1931 and supports operation of both Prospect 3 and Prospect 1, 2, & 4 Hydroelectric projects by conveying water from the tailrace of Prospect 3 to the Middlefork Canal which serves as inflow to the Prospect 1,2,& 4 project. The sag pipe is prone to significant leakage which has caused surface erosion of the soils along the sag pipe alignment and has surpassed its original design life. The sag pipe is located on PacifiCorp property and was removed from service in April 2022 due to failure of the upstream flowline. This project involves the analysis, design, permitting, and construction of a replacement sag pipe.

SOLAR PLANT ADDITIONS:

None

WIND PLANT ADDITIONS:

None

RENEWABLE PLANT ADDITIONS:

None

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Pro Forma Plant Additions
Descriptions Of Projects Greater Than $10 Million

OTHER PLANT ADDITIONS:

Currant Creek U1 CT Rotor Replacement CY25-26 (In-Service Date-Dec 2026), (Reference page 8.5.42)
Purchase and installation of a new Combustion Turbine Rotor on Unit 1, pursuant to the Contractual Service Agreement (CSA) between PacifiCorp and General Electric. PacifiCorp contracts with GE exclusively for repair, replacement, or upgrade work on any components covered under the CSA, which includes the combustion turbine rotors. Currant Creek operates GE Frame 7FA combustion turbines. The turbines include rotors with a designed life expectancy of 144,000 operating hours or 5,000 starts per unit, whichever occurs first. The Current Creek Combustion Turbine Rotors will reach the designed life expectancy hours at the time of installation.

Currant Creek U2 CT Rotor Replacement CY25-26 (In-Service Date-Dec 2026), (Reference page 8.5.42)
Purchase and installation of a new Combustion Turbine Rotor on Unit 2, pursuant to the Contractual Service Agreement (CSA) between PacifiCorp and General Electric. PacifiCorp contracts with GE exclusively for repair, replacement, or upgrade work on any components covered under the CSA, which includes the combustion turbine rotors. Currant Creek operates GE Frame 7FA combustion turbines. The turbines include rotors with a designed life expectancy of 144,000 operating hours or 5,000 starts per unit, whichever occurs first. The Current Creek Combustion Turbine Rotors will reach the designed life expectancy hours at the time of installation.

Current Creek U1 CSA Variable fee 32k – CTA HGP - CY26 (In-Service Date-Apr 2026), (Reference page 8.5.42)
This project is to perform the Hot Gas Path Overhaul on Combustion Turbine Unit 1A, pursuant of the Contractual Service Agreement (CSA) between PacifiCorp and General Electric International, Inc. (GE). Performing the necessary overhaul will result in the unit being able to operate an additional 32,000 hours or 1,200 starts before the next scheduled outage. The Hot Gas Path Overhaul includes the removal and replacement of combustion program parts as outlined in the CSA.

Current Creek U2 CSA Variable fee 32k – CTA HGP - CY26 (In-Service Date-Apr 2026), (Reference page 8.5.42)
This project is to perform the Hot Gas Path Overhaul on Combustion Turbine Unit 2A, pursuant of the Contractual Service Agreement (CSA) between PacifiCorp and General Electric International, Inc. (GE). Performing the necessary overhaul will result in the unit being able to operate an additional 32,000 hours or 1,200 starts before the next scheduled outage. The Hot Gas Path Overhaul includes the removal and replacement of combustion program parts as outlined in the CSA.

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TRANSMISSION PLANT ADDITIONS:

Project Litespeed (In-Service Date-Various), (Reference page 8.5.43)
Project Litespeed is a customer driven major load addition of 242 MW near Boardman, Oregon. There are no suitable facilities at or near the Project Litespeed site to serve the partial or full amount of load requested. PGE's facilities, if upgraded, can serve this load, which is in Pacific Power territory; thus, the most efficient path forward is to enter into a line and load agreement with PGE, construct the initial service plan, and submit a transmission service request with BPA and PGE to meet project deadlines. Redundancy requirements and PacifiCorp transmission service can be met following completion of the final buildout plan.

Project Litespeed (Customer requested ISD – February 2026):

The Boardman area is heavily congested with limited transmission capacity. Multiple service plans were investigated and studied, each carries its own risks, uncertainties, and challenges to meet Customer's timeline. This study supersedes previous studies and proposes the most viable solution with what is perceived to be the quickest timeline.

The initial service plan, which involves interconnection with Portland General Electric (PGE), is presented below, along with a full buildout to provide full N-1 redundancy. These plans are subject to changes based on PGE and Bonneville Power Administration (BPA) requirements and timelines.

Presently, there is a 500 kV line between BPA's Slatt Substation and PGE's Grassland substation. This plan is to negotiate with PGE a new 500 kV position at Grassland and construct a 500-230 kV substation near Grassland. The new 500-230 kV substation will consist of a 1,600 MVA bank of 500-230 kV transformers (three single phase units with a spare fourth unit). The 230 kV yard will be constructed as a breaker-and-a-half configuration and one new 230 kV line would be extended to the customer's site (approximately 8.8 miles north of Grassland). With this option the load request would be initially served out of BPA's Slatt substation and PGE's Grassland substation, creating a double wheel. PacifiCorp has initiated acquiring transmission rights on the Slatt-Grassland 500 kV line with PGE. The line is currently a generation asset and requires FERC filing and approval to convert it to a transmission asset, so heavy negotiation with PGE is required. Note that the existing Dalreed – Carty 230 kV line is limited by BPA's transmission source between Morrow Flats and Jones Canyon. This line does not currently have capacity to serve this load at any level, upgrades necessary to utilize this line have been studied and determined to be prohibitive from a timing perspective.

Detailed transmission upgrades for this initial service plan are as follows:

PGE Grassland:
- Expand the Grassland 500 kV substation to a five-position BAAH bus and add a new line position.
- Construct a 500 kV tie line to PacifiCorp 500-230 kV substation.

PacifiCorp 500-230 kV Substation:
- Construct with one 500 kV (1) bay and two (2) breakers initially with provisions to expand to a future three-bay double bus, double breaker station, with two (2) transformer banks and three (3) 500 kV lines total.
- Install 500-230 kV 4x533.3 MVA single phase transformers (1,600 MVA total capacity, with one spare phase).
- Construct a 230 kV yard (breaker-and-a-half configuration) with one (1) bay and two (2) breakers initially and provision to expand to a future two-bay station with two (2) transformers and four (4) 230 kV lines.

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Descriptions Of Projects Greater Than $10 Million

Transmission:

- Extend one 230 kV transmission line to Customer's site, approximately 8.8 miles north of this site.

Litespeed 230-34.5 kV Yard:

- Construct a 230 kV breaker-and-a-half switching station, with four (4) bays nine (9) breakers initially.
- Install two dual high side 230/115-34.5 kV transformers initially (2 additional 230-34.5 kV ultimately), 115 MVA each.
- Construct 34.5 kV yard with 8 feeders.

Depending on timing, portions of this service plan may need to be constructed in advance to accommodate a separate load request in the area. However, this plan alone will be adequate for radial service up to the full requested amount of Customer load. Additional load capability and/or redundancy will be achieved by constructing the Full Buildout as discussed below.

- Construct a 230 kV breaker-and-a-half switching station, with four (4) bays nine (9) breakers.

Full Buildout Service Plan:

This plan consists of constructing a new 500 kV switching station along the proposed Longhorn – Hemingway 500 kV transmission line, constructing a 16-mile 500 kV tie line between this new station and Grassland Annex, and expanding Grassland annex substation to add a second bank of 1,600 MVA transformers, a new bay, and a new 500 kV line position to connect to the new 500 kV transmission line, bringing another 500 kV source to the area, creating looped 500 kV service (N-1 redundancy), and adding capacity to the newly constructed PacifiCorp 230 kV network. Additionally, construction of a second 8.8-mile 230 kV line between Grassland Annex and Litespeed will be required to provide looped 230 kV service to the Customer.

Detailed transmission upgrades for this full buildout service plan are as follows:

New Substation along the Longhorn – Hemingway 500 kV line:

Construct a new 500 kV switching station along the Longhorn – Hemingway 500 kV transmission line, approximately fifteen miles south of Longhorn substation. Loop in/out the Longhorn and Hemingway lines and add one additional position for a new 16-mile line to the proposed Grassland Annex substation. Construct a new 16-mile 500 kV line between this new station and Grassland Annex substation.

- New switching station along the Longhorn – Hemingway line will be double-bus-double-breaker configuration with three-line positions initially, with provisions for a fourth position.
- Series Cap bank proposed for Longhorn substation will need to be installed at the new switching station instead.
- Transmission line assumed to be constructed using triple bundled 1272 ACSR conductor on standard 500 kV steel poles. Transmission Engineering to make final determination based on cost and schedule.

Grassland Annex Substation:

- Build out the remainder of the initial DBDB bay.
- Add a second DBDB bay and line position (leaving provisions for a third bay and line)
- Install a second bank of 1,600 MVA transformers off the 230 and 500 kV bus.
- Add a second bay and line position to the 230 kV BAAH yard.

Transmission:

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- Construct a second 8.8-mile 230 kV transmission line between Grassland Annex and Litespeed substation, continuing to future Customer planned projects.
- Construct a new 16-mile 500 kV transmission line between the new substation along the Longhorn – Hemingway 500 kV line and Grassland Annex.

Litespeed substation:
- Expand the POI substation to add a 230 kV line position to connect the new 230 kV transmission line between this substation and Grassland Annex.

Depending on timing, portions of this service plan may need to be constructed in advance to accommodate a separate load request in the area. However, this plan alone will be adequate for redundant, looped service up to the full requested amount of Customer load.

The full set of upgrades to the regional transmission system required to serve the requested load in its entirety (242 MW) is dependent upon completion of a separate System Impact Study performed by BPA (Bonneville Power Administration – L0521) who is responsible for operating a much wider main grid network in the Pacific Northwest. In addition, a separate study and agreement with PGE will be required.

Customer 57 - Trans - Q2913 (In-Service Date-Various), (Reference page 8.5.43)
This project completes the new facilities identified through the system impact and facilities study for customer to receive 100 MW of Point-to-Point transmission service on PacifiCorp's transmission system. Work includes rebuilding segments and reconductoring other segments of the Ben Lomond-El Monte 138kV #1 line as well as reconductoring Goshen-Fish Creek-Grace 161kV and Grace-Oneida-Treasureton 138kV lines. Also included are required apparatus and communication upgrades at effective substations.

Gateway South Aeolus Mona 500kV Line (In-Service Date-Dec 2024), (Reference page 8.5.43)
This project built a new 500 kV transmission line from the Aeolus substation, near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The project in conjunction with the Windstar to Shirley Basin 230 kilovolt transmission line (D1) facilitates integration of low-cost resources with delivery to PacifiCorp customers and potential market loads, improves reliability of the transmission system by providing redundant capacity between Gateway West and Gateway Central, and relieves transmission congestion on the existing Wyoming transmission system. The Aeolus – Mona 500 kV line allows transfers of up to 1,700 MW from eastern Wyoming to central Utah.

EDAM (Energy Day Ahead Market System) (In-Service Date-Aug 2026), (Reference page 8.5.43)
PacifiCorp committed to joining the Extended Day-Ahead Market (EDAM) in May 2026, which is incremental to the Western Energy Imbalance Market in which the company has been a participant since 2014. On April 19, 2024, the EDAM project leadership presented the EDAM project plan including capital and OMAG budget through go-live which was approved by the PacifiCorp CEO. On April 25, 2024, PacifiCorp executed the implementation agreement with the California Independent Systems Operator (CAISO) to support this project.

PacifiCorp's vast service territory and regional interconnectedness creates a level of unique complexity. The company must interface with and collate data from numerous transmission customers, third-party LSEs and generator owners, neighboring BAAs, as well as the company's internal data for owned and contracted resources and load. Moreover, the company's market activities require interfacing with the California Independent System Operator (CAISO), with increasing sophistication as the company moves toward participation in the EDAM.

This investment appraisal document outlines the request for $70.5 to implement the EDAM program which is comprised of major enhancements to the existing third-party systems that support WEIM today, enhancement or replacement of existing in-house developed and outdated applications, modernization of

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various forecasting systems, metering upgrades and sundry integration work precipitated by the above change. The type of funding being requested is full funding.

Customer 7 (In-Service Date-Various), (Reference page 8.5.43)

No project definition – confidential.

Project Specialized (In-Service Date-Various), (Reference page 8.5.43)
Project Specialized is a customer driven major load addition of 242 MW near Hermiston, Oregon. System impact studies performed by Transmission Planning have determined that there are no suitable Company-owned facilities at or near the project site that could serve this load. The following service plans were developed to allow for these loads to be served in the most expedient manner possible:

Project Specialized (Customer requested ISD – June 2024):

- Umatilla Electric Co-op (UEC) has indicated that their nearby 115 kV facilities have adequate capacity for this load if converted to 230 kV, and their near-term plans call for construction of a 230 kV switchyard near this site.
- Company will execute a line and load interconnection request with UEC system for necessary upgrades and redundant service from the planned UEC switchyard.
- Company will construct two (2) transmission lines, 1.5 miles each, from the UEC switchyard to a new substation near Project Specialized.
- Company will construct a new 230-34.5 kV substation near the Project Specialized substation to serve this load.
- Preliminary cost estimate: $146.5m, including UEC's work to construct a new 230 kV switchyard and convert a portion of their 115 kV system to 230 kV.

Camp Williams 345-138 kV Transformer and 138 kV Yard Additions (In-Service Date-Dec 2025), (Reference page 8.5.43)
This project replaces the existing 345-138 kV 167 MVA transformer at Camp Williams substation (located in Bluffdale, Utah) with a new 345-138 kV 700 MVA transformer. This will increase capacity by 345 kV. The project also builds a new 138 kV breaker-and-a-half substation, ties two nearby 138 kV lines together within the new 138 kV substation and moves the Camp Williams – 90th South #2 line to a new 345 kV line position. The substation additions and modifications provide a new 345 kV source to one of the 138 kV lines sourcing Oquirrh substation in the event the Oquirrh 345-138 kV transformer is out of service. The new 345 kV source will also support Utah Valley.

St Johns (BPA) to Knott 115kV Line Conversion Project (In-Service Date-Various), (Reference page 8.5.43)
This project in Portland, Oregon converts the St. Johns Switching Station to a 4-breaker ring-bus, reconfigures and converts the existing St. Johns – Columbia (acquired from PGE in 2023), the Columbia – Knott 57 kV lines, and a portion of the idle 69 kV line north of Albina (former 69 kV Sundial Line) to 115 k and adds a tap to provide a third transmission source to Albina substation. The project eliminates a North American Electric Reliability Corporation (NERC) Reliability Standard TPL-001-4 Category P6 (N-1-1) deficiency, resolves the 57 kV system under voltage issues in the North Portland area, and creates a three-way source into Albina, improving reliability for Albina and Knott substations significantly.

Aeolus Sub Transformer Event Resolution (In-Service Date-Aug 2025), (Reference page 8.5.43)
This project repaired and replaced damaged equipment at Aeolus substation due to a fire at the substation on September 29, 2021, that led to the total loss of the 500/230 kilovolt A-Phase transformer unit. The substation was placed in a temporary operating configuration and required reconstruction of damaged facilities, including: 1) replacement of A-Phase transformer; 2) replacement of damaged foundations, structural steel, potential transformers, overhead bus, cables, conduits and trench; 3) removal of the

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temporary 230 kilovolt connection and reconstruction of the 230 kilovolt bus-work; 4) replacement of the damaged tertiary bus and destroyed circuit switcher, air breaks and air core reactors; 5) reconfiguration of the transformers to return the currently utilized spare to a fulltime spare

Malin - Bonanza New 69 kV Line (In-Service Date-Various), (Reference page 8.5.43)
This project builds a new 69 kV transmission line from Malin substation to Bonanza substation in Klamath Falls, Oregon. In addition, the project includes rebuilding existing 69 kV Line 9 between Bonanza substation and Bonanza Tap to reinforce Line 9 with a new source from Malin substation. Completion of the project will mitigate 69 kV system deficiencies associated with five, line-section outages, provide alternate transmission source to six substations, improve load transfer capability between Klamath Falls and Malin substations, and provide initial 230-69 kV capacity relief to Klamath Falls substation.

Pomona Heights 230-115 kV Transformers Replacement TPL (In-Service Date-Various), (Reference page 8.5.43)
The project installs two 280 MVA transformers with Load Tap Changers (LTC) to replace the existing 230-115 kV 150 MVA transformers at Pomona Heights substation, located in Yakima County, Washington. The project will resolve NERC Standard TPL-001-4 Category P1 and P2 events that could result in the loss of either one of the 230-115 kV transformers, causing the thermal overload of the remaining transformer.

Scoville Sub Relocate (In-Service Date-May 2026), (Reference page 8.5.43)
This project will relocate 69 kV facilities from Scoville Substation to nearby Antelope Substation and remove Rocky Mountain Power's equipment from Scoville Substation. Idaho National Laboratory has exercised its contractual right to require removal of Scoville Substation from its campus near Arco, Idaho, with a deadline of May 2026. This relocation is necessary to maintain service to approximately 20 MW of load (~1,000 customers) currently served by Scoville Substation and to eliminate joint-ownership complexities with Idaho Power Company. The project will ensure continued reliability and compliance with land use agreements.

- Land use agreement clause exercised by Idaho National Laboratory requiring removal of Scoville Substation by May 2026
- Approximately 20 MW of load (~1,000 customers) currently served by Scoville Substation must be maintained
- Failure to relocate facilities risks service interruption and potential Commission complaints or intervention
- Delay in removal impacts Idaho National Laboratory's ability to deliver a nuclear research facility to the United States Navy on schedule

Unless this project is completed on time, Rocky Mountain Power faces regulatory risk, customer reliability issues, and contractual non-compliance.

Customer 65 - Trans - Q0787 (In-Service Date-Sep 2025), (Reference page 8.5.43
The customer proposed interconnecting 400 MW of new solar and battery generation to PacifiCorp's Emery-Sigurd #2 345 kV transmission line located in Emery County, Utah.

Loop 90 South - Terminal into MidValley 345 line (In-Service Date-Feb 2026), (Reference page 8.5.43)
This project loops the 90th South – Terminal 345 kV line into and out of the Midvalley 345 kV yard located in Salt Lake City, Utah. This project will increase reliability at Midvalley substation and eliminate the overloading on the 90th South to Midvalley 345 #1 line. The project will also increase transfer capability by 45 MW on the Wasatch Front South transfer path.

Customer 60 - Trans - Q634 (In-Service Date-Oct 2026), (Reference page 8.5.43)
The customer proposed interconnecting 99 megawatts of new solar and battery generation to PacifiCorp's Parowan-Sigurd 230 kV line located in Iron County, Utah.

Customer 81 - Trans - OTP Q0258 (In-Service Date-Feb 2027), (Reference page 8.5.43)
This project consists of expansion of the customer switchyard and construction of a new third bay, and

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installing two breakers and associated equipment to facilitate interconnection of the customer proposed 230 kV transmission line.

GWS Supporting Projects (In-Service Date-Various), (Reference page 8.5.43)
This project installed one 41.6 MVAr shunt capacitor bank at Riverton substation and two 30 MVAr shunt capacitor banks at Mustang substation, both located in Wyoming. With the addition of the Gateway South project, addition of these shunt capacitors supports the additional power that flows through the Riverton – Wyopo 230 kV line and Mustang – Bridger 230 kV line under outage conditions and alleviates low voltage issues while maintaining the reliability and flows through that area.

Windstar–Shirley Basin D1 230kV Trans Ln (In-Service Date-Dec 2024), (Reference page 8.5.43)
This project rebuilt 58 miles of an existing 230 kilovolt transmission line from the Windstar substation near Glenrock east of Casper, Wyoming, to the existing Amasa substation to a new, Heward substation, adjacent to Tri-State's Difficulty substation to the Shirley Basin substation near Medicine Bow, in central Wyoming. The project also included construction of a new 230 kilovolt line of approximately 57 miles from the Windstar substation, east of Casper, Wyoming to Shirley Basin substation, northeast of Medicine Bow, Wyoming in central Wyoming. Additions were also made to existing substations at Shirley Basin, Dave Johnson and Windstar substations and minor modifications at the Amasa substation. The addition of this project, in conjunction with Gateway South (Aeolus – Mona 500 kV Line) allows interconnection of low cost resources in eastern Wyoming. It increases transfer capability by approximately 750 MW from the Windstar/Dave Johnston area south to Shirley Basin/Aeolus in turn supports approximately 1,700 megawatts of transfer capability from eastern Wyoming (Aeolus) to the central Utah energy hub (Mona/Clover).

Hurricane Sub: New Spare 230-69 kV, 25 MVA Trans (In-Service Date-Dec 2026), (Reference page 8.5.43)
Purchase of a new transformer to parallel with existing transformer. Includes the replacement of obsolete Power Line Carrier and relaying.

FERC Order 881 Mandate Upgrades (In-Service Date-Dec 2026), (Reference page 8.5.43)
This project implements the upgrades and engineering necessary to make PacifiCorp compliant with Federal Energy Regulatory Commission (FERC) Order 881 which requires improvement in the accuracy and transparency of transmission line ratings.

Oquirrh Terminal 345kV Line (In-Service Date-Oct 2025), (Reference page 8.5.43)
This project constructed a new double circuit transmission line between Oquirrh substation, in West Jordan Utah, north to the Terminal substation, located south of the Salt Lake City international airport. This section

of new transmission links together the already completed Mona to Oquirrh and Populus to Terminal transmission line to complete the Gateway Central portion of the Energy Gateway Transmission Expansion. This project mitigates transmission constraint between the Mona area and Wasatch front, increases path transfer capacity by 511 MW and meets long term capacity needs for Salt Lake County. The project allows for more solar generation to move north while serving the load in the Wasatch front.

Walla Walla 69kV Loop Reconfigure and Reconductor (In-Service Date-Various), (Reference page 8.5.43)
This project reconductors 8.5 miles and rebuilds 3.2 miles of 69 kV line to ensure adequate N-1 contingency coverage for outages in the 69 kV core area of Walla Walla. The reconfiguration of the Yellow Hawk and Pine Creek lines removes a large portion of aged 1/0 Copper from service and provides an express path to Walla Walla for the connected generation at Combine Hills.

Dixonville Sub Replace Transformer T-3112 (In-Service Date-Nov 2025), (Reference page 8.5.43)
This project replaces the existing 230-115 kV transformer (T-3112) at Dixonville substation in Roseburg, Oregon with a new 280 MVA transformer. The replacement of this transformer would allow an acceptable

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level of regulation during high main grid voltage conditions. In addition, current load projects show the need for an additional 115 kV capacity for Dixonville substation by 2028, so the installation of a 280 kV transformer both partially addresses this capacity issue and allows for the upgrading of the current 125 kV transformer later as load growth materializes.

DISTRIBUTION PLANT ADDITIONS:

Portland Willamette River Crossing (In-Service Date-Feb 2026), (Reference page 8.5.45)
A project to replace the existing distribution cables crossing the Willamette River from the Albina substation to downtown Portland. Includes 12 new distribution feeders with a capacity of 35 mega-watts (MW) in a single bore to serve the existing 2,000 customers on the Albina network with sufficient redundancy and accommodate load growth on the network.

Yew Ave Capacity Increase (In-Service Date-Various), (Reference page 8.5.45
This project installs a second 25 MVA, 116-12.5 kV LTC transformer at Yew Ave substation. A second metal-clad switchgear is included with four new feeder positions (2-3 installed initially) and associated distribution feeder reconfiguration. The project will provide load relief for the existing Yew Avenue feeders and transformer.

Bond Street Add 2nd Transformer (In-Service Date-Various), (Reference page 8.5.45)
This project installs a second 25 MVA, 69-12.5 kV LTC transformer, second switchgear, and fourth and fifth feeder at Bond Street substation in Bend, Oregon. The project will prevent overloading at Bond Street substation and to some extent Cleveland Ave and China Hat substations. The fourth and fifth feeder at Bond Street substation adds feeder capacity and allows for better transferability, reliability and ability to serve loads in the immediate vicinity.

Dixonville T-3843 replacement (In-Service Date-Sep 2026), (Reference page 8.5.45)
Customer load request increase for hydro facilities, includes a transformer replacement to accommodate the load growth.

GENERAL and INTANGIBLE PLANT ADDITIONS:

Willamette Ops Center (In-Service Date-Various), (Reference page 8.5.48)
Pursue the purchase of property for the eventual construction of a new Willamette Operations Center.

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Regulatory Assets & Liabilities Amortization

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Elec. Plant Acq. Acc. Amort.	115	3	(75,351)	SG	27.756%	(20,914)	8.6.1

Description of Adjustment:

This adjustment walks forward Electric Plant Acquisition in the base period (12 months ended June 2025) to pro forma period levels (12 months ending December 2027).

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Regulatory Assets & Liabilities Amortization
Electric Plant Acquisition Adjustment

Adjust Base Period to Pro Forma Period

		Rate Base	
	Amortization	**Gross Acq.**	**Acc Amort**
Pro Forma Amount (below)	75,351	144,704,699	(142,277,231)
Base Period Amount (below)	75,351	144,704,699	(142,201,879)
Pro Forma Adjustment	**-**	**-**	**(75,351)**
	Ref. 8.6	**Ref. 8.6**	**Ref. 8.6**

Year		**Gross Acquisition**	**Beg Balance Accumulated Amortization**	**Amortization**	**End Balance Accumulated Amortization**	**13 Month Avg Bal Gross Acq**	**13 Month Avg Bal Acc Amort**
	Opening Balance	144,704,699			(142,164,204)		
2024	July	144,704,699	(142,164,204)	(6,279)	(142,170,483)		
	August	144,704,699	(142,170,483)	(6,279)	(142,176,762)		
	September	144,704,699	(142,176,762)	(6,279)	(142,183,042)		
	October	144,704,699	(142,183,042)	(6,279)	(142,189,321)		
	November	144,704,699	(142,189,321)	(6,279)	(142,195,600)		
	December	144,704,699	(142,195,600)	(6,279)	(142,201,879)		
2025	January	144,704,699	(142,201,879)	(6,279)	(142,208,159)		
	February	144,704,699	(142,208,159)	(6,279)	(142,214,438)		
	March	144,704,699	(142,214,438)	(6,279)	(142,220,717)		
	April	144,704,699	(142,220,717)	(6,279)	(142,226,997)		
	May	144,704,699	(142,226,997)	(6,279)	(142,233,276)		
	June	144,704,699	(142,233,276)	(6,279)	(142,239,555)	144,704,699	(142,201,879)
			Base Period Amort =	(75,351)			
2025	July	144,704,699	(142,239,555)	(6,279)	(142,245,834)		
	August	144,704,699	(142,245,834)	(6,279)	(142,252,114)		
	September	144,704,699	(142,252,114)	(6,279)	(142,258,393)		
	October	144,704,699	(142,258,393)	(6,279)	(142,264,672)		
	November	144,704,699	(142,264,672)	(6,279)	(142,270,951)		
	December	144,704,699	(142,270,951)	(6,279)	(142,277,231)		
2026	January	144,704,699	(142,277,231)	(6,279)	(142,283,510)		
	February	144,704,699	(142,283,510)	(6,279)	(142,289,789)		
	March	144,704,699	(142,289,789)	(6,279)	(142,296,069)		
	April	144,704,699	(142,296,069)	(6,279)	(142,302,348)		
	May	144,704,699	(142,302,348)	(6,279)	(142,308,627)		
	June	144,704,699	(142,308,627)	(6,279)	(142,314,906)	144,704,699	(142,277,231)
	July	144,704,699	(142,314,906)	(6,279)	(142,321,186)		
	August	144,704,699	(142,321,186)	(6,279)	(142,327,465)		
	September	144,704,699	(142,327,465)	(6,279)	(142,333,744)		
	October	144,704,699	(142,333,744)	(6,279)	(142,340,024)		
	November	144,704,699	(142,340,024)	(6,279)	(142,346,303)		
	December	144,704,699	(142,346,303)	(6,279)	(142,352,582)		
2027	January	144,704,699	(142,352,582)	(6,279)	(142,358,861)		
	February	144,704,699	(142,358,861)	(6,279)	(142,365,141)		
	March	144,704,699	(142,365,141)	(6,279)	(142,371,420)		
	April	144,704,699	(142,371,420)	(6,279)	(142,377,699)		
	May	144,704,699	(142,377,699)	(6,279)	(142,383,979)		
	June	144,704,699	(142,383,979)	(6,279)	(142,390,258)		
	July	144,704,699	(142,390,258)	(6,279)	(142,396,537)		
	August	144,704,699	(142,396,537)	(6,279)	(142,402,816)		
	September	144,704,699	(142,402,816)	(6,279)	(142,409,096)		
	October	144,704,699	(142,409,096)	(6,279)	(142,415,375)		
	November	144,704,699	(142,415,375)	(6,279)	(142,421,654)		
	December	144,704,699	(142,421,654)	(6,279)	(142,427,933)	144,704,699	(142,390,258)
			Pro Forma Amort =	(75,351)			

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Regulatory Assets & Liabilities Amortization
Electric Plant Acquisition Adjustment
GL Account 140800 - Actuals for 12 Months Ended June 2025

Year	Month	Addition / Amortization	Accumulated Amount
2024	6	-	156,468,483
2024	7	-	156,468,483
2024	8	-	156,468,483
2024	9	-	156,468,483
2024	10	-	156,468,483
2024	11	-	156,468,483
2024	12	-	156,468,483
2025	1	-	156,468,483
2025	2	-	156,468,483
2025	3	-	156,468,483
2025	4	-	156,468,483
2025	5	-	156,468,483
2025	6	-	**156,468,483**

System-allocated amount	144,704,699	**Ref Tab B-15 & 8.6.1**
Utah-situs amount	11,763,784	**Ref Tab B-15**
	156,468,483	

GL Account Balance
Account Number 140800

Calendar year 2024

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				156,468,482.73
1				156,468,482.73
2				156,468,482.73
3				156,468,482.73
4				156,468,482.73
5				156,468,482.73
6				156,468,482.73
7				156,468,482.73
8				156,468,482.73
9				156,468,482.73
10				156,468,482.73
11				156,468,482.73
12				156,468,482.73

Calendar year 2025

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				156,468,482.73
1				156,468,482.73
2				156,468,482.73
3				156,468,482.73
4				156,468,482.73
5				156,468,482.73
6				156,468,482.73
7				156,468,482.73
8				156,468,482.73
9				156,468,482.73
10				156,468,482.73
11				156,468,482.73
12				156,468,482.73

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Regulatory Assets & Liabilities Amortization
Accumulated Amortization
GL Account 145800 - Actuals for 12 Months Ended June 2025

Year	Month	Amort.	Accumulated Amount
2024	6		(144,891,300)
2024	7	(31,416)	(144,922,716)
2024	8	(31,416)	(144,954,131)
2024	9	(31,416)	(144,985,547)
2024	10	(31,416)	(145,016,962)
2024	11	(31,416)	(145,048,378)
2024	12	(31,416)	(145,079,794)
2025	1	(31,416)	(145,111,209)
2025	2	(31,416)	(145,142,625)
2025	3	(31,416)	(145,174,040)
2025	4	(31,416)	(145,205,456)
2025	5	(31,416)	(145,236,871)
2025	6	(31,416)	**(145,268,287)**

System-allocated amount	(142,164,204)	**Ref. Tab B-15 & 8.6.1**
Utah-situs amount	(3,104,083)	**Ref. Tab B-15**
	(145,268,287)	

GL Account Balance
Account Number 145800
Calendar year 2024

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				144,702,806.77-
1		31,415.56	31,415.56-	144,734,222.33-
2		31,415.58	31,415.58-	144,765,637.91-
3		31,415.56	31,415.56-	144,797,053.47-
4		31,415.58	31,415.58-	144,828,469.05-
5		31,415.56	31,415.56-	144,859,884.61-
6		31,415.57	31,415.57-	144,891,300.18-
7		31,415.57	31,415.57-	144,922,715.75-
8		31,415.56	31,415.56-	144,954,131.31-
9		31,415.57	31,415.57-	144,985,546.88-
10		31,415.57	31,415.57-	145,016,962.45-
11		31,415.57	31,415.57-	145,048,378.02-
12		31,415.57	31,415.57-	145,079,793.59-

Calendar year 2025

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				145,079,793.59-
1		31,415.56	31,415.56-	145,111,209.15-
2		31,415.58	31,415.58-	145,142,624.73-
3		31,415.56	31,415.56-	145,174,040.29-
4		31,415.58	31,415.58-	145,205,455.87-
5		31,415.56	31,415.56-	145,236,871.43-
6		31,415.57	31,415.57-	145,268,287.00-
7		31,415.57	31,415.57-	145,299,702.57-
8		31,415.56	31,415.56-	145,331,118.13-
9		31,415.57	31,415.57-	145,362,533.70-
10				145,362,533.70-
11				145,362,533.70-
12				145,362,533.70-

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Plant Held for Future Use

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Remove PHFU	105	1	(1,461,372)	SG	27.7556%	(405,612)	
Remove PHFU	105	1	-	CA	0.0000%	-	
Remove PHFU	105	1	(4,562,424)	OR	100.0000%	(4,562,424)	
Remove PHFU	105	1	(5,168,253)	UT	0.0000%	-	
Remove PHFU	105	1	(601)	WYP	0.0000%	-	
			(11,192,650)			(4,968,037)	8.7.1

Description of Adjustment:

This adjustment removes all Plant Held for Future Use (PHFU) assets from FERC account 105. The company is making this adjustment in compliance with UE 116, Order No. 01-787, Appendix A, page 4 of 5 and continues to assess these projects for appropriate inclusion in regulated results.

PacifiCorp
Oregon General Rate Case - December 2027
Plant Held for Future Use

Primary Account		Secondary Account		Alloc	Total
1050000	Plant Held for Future Use	3501000	LAND OWNED IN FEE	SG	706,810
1050000	Plant Held for Future Use	3502000	LAND RIGHTS	SG	754,562
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	CA	-
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	OR	4,562,424
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	UT	5,168,253
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	WYP	601
1050000	Plant Held for Future Use	3891000	LAND OWNED IN FEE	OR	-
Total					**11,192,650**

Ref. 8.7

PacifiCorp PAGE 8.8
Oregon General Rate Case - December 2027
Pension and Other Post-retirement Plan Balances Removal

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Net Prepaid Balance	128	1	(158,341,112)	SO	27.909%	(44,191,249)	8.8.1
Net Prepaid Balance	182M	1	(191,936,652)	SO	27.909%	(53,567,392)	8.8.1
Net Prepaid Balance	182M	1	(4,425,023)	WY	Situs	-	8.8.1
Net Prepaid Balance	2283	1	-	SO	27.909%	-	8.8.1
			(354,702,788)			(97,758,641)	
Adjustment to Tax:							
ADIT Balances	190	1	(12,672,553)	SO	27.909%	(3,536,769)	8.8.1
ADIT Balances	283	1	98,034,507	SO	27.909%	27,360,344	8.8.1
ADIT Balances	283	1	1,087,963	WY	Situs	-	8.8.1
			86,449,916			23,823,575	

Description of Adjustment:

This adjustment removes the Company's net prepaid asset associated with its pension and other postretirement welfare plans, net of associated accumulated deferred income taxes in unadjusted results. Per Order No. 15-226 in Docket UM 1633, the net pension and post retirement prepaid is not to be included in rate base for Oregon.

PacifiCorp Page 8.8.1
Oregon General Rate Case - December 2027
Pension and Other Post-retirement Plan Balances Removal

FERC Pension Account	Factor	Jun-25 End of Period Balances	Ref
128	SO	158,341,112	**8.8**
182M	SO	191,936,652	**8.8**
182M	WY	4,425,023	**8.8**
2283	SO	-	**8.8**
		354,702,788	

FERC Tax Account	Factor	Jun-25 End of Period Balances	Ref
190	SO	12,672,553	**8.8**
283	SO	(98,034,507)	**8.8**
283	WY	(1,087,963)	**8.8**
		(86,449,916)	

PacifiCorp PAGE 8.9
Oregon General Rate Case - December 2027
Capitalized Incentives

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Depreciation Expense:							
Deprec. Exp. Cap. of NEO Incentive	403368	3	(32,888)	OR	Situs	(32,888)	8.9.1
Deprec. Exp. Cap. of Non-NEO Incentive	403368	3	(471,007)	OR	Situs	(471,007)	8.9.1
Adjustment to Rate Base:							
Remove Capitalization of NEO Incentive	1869	3	(928,759)	OR	Situs	(928,759)	8.9.1
Remove Capitalization of Non-NEO Incentive	1869	3	(13,427,507)	OR	Situs	(13,427,507)	8.9.1
Adjustment to Tax:							
Schedule M Adjustment - NEO	SCHMDT	3	(32,888)	OR	Situs	(32,888)	
Deferred Income Tax Expense - NEO	41010	3	(8,086)	OR	Situs	(8,086)	
ADIT Balance - NEO	282	3	228,350	OR	Situs	228,350	
Schedule M Adjustment - Non-NEO	SCHMDT	3	(471,007)	OR	Situs	(471,007)	
Deferred Income Tax Expense - Non-NEO	41010	3	(115,805)	OR	Situs	(115,805)	
ADIT Balance - Non-NEO	282	3	3,301,368	OR	Situs	3,301,368	

Description of Adjustment:

This adjustment includes a reduction to rate base and associated depreciation expense associated with officer and non-officer incentives prepared in a consistent manner with the adjustment adopted in commission order 24-447 in Docket No. UE-433 to remove capitalized incentives back through 2015. However, since 2025 balance is yet unknown, for purposes of this adjustment the company applied a five-year average methodology adopted in docket No.UE-433 to estimate for years for which data was not yet available.

PacifiCorp
Oregon General Rate Case - December 2027
Capitalized Incentives

	Total Company			Oregon Allocated		
Calendar Year	PacifiCorp NEO, Capitalized AIP	PacifiCorp NEO, Capitalized Bonus	Oregon's Allocated share[1]	Cumulative NEO AIP/Bonus	Accumulated Depreciation	Net Balance
2015	300,868	130,105	116,696	116,696	(1,721)	114,974
2016	327,774	26,651	98,194	214,889	(6,612)	208,277
2017	334,414	62,217	107,514	322,404	(14,537)	307,866
2018	349,248	8,483	97,795	420,198	(25,491)	394,708
2019	371,909	-	102,434	522,632	(39,397)	483,235
2020	416,671	14,035	121,213	643,845	(56,603)	587,242
2021	316,452	14,119	92,533	736,379	(76,961)	659,417
2022	369,754	18,377	107,783	844,161	(100,274)	743,887
2023	102,834	143,455	68,867	913,028	(126,193)	786,836
2024	-	377,677	103,110	1,016,138	(154,648)	861,490
2025			98,701	1,114,839	(186,080)	**928,759**
						Ref 8..9

Annual Depreciation Expense **32,888**
Ref 8.9

	Total Company			Oregon Allocated		
Calendar Year	Non-NEO Capitalized AIP	Non-NEO Capitalized Bonus	Oregon's Allocated share[1]	Cumulative Non-NEO AIP/Bonus	Accumulated Depreciation	Net Balance
2015	4,831,779	492,208	1,441,591	1,441,591	(21,263)	1,420,328
2016	4,383,706	691,292	1,406,030	2,847,621	(84,529)	2,763,092
2017	4,161,158	490,044	1,260,795	4,108,416	(187,131)	3,921,285
2018	4,588,631	315,218	1,340,587	5,449,003	(328,103)	5,120,900
2019	4,821,055	650,146	1,506,917	6,955,920	(511,075)	6,444,844
2020	4,897,584	289,530	1,459,806	8,415,725	(737,807)	7,677,918
2021	5,010,448	32,279	1,411,561	9,827,286	(1,006,892)	8,820,395
2022	5,861,184	314,003	1,714,827	11,542,113	(1,322,090)	10,220,023
2023	4,832,548	476,175	1,484,415	13,026,528	(1,684,478)	11,342,051
2024	5,167,934	99,531	1,438,071	14,464,599	(2,089,972)	12,374,628
2025			1,501,736	15,966,335	(2,538,828)	**13,427,507**
						Ref 8.9

Depr Rate[2] 2.95%

Annual Depreciation Expense **471,007**
Ref 8.9

[1] Oregon's allocated share is extrapolated using an unadjusted gross electric plant in-service (EPIS) percentage calculated as: Oregon's gross EPIS balance divided by Total Company gross EPIS balance. Gross EPIS balances are sourced from the Company's annual results of operations (ROO) filings.

[2] The depreciation rate assumed in adjustment proposed by Staff and adopted per Commission Order No. 24-447 in GRC UE-433.

PacifiCorp PAGE 8.10
Oregon General Rate Case - December 2027
Remove Rolling Hills

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Wind Production Plant	338WP	1	(196,439,532)	SG	27.76%	(54,522,921)	8.10.1
Adjustment to Depreciation Reserve:							
Other Plant	108WP	1	14,279,707	SG	27.76%	3,963,415	8.10.1
Adjustment to O&M Expense:							
Administrative & General	929	1	(173,175)	SO	28.25%	(48,927)	8.10.1
Misc. Oth. Power Supply	549	1	(18,836)	SG	27.76%	(5,228)	8.10.1
Misc. Oth. Power Supply	553	1	(741,748)	SG	27.76%	(205,876)	8.10.1
Misc. Wind Power Supply	558WP	1	(834,466)	SG	27.76%	(231,611)	8.10.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMDT	1	(214,182)	TAXDEPR	27.74%	(59,410)	
Deferred Tax Expense	41010	1	(52,660)	TAXDEPR	27.74%	(14,607)	
ADIT Balance	282	1	43,143,479	SG	27.76%	11,974,720	

This adjustment removes the gross plant, accumulated depreciation, depreciation expense and O&M amounts related to the Rolling Hills wind resource from the 12 months ended June 2025. This treatment is consistent Commission Order No. 08-548.

PacifiCorp
Oregon General Rate Case - December 2027
Remove Rolling Hills

Rate Base	FERC Account	Indicator	EOP June 2025	Ref.
Electric Plant In Service				
STRUCTURES AND IMPROVEMENTS - WIND	3382100	338WP	28,228,969	
WIND TURBINES	3382300	338WP	107,592,815	
WIND TURBINES - GENERATORS	3382301	338WP	7,927,686	
WIND TOWERS AND FIXTURES	3382400	338WP	37,856,995	
COLLECTOR SYSTEM - WIND	3382600	338WP	10,099,705	
GSU AND ASSOC EQUIP - WIND	3382700	338WP	2,553,366	
ACCESSORY ELECTRIC EQUIPMENT - WIND	3382900	338WP	1,520,498	
MISC POWER PLANT EQUIP - WIND	3383300	338WP	659,497	
			196,439,532	8.10
Depreciation Reserve				
Other Plant	108	108WP	(14,279,707)	8.10

Expense Amounts	FERC Account	Indicator	12 ME June 2025	Ref.
Operation & Maintenance Expense				
DUPLICATE CHRGS-CR	9290000	929	173,175	8.10
MIS OTH PWR GEN EX	5490000	549	18,836	8.10
MNT GEN & ELEC PLT	5530000	553	741,748	8.10
MAINT MISC WIND GEN	5582300	558WP	834,466	8.10

PacifiCorp PAGE 8.11
Oregon General Rate Case - December 2027
Deer Creek Mine Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove base period expense							
Closure Costs Amortization	506	1	(2,063,172)	SG	27.756%	(572,645)	8.11.1
Add pro forma expense							
Deer Creek Recovery Royalities	506	3	5,261,096	SE	26.823%	1,411,173	8.11.2
Adjustment to Rate Base:							
Remove base period regulatory assets							
Closure Costs Regulatory Asset	182M	1	(59,453)	OR	Situs	(59,453)	8.11.1
Closure Costs Regulatory Asset	182M	1	(76,068,432)	SE	26.823%	(20,403,673)	8.11.1
Closure Costs Regulatory Asset	182M	1	(8,323,073)	SO	27.909%	(2,322,877)	8.11.1
Add proforma period regulatory assets							
Deer Creek Recovery Royalties	182M	3	3,074,652	SE	26.823%	824,707	8.11.2
Adjustment to Tax:							
Remove Base Period Tax							
Schedule M Addition	SCHMAT	1	(348,695)	SE	26.823%	(93,530)	
Schedule M Addition	SCHMAT	1	(86,825)	SO	27.909%	(24,232)	
Schedule M Deduction	SCHMDT	1	121,093	SE	26.823%	32,480	
Schedule M Deduction	SCHMDT	1	-	OR	Situs	-	
Def Income Tax Expense	41110	1	85,732	SE	26.823%	22,996	
Def Income Tax Expense	41110	1	21,347	SO	27.909%	5,958	
Def Income Tax Expense	41010	1	29,773	SE	26.823%	7,986	
Def Income Tax Expense	41010	1	-	OR	Situs	-	
Accum Def Income Tax Balance	283	1	(14,327,978)	SE	26.823%	(3,843,163)	
Accum Def Income Tax Balance	283	1	39,536,806	SE	26.823%	10,604,873	
Accum Def Income Tax Balance	190	1	(19,634,111)	SE	26.823%	(5,266,416)	
Accum Def Income Tax Balance	283	1	-	SO	27.909%	-	
Accum Def Income Tax Balance	283	1	(150,542)	OR	Situs	(150,542)	
Add proforma period Tax							
DC Recovery Royalties - Schedule M	SCHMAT	3	5,261,096	SE	26.823%	1,411,173	
DC Royalties - DIT Expense	41010	3	(1,293,525)	SE	26.823%	(346,959)	
DC Recovery Royalties - ADIT	283	3	(755,952)	SE	26.823%	(202,768)	

Description of Adjustment:

Oregon Order No. 15-161 in Docket UM 1712 approved closure of the Deer Creek mine located in Utah and ruled on several issues. This adjustment removes the Deer Creek Unrecovered Plant Regulatory Assets from results because these amounts are recovered through separate tariff riders in Docket No. UE 374, Order No. 20-473.

Order No. 15-161 authorized to include the $3 million annual payment resulting from the Company's withdrawal from the 1974 Pension Trust associated with the Deer Creek Mine. These pension costs were previously included in the TAM, but were moved from the TAM to base rates per resolution in Docket No. UE-374 and UE-375. This annual payment continues to be included in base rates, but since the last general rate case, this annual payment is recorded on the company's accounting records allocating into Oregon's base period results without an incremental adjustment to bring the balance into the test period. For this reason, there's no longer an adjustment for this cost item reflected as part of this page.

The Company is also including through this adjustment the amortization of coal lease abandonment royalty costs, approved in Docket UE-433, Order No. 24-.447, with rates that took effect 1/1/2025.

PacifiCorp
Oregon General Rate Case - December 2027
Deer Creek Mine Adjustment
Base Period Balances

EXPENSE ACCOUNTS

	Amort	
Amortization in Base Period Results	**2,063,172**	
	Ref. 8.11	

Recovery of Deer Creek closure costs in Oregon is included in a separate tariff rider. Thus, system amounts in unadjusted results should be removed.

RATE BASE ACCOUNTS

	EOP June 2025 Balance	Booked Allocation	
Unrecovered Plant	(1,662,000)	SE	
Unrecovered Plant	752,316	OR	
Closure Costs	77,730,431	SE	
Closure Costs	(692,863)	OR	
UMWA PBOP Savings	-	OR	
UMWA PBOP	8,323,073	SO	
Total	**84,450,957**		

Summary by Allocation Factor

59,453	OR	**Ref. 8.11**
76,068,432	SE	**Ref. 8.11**
8,323,073	SO	**Ref. 8.11**
84,450,957		

Oregon's share of Deer Creek mine unrecovered closure costs (except recovery royalties) are being recovered through a separate tariff rider. All balances are removed from rate base as the balances include carrying charges. For recovery royalties amortization details, please refer to page 8.11.2.

PacifiCorp
Oregon General Rate Case - December 2027
Deer Creek Mine Adjustment
Recovery Royalties - Closure Costs

Recovery Royalties Approved for Amortization in docket UE 433	15,783,288	
Approved Amortization Period	3	Years
Approved Annual Amortization	***5,261,096***	

Date	Beg Bal	Additions	Amortization	End Bal	SCHMAT	41110	190
Jun-25	14,035,269		(438,425)	13,596,844			
Jul-25	13,596,844		(438,425)	13,158,420			
Aug-25	13,158,420		(438,425)	12,719,995			
Sep-25	12,719,995		(438,425)	12,281,570			
Oct-25	12,281,570		(438,425)	11,843,146			
Nov-25	11,843,146		(438,425)	11,404,721			
Dec-25	11,404,721		(438,425)	10,966,296			
Jan-26	10,966,296		(438,425)	10,527,872			
Feb-26	10,527,872		(438,425)	10,089,447			
Mar-26	10,089,447		(438,425)	9,651,022			
Apr-26	9,651,022		(438,425)	9,212,598			
May-26	9,212,598		(438,425)	8,774,173			
Jun-26	8,774,173		(438,425)	8,335,748			
Jul-26	8,335,748		(438,425)	7,897,324			
Aug-26	7,897,324		(438,425)	7,458,899			
Sep-26	7,458,899		(438,425)	7,020,474			
Oct-26	7,020,474		(438,425)	6,582,050			
Nov-26	6,582,050		(438,425)	6,143,625			
Dec-26	6,143,625		(438,425)	5,705,200			(1,402,715)
Jan-27	5,705,200		(438,425)	5,266,775	438,425	(107,794)	(1,294,921)
Feb-27	5,266,775		(438,425)	4,828,351	438,425	(107,794)	(1,187,127)
Mar-27	4,828,351		(438,425)	4,389,926	438,425	(107,794)	(1,079,334)
Apr-27	4,389,926		(438,425)	3,951,501	438,425	(107,794)	(971,540)
May-27	3,951,501		(438,425)	3,513,077	438,425	(107,794)	(863,746)
Jun-27	3,513,077		(438,425)	3,074,652	438,425	(107,794)	(755,952)
Jul-27	3,074,652		(438,425)	2,636,227	438,425	(107,794)	(648,159)
Aug-27	2,636,227		(438,425)	2,197,803	438,425	(107,794)	(540,365)
Sep-27	2,197,803		(438,425)	1,759,378	438,425	(107,794)	(432,571)
Oct-27	1,759,378		(438,425)	1,320,953	438,425	(107,794)	(324,778)
Nov-27	1,320,953		(438,425)	882,529	438,425	(107,794)	(216,984)
Dec-27	882,529		(438,425)	444,104	438,425	(107,794)	(109,190)
Amortization Expense 12 Months Ending Dec-27			**(5,261,096)**		**5,261,096**	**(1,293,525)**	
			Ref 8.11		**Ref 8.11**	**Ref 8.11**	
		13 Month Average Dec-27		**3,074,652**			**(755,952)**
				Ref 8.11			**Ref 8.11**

PacifiCorp PAGE 8.12
Oregon General Rate Case - December 2027
Emissions Control Equipment Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF
Adjustment to Rate Base:							
Hunter Clean Air Disallowance	312	1	(2,290,114)	SG	27.756%	(635,634)	8.12.1
Adjustment to Expense:							
Hunter Clean Air Disallowance	403SP	1	(516,260)	SG	27.756%	(143,291)	8.12.1
Adjustment to Return:							
JB U3 & U4 Return Disallowance	930	1	(2,634,206)	SG	27.756%	(731,139)	8.12.3
JB U3 & U4 Return Disallowance	930	3	1,081,666	SG	27.756%	300,223	8.12.3
			(1,552,540)			(430,916)	
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	1	(516,260)	SG	27.756%	(143,291)	
Schedule M Adjustment	SCHMDT	1	(181,056)	SG	27.756%	(50,253)	
Deferred Income Tax Expense	41110	1	126,931	SG	27.756%	35,230	
Deferred Income Tax Expense	41010	1	(44,516)	SG	27.756%	(12,356)	
Accumulated Def Inc Tax Balance	282	1	251,426	SG	27.756%	69,785	

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.

PacifiCorp
Oregon General Rate Case - December 2027
Emissions Control Equipment Adjustment
Hunter Clean Air Equipment Summary

13-Month Average Balance - December 2027		
EPIS Balance	81,171,892	Ref 8.12.2
Steam Plant Reserve	(58,270,747)	Ref 8.12.2
Net Book Value	22,901,145	
NBV Ordered 10% Disallowance	2,290,114	Ref 8.12

13-Month Average Balance - December 2027		
Gross Plant	81,171,892	Above
Depreciation Rate[1]	6.360%	
Depreciation Expense	5,162,596	
Depr Ordered 10% Disallowance	516,260	Ref 8.12

1. Actual composite steam depreciation rate for June 2025.

PacifiCorp
Oregon General Rate Case - December 2027
Emissions Control Equipment Adjustments
Hunter Clean Air Net Book Value

	Gross Plant	Depreciation Reserve	Depreciation Expense
Jun-24	81,171,892	(42,498,920)	453,886
Jul-24	81,171,892	(42,952,806)	453,886
Aug-24	81,171,892	(43,406,693)	453,886
Sep-24	81,171,892	(43,860,579)	453,886
Oct-24	81,171,892	(44,314,465)	453,886
Nov-24	81,171,892	(44,768,351)	453,886
Dec-24	81,171,892	(45,222,237)	453,886
Jan-25	81,171,892	(45,676,123)	453,886
Feb-25	81,171,892	(46,130,009)	453,886
Mar-25	81,171,892	(46,583,896)	453,886
Apr-25	81,171,892	(47,037,782)	453,886
May-25	81,171,892	(47,491,668)	453,886
Jun-25	81,171,892	(47,945,554)	453,886
Year End	81,171,892	(47,945,554)	453,886

Jun-25 Year End Undepreciated Balance 33,226,337

	Pro Forma Capital Addition	Gross Plant	Depreciation Reserve	Depreciation Expense
Jul-25	-	81,171,892	(48,375,771)	430,216
Aug-25	-	81,171,892	(48,805,987)	430,216
Sep-25	-	81,171,892	(49,236,203)	430,216
Oct-25	-	81,171,892	(49,666,420)	430,216
Nov-25	-	81,171,892	(50,096,636)	430,216
Dec-25	-	81,171,892	(50,526,852)	430,216
Jan-26	-	81,171,892	(50,957,069)	430,216
Feb-26	-	81,171,892	(51,387,285)	430,216
Mar-26	-	81,171,892	(51,817,501)	430,216
Apr-26	-	81,171,892	(52,247,718)	430,216
May-26	-	81,171,892	(52,677,934)	430,216
Jun-26	-	81,171,892	(53,108,151)	430,216
Jul-26	-	81,171,892	(53,538,367)	430,216
Aug-26	-	81,171,892	(53,968,583)	430,216
Sep-26	-	81,171,892	(54,398,800)	430,216
Oct-26	-	81,171,892	(54,829,016)	430,216
Nov-26	-	81,171,892	(55,259,232)	430,216
Dec-26	-	81,171,892	(55,689,449)	430,216
Jan-27	-	81,171,892	(56,119,665)	430,216
Feb-27	-	81,171,892	(56,549,881)	430,216
Mar-27	-	81,171,892	(56,980,098)	430,216
Apr-27	-	81,171,892	(57,410,314)	430,216
May-27	-	81,171,892	(57,840,531)	430,216
Jun-27	-	81,171,892	(58,270,747)	430,216
Jul-27	-	81,171,892	(58,700,963)	430,216
Aug-27	-	81,171,892	(59,131,180)	430,216
Sep-27	-	81,171,892	(59,561,396)	430,216
Oct-27	-	81,171,892	(59,991,612)	430,216
Nov-27	-	81,171,892	(60,421,829)	430,216
Dec-27	-	81,171,892	(60,852,045)	430,216
Dec-27 13-Month Average		**81,171,892**	**(58,270,747)**	**Ref 8.12.1**

Composite Steam Depreciation Rate 6.360%

PacifiCorp
Oregon General Rate Case - December 2027
Emissions Control Equipment Disallowances
Jim Bridger Unit 3 & 4 SCR Return Disallowance

Restating Adjustment

	Total Co.
Net Book Value - Year End June 2025	70,693,836
	Ref 8.12.4
Pre-Tax Rate of Return	9.14%
Return on Rate Base_Rate of Return	6,458,743
Return - Cost of Long-Term Debt	5.41%
Return on Rate Base_Cost of Debt	3,824,537
Approx. Revenue Requirement Reduction	**(2,634,206)**
	Ref 8.12

Pro Forma Adjustment

	Total Co.
Net Book Value - 13-Month Average December 2027	41,665,314
	Ref 8.12.4
Pre-Tax Rate of Return	9.14%
Return on Rate Base_Rate of Return	3,806,634
Return - Cost of Long-Term Debt	5.41%
Return on Rate Base_Cost of Debt	2,254,093
Approx. Revenue Reuqirement Reduction	(1,552,540)
Pro Forma Adj. to Revenue Requirement Red.	**1,081,666**
	Ref 8.12

PacifiCorp
Oregon General Rate Case - December 2027
Emissions Control Equipment Adjustments
Jim Bridger Unit 3 & 4 SCR Net Book Value

	Gross Plant	Depreciation Reserve	Depreciation Expense
Jun-24	228,208,823	(133,637,610)	1,989,781
Jul-24	228,208,823	(135,627,392)	1,989,781
Aug-24	228,208,823	(137,617,173)	1,989,781
Sep-24	228,208,823	(139,606,954)	1,989,781
Oct-24	228,208,823	(141,596,736)	1,989,781
Nov-24	228,208,823	(143,586,517)	1,989,781
Dec-24	228,208,823	(145,576,299)	1,989,781
Jan-25	228,208,823	(147,566,080)	1,989,781
Feb-25	228,208,823	(149,555,861)	1,989,781
Mar-25	228,208,823	(151,545,643)	1,989,781
Apr-25	228,208,823	(153,535,424)	1,989,781
May-25	228,208,823	(155,525,205)	1,989,781
Jun-25	228,208,823	(157,514,987)	1,989,781
Year End	228,208,823	(157,514,987)	

Jun-25 Year End Undepreciated Balance 70,693,836 Ref 8.12.2

	Pro Forma Capital Addition	Gross Plant	Depreciation Reserve	Depreciation Expense
Jul-25	-	228,208,823	(158,724,508)	1,209,522
Aug-25	-	228,208,823	(159,934,030)	1,209,522
Sep-25	-	228,208,823	(161,143,552)	1,209,522
Oct-25	-	228,208,823	(162,353,074)	1,209,522
Nov-25	-	228,208,823	(163,562,596)	1,209,522
Dec-25	-	228,208,823	(164,772,117)	1,209,522
Jan-26	-	228,208,823	(165,981,639)	1,209,522
Feb-26	-	228,208,823	(167,191,161)	1,209,522
Mar-26	-	228,208,823	(168,400,683)	1,209,522
Apr-26	-	228,208,823	(169,610,204)	1,209,522
May-26	-	228,208,823	(170,819,726)	1,209,522
Jun-26	-	228,208,823	(172,029,248)	1,209,522
Jul-26	-	228,208,823	(173,238,770)	1,209,522
Aug-26	-	228,208,823	(174,448,292)	1,209,522
Sep-26	-	228,208,823	(175,657,813)	1,209,522
Oct-26	-	228,208,823	(176,867,335)	1,209,522
Nov-26	-	228,208,823	(178,076,857)	1,209,522
Dec-26	-	228,208,823	(179,286,379)	1,209,522
Jan-27	-	228,208,823	(180,495,900)	1,209,522
Feb-27	-	228,208,823	(181,705,422)	1,209,522
Mar-27	-	228,208,823	(182,914,944)	1,209,522
Apr-27	-	228,208,823	(184,124,466)	1,209,522
May-27	-	228,208,823	(185,333,988)	1,209,522
Jun-27	-	228,208,823	(186,543,509)	1,209,522
Jul-27	-	228,208,823	(187,753,031)	1,209,522
Aug-27	-	228,208,823	(188,962,553)	1,209,522
Sep-27	-	228,208,823	(190,172,075)	1,209,522
Oct-27	-	228,208,823	(191,381,596)	1,209,522
Nov-27	-	228,208,823	(192,591,118)	1,209,522
Dec-27	-	228,208,823	(193,800,640)	1,209,522
Dec-27 13-Month Average		228,208,823	(186,543,509)	

Dec-27 13MA Undepreciated Balance **41,665,314** **Ref 8.12.3**

Composite Steam Depreciation Rate 6.360%

PacifiCorp
Oregon General Rate Case - December 2027
Summary of Variables

Capital Structure and Costs

	Capital Structure	Embedded Cost	Weighted Cost	Tax Net-to-Gross Bump-up	Pre-Tax Revenue Requirement
Debt	50.00%	5.410%	2.705%		2.705%
Preferred	0.00%	6.750%	0.000%	132.60%	0.000%
Common	50.00%	9.700%	4.850%	132.60%	6.431%
Total	100.00%		7.555%		9.136%

Merged Effective Tax Rate	24.587%
Pre-Tax Bump-up Factor	132.60%

2020 Protocol Allocation Factor

2027 SG Factor	27.7556%

PacifiCorp
Oregon General Rate Case - December 2027
Transmission Project Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Transmission	352	3	(223,379)	SG	27.756%	(62,000)	8.13.1
Transmission	355	3	(35,988,271)	SG	27.756%	(9,988,752)	8.13.3
Distribution	361	3	(120,000)	OR	Situs	(120,000)	8.13.2
			(36,331,650)			(10,170,752)	
Adjustment to Reserve:							
Transmission	108TP	3	33,912	SG	27.756%	9,412	8.13.1
Transmission	108TP	3	1,551,851	SG	27.756%	430,725	8.13.3
Distribution	108364	3	36,189	OR	Situs	36,189	8.13.2
			1,621,951			476,326	
Adjustment to Tax:							
ADIT - Transmission	282	3	6,750	OR	Situs	6,750	
ADIT - Transmission	282	3	554,742	OR	Situs	554,742	
ADIT - Distribution	282	3	10,105	OR	Situs	10,105	
			571,597			571,597	

Description of Adjustment:

Rate base disallowances for transmission projects per Order No. 20-473, Docket No. UE 374 and Order No. 24-447, Docket No. UE 433.

PacifiCorp
Oregon General Rate Case - December 2027
Transmission Project Adjustment

Wallula-to-McNary Project

In-Service Date	Jan-19
Depreciation Composite Rate	1.875% UE-374, effective 1/1/2021
Depreciation Composite Rate	1.724% UE-399, effective 1/1/2023
Depreciation Composite Rate	1.725% UE-433, effective 1/1/2025

		* Gross Plant	Depreciation Expense	Depreciation Reserve	Net Book Value	
2025	January	62,000	89	(6,828)	55,172	
	February	62,000	89	(6,917)	55,083	
	March	62,000	89	(7,006)	54,994	
	April	62,000	89	(7,095)	54,905	
	May	62,000	89	(7,184)	54,816	
	June	62,000	89	(7,274)	54,726	
	July	62,000	89	(7,363)	54,637	
	August	62,000	89	(7,452)	54,548	
	September	62,000	89	(7,541)	54,459	
	October	62,000	89	(7,630)	54,370	
	November	62,000	89	(7,719)	54,281	
	December	62,000	89	(7,808)	54,192	
2026	January	62,000	89	(7,897)	54,103	
	February	62,000	89	(7,986)	54,014	
	March	62,000	89	(8,076)	53,924	
	April	62,000	89	(8,165)	53,835	
	May	62,000	89	(8,254)	53,746	
	June	62,000	89	(8,343)	53,657	
	July	62,000	89	(8,432)	53,568	
	August	62,000	89	(8,521)	53,479	
	September	62,000	89	(8,610)	53,390	
	October	62,000	89	(8,699)	53,301	
	November	62,000	89	(8,789)	53,211	
	December	62,000	89	(8,878)	53,122	
2027	January	62,000	89	(8,967)	53,033	
	February	62,000	89	(9,056)	52,944	
	March	62,000	89	(9,145)	52,855	
	April	62,000	89	(9,234)	52,766	
	May	62,000	89	(9,323)	52,677	
	June	62,000	89	(9,412)	52,588	
	July	62,000	89	(9,501)	52,499	
	August	62,000	89	(9,591)	52,409	
	September	62,000	89	(9,680)	52,320	
	October	62,000	89	(9,769)	52,231	
	November	62,000	89	(9,858)	52,142	
	December	62,000	89	(9,947)	52,053	
13 month average		**62,000**		**(9,412)**		**Ref. 8.13**

* Oregon's allocated amount

PacifiCorp
Oregon General Rate Case - December 2027
Transmission Project Adjustment

Threemile Canyon Project

In-Service Date	Apr-15	
Depreciation Composite Rate	2.585%	UE-374, effective 1/1/2021
Depreciation Composite Rate	2.271%	UE-399, effective 1/1/2023
Depreciation Composite Rate	2.276%	UE-433, effective 1/1/2025

		Gross Plant	Depreciation Expense	Depreciation Reserve	Net Book Value	
2025	January	120,000	228	(29,589)	90,411	
	February	120,000	228	(29,817)	90,183	
	March	120,000	228	(30,044)	89,956	
	April	120,000	228	(30,272)	89,728	
	May	120,000	228	(30,499)	89,501	
	June	120,000	228	(30,727)	89,273	
	July	120,000	228	(30,954)	89,046	
	August	120,000	228	(31,182)	88,818	
	September	120,000	228	(31,410)	88,590	
	October	120,000	228	(31,637)	88,363	
	November	120,000	228	(31,865)	88,135	
	December	120,000	228	(32,092)	87,908	
2026	January	120,000	228	(32,320)	87,680	
	February	120,000	228	(32,547)	87,453	
	March	120,000	228	(32,775)	87,225	
	April	120,000	228	(33,003)	86,997	
	May	120,000	228	(33,230)	86,770	
	June	120,000	228	(33,458)	86,542	
	July	120,000	228	(33,685)	86,315	
	August	120,000	228	(33,913)	86,087	
	September	120,000	228	(34,141)	85,859	
	October	120,000	228	(34,368)	85,632	
	November	120,000	228	(34,596)	85,404	
	December	120,000	228	(34,823)	85,177	
2027	January	120,000	228	(35,051)	84,949	
	February	120,000	228	(35,278)	84,722	
	March	120,000	228	(35,506)	84,494	
	April	120,000	228	(35,734)	84,266	
	May	120,000	228	(35,961)	84,039	
	June	120,000	228	(36,189)	83,811	
	July	120,000	228	(36,416)	83,584	
	August	120,000	228	(36,644)	83,356	
	September	120,000	228	(36,871)	83,129	
	October	120,000	228	(37,099)	82,901	
	November	120,000	228	(37,327)	82,673	
	December	120,000	228	(37,554)	82,446	
13 month average		**120,000**		**(36,189)**		**Ref. 8.13**

PacifiCorp
Oregon General Rate Case - December 2027
Transmission Project Adjustment

Wildfire Mitigation - Transmission (Non-OR)
In-Service Date Jan-25
Depreciation Composite Rate 1.725% UE-433, effective 1/1/2025

		*	Gross Plant	Depreciation Expense	Depreciation Reserve	Net Book Value	
2025	January		9,988,752	14,358	(14,358)	9,974,394	
	February		9,988,752	14,358	(28,715)	9,960,037	
	March		9,988,752	14,358	(43,073)	9,945,679	
	April		9,988,752	14,358	(57,430)	9,931,322	
	May		9,988,752	14,358	(71,788)	9,916,964	
	June		9,988,752	14,358	(86,145)	9,902,606	
	July		9,988,752	14,358	(100,503)	9,888,249	
	August		9,988,752	14,358	(114,860)	9,873,891	
	September		9,988,752	14,358	(129,218)	9,859,534	
	October		9,988,752	14,358	(143,575)	9,845,176	
	November		9,988,752	14,358	(157,933)	9,830,819	
	December		9,988,752	14,358	(172,290)	9,816,461	
2026	January		9,988,752	14,358	(186,648)	9,802,104	
	February		9,988,752	14,358	(201,005)	9,787,746	
	March		9,988,752	14,358	(215,363)	9,773,389	
	April		9,988,752	14,358	(229,720)	9,759,031	
	May		9,988,752	14,358	(244,078)	9,744,674	
	June		9,988,752	14,358	(258,435)	9,730,316	
	July		9,988,752	14,358	(272,793)	9,715,959	
	August		9,988,752	14,358	(287,150)	9,701,601	
	September		9,988,752	14,358	(301,508)	9,687,244	
	October		9,988,752	14,358	(315,865)	9,672,886	
	November		9,988,752	14,358	(330,223)	9,658,529	
	December		9,988,752	14,358	(344,580)	9,644,171	
2027	January		9,988,752	14,358	(358,938)	9,629,814	
	February		9,988,752	14,358	(373,295)	9,615,456	
	March		9,988,752	14,358	(387,653)	9,601,099	
	April		9,988,752	14,358	(402,010)	9,586,741	
	May		9,988,752	14,358	(416,368)	9,572,384	
	June		9,988,752	14,358	(430,725)	9,558,026	
	July		9,988,752	14,358	(445,083)	9,543,669	
	August		9,988,752	14,358	(459,440)	9,529,311	
	September		9,988,752	14,358	(473,798)	9,514,954	
	October		9,988,752	14,358	(488,155)	9,500,596	
	November		9,988,752	14,358	(502,513)	9,486,239	
	December		9,988,752	14,358	(516,870)	9,471,881	
13 month average			**9,988,752**		**(430,725)**		**Ref. 8.13**

** Oregon's allocated amount disallowed per Order No. 24-447, UE 433*

PacifiCorp PAGE 8.14
Oregon General Rate Case - December 2027
Cholla Unit 4 Retirement

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense							
Remove Safe Harbor Amort. Expense	931	1	(9,837)	OR	Situs	(9,837)	8.14.2
Remove Nonunion Severence Amort. Exp.	920	1	(187,213)	OR	Situs	(187,213)	8.14.3
Adjustment to Rate Base:							
Remove Base Period Nonunion Severance	182M	1	(531,557)	SG	27.756%	(147,537)	8.14.1
Remove Base Period Safe Harbor Lease	182M	1	(28,851)	SG	27.756%	(8,008)	8.14.1

Consistent with the Company's Integrated Resource Plan, Cholla Unit 4 ceased operations December 31, 2020. As part of the December 2021 Oregon General Rate Case, the Oregon Commission authorized the Company to use deferred tax benefits as of December 31, 2020 to offset Cholla Unit 4 unrecovered plant balance, decommissioning and a portion of closure cost. Subsequently, as part of the settlement outcome adopted in the December 2023 Oregon General Rate Case, the Company was authorized to begin amortization of the remaining unrecovered closure costs over a three-year amortization period.

The remaining Cholla unrecovered balances will be fully amortized by the end of calendar 2025.This adjustment removes per books regulatory asset balances from base period results.

PacifiCorp
Oregon General Rate Case - December 2027
Cholla Unit 4 Retirement
Historical Period Book Balances

	FERC account			EOP June 2025
Reg Asset-Cholla U4-Nonunion Severance	182M	SG	**$**	**531,557**
Reg Asset-Cholla U4-Safe Harbor Lease	182M	SG	**$**	**28,851**

Ref 8.14

PacifiCorp
Oregon General Rate Case - December 2027
Cholla Unit 4 Retirement
Treatment of Cholla Unrecovered Closure Items

	Total Company	Oregon Allocated	
	UE-399 Approved	**UE-399 Approved**	**Dec-27 13 MA Bal.**
Safe Harbor Lease Payment	113,495	29,511	**-**

Ref. 8.14

	Oregon Allocated		
	June-25 13 MA Bal.	**Dec-27 13 MA Bal.**	**Adjustment**
Safe Harbor Lease Amort.	9,837	-	**(9,837)**

Ref. 8.14

UE-399 Approved SG Allocation Factor 26.002%

	OR Alloc. Safe Harbor Lease Pmt	Amortization Total	End Bal		Schedule M	41110	Acc. 286920 283 ADIT *
Dec-25	820	(820)	(0)		820	(207)	21
Jan-26	-	-	-		-	-	-
Feb-26	-	-	-		-	-	-
Mar-26	-	-	-		-	-	-
Apr-26	-	-	-		-	-	-
May-26	-	-	-		-	-	-
Jun-26	-	-	-		-	-	-
Jul-26	-	-	-		-	-	-
Aug-26	-	-	-		-	-	-
Sep-26	-	-	-		-	-	-
Oct-26	-	-	-		-	-	-
Nov-26	-	-	-		-	-	-
Dec-26	-	-	-		-	-	-
Jan-27	-	-	-		-	-	-
Feb-27	-	-	-		-	-	-
Mar-27	-	-	-		-	-	-
Apr-27	-	-	-		-	-	-
May-27	-	-	-		-	-	-
Jun-27	-	-	-		-	-	-
Jul-27	-	-	-		-	-	-
Aug-27	-	-	-		-	-	-
Sep-27	-	-	-		-	-	-
Oct-27	-	-	-		-	-	-
Nov-27	-	-	-		-	-	-
Dec-27	-	-	-		-	-	-
Amort exp. 12 ME Dec-27		**-**	-	**13 MA Bal.**	**-**	**-**	**-**

**Tax balances are allocated NUTIL*

PacifiCorp
Oregon General Rate Case - December 2027
Cholla Unit 4 Retirement
Treatment of Cholla Unrecovered Closure Items

	Total Company	Oregon Allocated	
	UE-399 Approved	**UE-399 Approved**	**Dec-27 13 MA Bal.**
Nonunion Severance Balance	2,700,000	702,048	**-**

	Oregon Allocated		
	June-25 13 MA Bal.	**Dec-27 13 MA Bal.**	**Adjustment**
Nonunion Severance Amortization	187,213	-	**(187,213)**
			Ref. 8.14

UE-399 Approved SG Allocation Factor 26.002%

Oregon-Allocated

	Beg Bal	True-Up	Amortization	End Bal		Schedule M	41110	Acc. 286920 283 ADIT *
Dec-25	11,701		(11,701)	(0)		11,701	(2,875)	(23,008)
Jan-26	-		-	-		-	-	-
Feb-26	-		-	-		-	-	-
Mar-26	-		-	-		-	-	-
Apr-26	-		-	-		-	-	-
May-26	-		-	-		-	-	-
Jun-26	-		-	-		-	-	-
Jul-26	-		-	-		-	-	-
Aug-26	-		-	-		-	-	-
Sep-26	-		-	-		-	-	-
Oct-26	-		-	-		-	-	-
Nov-26	-		-	-		-	-	-
Dec-26	-		-	-		-	-	-
Jan-27	-		-	-		-	-	-
Feb-27	-		-	-		-	-	-
Mar-27	-		-	-		-	-	-
Apr-27	-		-	-		-	-	-
May-27	-		-	-		-	-	-
Jun-27	-		-	-		-	-	-
Jul-27	-		-	-		-	-	-
Aug-27	-		-	-		-	-	-
Sep-27	-		-	-		-	-	-
Oct-27	-		-	-		-	-	-
Nov-27	-		-	-		-	-	-
Dec-27	-		-	-		-	-	-
	Amort exp. 12 ME Dec-27		**-**	-	**13 MA Bal.**	**-**	**-**	**-**

**Tax balances are allocated NUTIL*

PacifiCorp PAGE 8.15
Oregon General Rate Case - December 2027
Miscellaneous Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
1 - Fuel Stock - Pro Forma	151	3	49,435,658	SE	26.823%	13,260,021	8.15.1
2 - Fuel Stock - Working Capital Deposit	25316	3	(6,559,077)	SE	26.823%	(1,759,327)	8.15.1
2 - Fuel Stock - Working Capital Deposit	25317	3	(5,684,852)	SE	26.823%	(1,524,836)	8.15.1
3 - Prepaid Overhauls	186M	3	(1,396,007)	SG	27.756%	(387,470)	8.15.1

Description of Adjustment:

This adjustment: (1) Walks forward to the pro-forma level of fuel stock; (2) reflects pro-forma working capital deposits; and (3) walks forward the balances for prepaid overhauls at the Lake Side, Chehalis and Currant Creek gas plants to reflect payments and transfers of capital to electric plant in service during the year ending December 2027.

PacifiCorp
Oregon General Rate Case - December 2027
Miscellaneous Rate Base
Summary of Balances

1 - Coal Fuel Stock Balances by Plant	**Account**	**Factor**	Actuals **Jun-2025 EOP Balance**	Pro Forma **Dec-2027 13-Mth. Avg. Balance**	**Adjustment**	
Jim Bridger	151	SE	38,272,751	43,671,596	5,398,845	
Colstrip	151	SE	2,328,025	2,638,288	310,263	
Craig	151	SE	4,676,383	9,315,812	4,639,429	
Hayden	151	SE	549,512	6,026,813	5,477,301	
Hunter	151	SE	106,935,868	146,429,274	39,493,405	
Huntington	151	SE	75,986,586	60,455,970	(15,530,616)	
Dave Johnston	151	SE	14,755,121	15,504,215	749,094	
Naughton	151	SE	15,367,195	-	(15,367,195)	
Rock Garden	151	SE	35,414,621	59,679,752	24,265,131	
Total			294,286,062	343,721,720	**49,435,658**	**Ref. 8.15**

1 - Working Capital Deposits	**Account**	**Factor**	Actuals **Jun-2025 EOP Balance**	Pro Forma **Dec-2027 13-Mth. Avg. Balance**	**Adjustment**	
UAMPS Working Capital Deposit	25316	SE	-	(6,559,077)	**(6,559,077)**	**Ref. 8.15**
DPEC Working Capital Deposit	25317	SE	-	(5,684,852)	**(5,684,852)**	**Ref. 8.15**

2 - Overhaul Prepayments by Plant	**Account**	**Factor**	Actuals **Jun-2025 EOP Balance**	Pro Forma **Dec-2027 13-Mth. Avg. Balance**	**Adjustment**	
Lake Side 1	186M	SG	430,240	15,703,604	15,273,364	
Chehalis	186M	SG	22,139,612	12,829,703	(9,309,909)	
Currant Creek	186M	SG	23,886,735	8,300,247	(15,586,488)	
Lake Side 2	186M	SG	11,539,319	20,773,061	9,233,742	
Chehalis O&M	186M	SG	2,249,341	1,085,230	(1,164,111)	
Currant Creek O&M	186M	SG	1,060,568	1,217,962	157,394	
Total			61,305,814	59,909,807	**(1,396,007)**	**Ref. 8.15**

PacifiCorp PAGE 8.16
Oregon General Rate Case - December 2027
Carbon Plant Closure

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Obsolete M&S Inventory Amort.	407	1	(179,487)	OR	Situs	(179,487)	8.16.1
Adjustment to Rate Base:							
Remove M&S Obsolete Inventory	182M	1	(3,446,305)	SG	27.756%	(956,542)	B-16
Remove M&S Obsolete Inventory	182M	1	807,692	OR	Situs	807,692	B-16
Adjustment to Tax:							
Accumulated Def Inc Tax Balance	283	1	22,065	SG	27.756%	6,124	B-19

Description of Adjustment:

The Carbon Plant was retired April, 2015 and fully recovered as of December 2020. A five-year amortization schedule of the excess decommissioniong costs per the proposal in the Company's 2018 Depreciation Studay, UM 1968, net of obsolete materials and supplies, was approved in the Company's general rate case Docket No. UE 374, in Order 20-473, effective January 1, 2021. This net balance was fully amortized as of January 1, 2026. This adjustment removes any residual balances related to Carbon plant net amortizations

PacifiCorp
Oregon General Rate Case - December 2027
Carbon Plant Closure
Closing Costs in Pro Forma Period

This amortization schedule of the excess decommissioning costs, net of obsolete materials and supplies, over a five-year period was approved in the Company's general rate case Docket No. UE 374, in Order 20-473.

Closure Cost	Total Company	*Allocation	OR Allocated
M&S Obsolete Inventory	3,448,669	26.023%	897,435
Decommissioning Reserve			(8,976,188)
Total Closure Cost			(8,078,754)

*Allocation on approved SG factor from UE-374 OR GRC

Date	Beg Bal	Amortization	End Bal
Jan-24	(3,590,475)	149,603	(3,440,872)
Feb-24	(3,440,872)	149,603	(3,291,269)
Mar-24	(3,291,269)	149,603	(3,141,666)
Apr-24	(3,141,666)	149,603	(2,992,063)
May-24	(2,992,063)	149,603	(2,842,460)
Jun-24	(2,842,460)	149,603	(2,692,856)
Jul-24	(2,692,856)	149,603	(2,543,253)
Aug-24	(2,543,253)	149,603	(2,393,650)
Sep-24	(2,393,650)	149,603	(2,244,047)
Oct-24	(2,244,047)	149,603	(2,094,444)
Nov-24	(2,094,444)	149,603	(1,944,841)
Dec-24	(1,944,841)	149,603	(1,795,238)
Jan-25	(1,795,238)	149,603	(1,645,635)
Feb-25	(1,645,635)	149,603	(1,496,031)
Mar-25	(1,496,031)	149,603	(1,346,428)
Apr-25	(1,346,428)	149,603	(1,196,825)
May-25	(1,196,825)	149,603	(1,047,222)
Jun-25	(1,047,222)	149,603	(897,619)
Jul-25	(897,619)	149,603	(748,016)
Aug-25	(748,016)	149,603	(598,413)
Sep-25	(598,413)	149,603	(448,809)
Oct-25	(448,809)	149,603	(299,206)
Nov-25	(299,206)	149,603	(149,603)
Dec-25	(149,603)	149,603	0

Date	Beg Bal	Amortization	End Bal
Jan-24	358,974	(14,957)	344,017
Feb-24	344,017	(14,957)	329,059
Mar-24	329,059	(14,957)	314,102
Apr-24	314,102	(14,957)	299,145
May-24	299,145	(14,957)	284,188
Jun-24	284,188	(14,957)	269,230
Jul-24	269,230	(14,957)	254,273
Aug-24	254,273	(14,957)	239,316
Sep-24	239,316	(14,957)	224,359
Oct-24	224,359	(14,957)	209,401
Nov-24	209,401	(14,957)	194,444
Dec-24	194,444	(14,957)	179,487
Jan-25	179,487	(14,957)	164,530
Feb-25	164,530	(14,957)	149,572
Mar-25	149,572	(14,957)	134,615
Apr-25	134,615	(14,957)	119,658
May-25	119,658	(14,957)	104,701
Jun-25	104,701	(14,957)	89,743
Jul-25	89,743	(14,957)	74,786
Aug-25	74,786	(14,957)	59,829
Sep-25	59,829	(14,957)	44,872
Oct-25	44,872	(14,957)	29,914
Nov-25	29,914	(14,957)	14,957
Dec-25	14,957	(14,957)	(0)

Amortization Expense	Amount	Alloc.
June 2025 Amort. Exp	(1,795,238)	NUTIL
December 2027 Amort. Exp	-	
Pro Forma Adjustment	1,795,238	

Amortization Expense	Amount	Alloc.
June 2025 Amort. Exp	179,487	OR
December 2027 Amort. Exp	-	
Total Adjustment	**(179,487)**	
	Ref. 8.16	

Excess Decommissioning Reserves	
December 2027 13MA	-
	Ref 8.16.1

Obsolete M&S Inventory	
December 2027 13MA	-
	Ref 8.16.1

PacifiCorp PAGE 8.17
Oregon General Rate Case - December 2027
Removal of Wildfire Mitigation Capital Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Transmission Plant	353	3	(4,505,980)	SG	27.756%	(1,250,661)	
Distribution Plant	360	3	(1,639,862)	OR	100.000%	(1,639,862)	
Distribution Plant	361	3	(3,125,147)	OR	100.000%	(3,125,147)	
Distribution Plant	362	3	(25,975,244)	OR	100.000%	(25,975,244)	
Distribution Plant	363	3	(4,200,265)	OR	100.000%	(4,200,265)	
Distribution Plant	364	3	(37,003,218)	OR	100.000%	(37,003,218)	
Distribution Plant	365	3	(23,774,095)	OR	100.000%	(23,774,095)	
Distribution Plant	366	3	(11,035,678)	OR	100.000%	(11,035,678)	
Distribution Plant	367	3	(25,408,771)	OR	100.000%	(25,408,771)	
Distribution Plant	368	3	(34,933,787)	OR	100.000%	(34,933,787)	
Distribution Plant	369	3	(22,444,558)	OR	100.000%	(22,444,558)	
Distribution Plant	370	3	(6,444,561)	OR	100.000%	(6,444,561)	
Distribution Plant	371	3	(177,402)	OR	100.000%	(177,402)	
Distribution Plant	373	3	(1,333,221)	OR	100.000%	(1,333,221)	
General Plant	397	3	(88,648,623)	SO	28.253%	(25,045,717)	
General Plant	397	3	(2,121,905)	OR	100.000%	(2,121,905)	
General Plant	397	3	(3,254,096)	SG	27.756%	(903,193)	
			(296,026,416)			(226,817,287)	8.17.3
Adjustment to Depreciation Reserve:							
Transmission Depreciation Reserve	108TP	3	486,968	SG	27.7556%	135,161	
Distribution Depreciation Reserve	108360	3	111,353	OR	100.0000%	111,353	
Distribution Depreciation Reserve	108361	3	212,209	OR	100.0000%	212,209	
Distribution Depreciation Reserve	108362	3	1,763,819	OR	100.0000%	1,763,819	
Distribution Depreciation Reserve	108363	3	285,214	OR	100.0000%	285,214	
Distribution Depreciation Reserve	108364	3	2,512,660	OR	100.0000%	2,512,660	
Distribution Depreciation Reserve	108365	3	1,614,352	OR	100.0000%	1,614,352	
Distribution Depreciation Reserve	108366	3	749,365	OR	100.0000%	749,365	
Distribution Depreciation Reserve	108367	3	1,725,353	OR	100.0000%	1,725,353	
Distribution Depreciation Reserve	108368	3	2,372,138	OR	100.0000%	2,372,138	
Distribution Depreciation Reserve	108369	3	1,524,072	OR	100.0000%	1,524,072	
Distribution Depreciation Reserve	108370	3	437,610	OR	100.0000%	437,610	
Distribution Depreciation Reserve	108371	3	12,046	OR	100.0000%	12,046	
Distribution Depreciation Reserve	108373	3	90,531	OR	100.0000%	90,531	
General Depreciation Reserve	108GP	3	26,454,482	SO	28.2528%	7,474,131	
General Depreciation Reserve	108GP	3	324,698	OR	100.0000%	324,698	
General Depreciation Reserve	108GP	3	503,249	SG	27.756%	139,680	
			41,180,120			21,484,393	8.17.3

This adjustment removes the gross plant, depreciation expense and accumulated depreciation reserve amounts included in the Test Year that are associated with June 2025 YE base period assets eligible for recovery under Oregon's Wildfire Mitigation Plan Automatic Adjustment Clause. This treatment is consistent with Advice No. 23-015, in Docket ADV 1629 dated January 9, 2024, and the final order in the company's 2025 general rate case, docket UE 433, Order No. 24-447.

PacifiCorp PAGE 8.17.1
Oregon General Rate Case - December 2027
Removal of Wildfire Mitigation Capital Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Depreciation Expense:							
Transmission Depreciation	403TP	3	(79,759)	SG	27.7556%	(22,137)	
Distribution Depreciation	403360	3	(38,367)	OR	100.0000%	(38,367)	
Distribution Depreciation	403361	3	(73,117)	OR	100.0000%	(73,117)	
Distribution Depreciation	403362	3	(607,728)	OR	100.0000%	(607,728)	
Distribution Depreciation	403363	3	(98,271)	OR	100.0000%	(98,271)	
Distribution Depreciation	403364	3	(865,743)	OR	100.0000%	(865,743)	
Distribution Depreciation	403365	3	(556,229)	OR	100.0000%	(556,229)	
Distribution Depreciation	403366	3	(258,195)	OR	100.0000%	(258,195)	
Distribution Depreciation	403367	3	(594,475)	OR	100.0000%	(594,475)	
Distribution Depreciation	403368	3	(817,326)	OR	100.0000%	(817,326)	
Distribution Depreciation	403369	3	(525,123)	OR	100.0000%	(525,123)	
Distribution Depreciation	403370	3	(150,780)	OR	100.0000%	(150,780)	
Distribution Depreciation	403371	3	(4,151)	OR	100.0000%	(4,151)	
Distribution Depreciation	403372	3	-	OR	100.0000%	-	
Distribution Depreciation	403373	3	(31,193)	OR	100.0000%	(31,193)	
General Depreciation	108GP	3	(5,653,118)	SO	28.2528%	(1,597,164)	
General Depreciation	108GP	3	(30,038)	OR	100.0000%	(30,038)	
General Depreciation	108GP	3	(84,150)	SG	27.756%	(23,356)	
			(10,467,761)			(6,293,393)	8.17.3
Tax Impacts:							
Schedule M - Book Depreciation	SCHMAT	3	(413,888)	OR	100.0000%	(413,888)	
Schedule M - Book Depreciation	SCHMAT	3	(16,732)	SG	27.7556%	(4,644)	
Schedule M - Book Depreciation	SCHMAT	3	(1,285,159)	SO	28.2528%	(363,093)	
Schedule M - Tax Depreciation	SCHMDT	3	(12,590,418)	OR	100.0000%	(12,590,418)	
Schedule M - Tax Depreciation	SCHMDT	3	(355,552)	SG	27.7556%	(98,685)	
Schedule M - Tax Depreciation	SCHMDT	3	(11,351,656)	SO	28.2528%	(3,207,161)	
DIT Expense	41110	3	101,761	OR	100.0000%	101,761	
DIT Expense	41110	3	4,114	SG	27.7556%	1,142	
DIT Expense	41110	3	315,976	SO	28.2528%	89,272	
DIT Expense	41010	3	(3,095,555)	OR	100.0000%	(3,095,555)	
DIT Expense	41010	3	(87,418)	SG	27.7556%	(24,263)	
DIT Expense	41010	3	(2,790,986)	SO	28.2528%	(788,532)	
ADIT	282	3	8,126,845	OR	100.0000%	8,126,845	
ADIT	282	3	1,177,168	SG	27.7556%	326,730	
ADIT	282	3	9,288,072	SO	28.2528%	2,624,140	

This adjustment removes the gross plant, depreciation expense and accumulated depreciation reserve amounts included in the Test Year that are associated with June 2025 YE base period assets eligible for recovery under Oregon's Wildfire Mitigation Plan Automatic Adjustment Clause. This treatment is consistent with Advice No. 23-015, in Docket ADV 1629 dated January 9, 2024, and the final order in the company's 2025 general rate case, docket UE 433, Order No. 24-447.

PacifiCorp
Oregon General Rate Case - December 2027
Removal of Wildfire Mitigation Capital Rate Base

Function	FERC Plant Account	Code	FERC Plant Account Description	EPIS Gross Plant Through June 2025	Reserve Accum. Res. Through June 2025	Net Book Value Year End June 2025
Transmission	**3520000**	SG	Structures & Improvements	30,247	(1,388)	28,859
	3513000	SG	Communication Equipment	971,734	(99,749)	871,985
	3530000	SG	Station Equipment	3,214,085	(179,248)	3,034,838
	3537000	SG	Station Equipment-Supervisory & Alarm	80,148	(4,596)	75,552
	3550000	SG	Poles and Fixtures	46,354	(2,511)	43,843
	3560000	SG	Overhead Conductors & Devices	13,608	(788)	12,820
	1062000	SG	Transmission Completed Construction Unclassified	149,803	(39,170)	110,633
Transmission Total				**4,505,980**	**(327,450)**	**4,178,530**
Distribution	**3610000**	OR	Structures & Improvements	63,907	(2,530)	61,377
	3620000	OR	Station Equipment	1,159,183	(54,171)	1,105,012
	3627000	OR	Station Equipment-Supervisory & Alarm	83,212	(4,053)	79,159
	3633000	OR	Communication Equipment	463	(3)	460
	3633000	OR	Communication Equipment	2,521,938	(134,143)	2,387,795
	3640000	OR	Poles, Towers and Fixtures	81,801,583	(1,415,160)	80,386,423
	3650000	OR	Overhead Conductors & Devices	73,894,278	(1,673,975)	72,220,303
	3660000	OR	Underground Conduit	1,600,551	(18,273)	1,582,278
	3670000	OR	Underground Conductors & Devices	626,264	(4,387)	621,877
	3680000	OR	Line Transformers	5,526,485	(102,588)	5,423,896
	3691000	OR	Services - Overhead	26	(1)	24
	3692000	OR	Services - Underground	496,196	(7,499)	488,697
	3730000	OR	Street Lighting & Signal Systems	167	(22)	145
	1061000	OR	Distribution Completed Construction Unclassified	29,721,561	(752,522)	28,969,038
Distribution Total				**197,495,812**	**(4,169,328)**	**193,326,483**
General Plant	**3900000**	SG	Structures & Improvements	2,114,755	(187,885)	1,926,870
	3900000	SO	Structures & Improvements	45,864	(4,074)	41,790
	3910000	SO	Structures & Improvements	2,604	(559)	2,045
	3920400	OR	1/2 & 3/4 Ton Pickups, Vans, Service Trucks	190,079	(65,950)	124,129
	3920900	OR	Trailers	3,276	(397)	2,879
	3921400	OR	Snowmobiles, Motorcycles (4-Wheeled ATV)	160,349	(44,014)	116,335
	3930000	OR	Stores Equipment	1,073,437	(82,173)	991,264
	3950000	OR	Laboratory Equipment	272,474	(39,286)	233,189
	3950000	SG	Laboratory Equipment	742,979	(106,379)	636,600
	3961300	OR	Snowcats, Backhoes, Trenchers, Snowblower	61,806	(13,629)	48,177
	3973001	SO	Communication Equipment	87,425	(14,725)	72,700
	3973001	OR	Communication Equipment	360,484	(19,174)	341,310
	3973001	SG	Communication Equipment	396,362	(40,687)	355,675
	3971001	SO	Computer Hardware	182,532	(97,713)	84,818
	3972001	SO	Computer Software (Misc)	77,766	(41,630)	36,136
	3972005	SO	Augmented Reality	431,455	(17,977)	413,478
	3972048	SO	ADS	2,594,073	(896,706)	1,697,367
	3972049	SO	Technosylva	24,719,978	(2,504,237)	22,215,740
	3972050	SO	Situational Awareness	1,247,254	(848,714)	398,540
	3972057	SO	Foundry	14,766,824	(6,701,633)	8,065,191
	3972058	SO	PSP - Public Safety Portal	11,076,842	(2,155,809)	8,921,033
	1064000	SO	General Completed Construction Unclassified	33,416,008	(1,864,468)	31,551,540
General Plant Total				**94,024,624**	**(15,747,818)**	**78,276,806**
EPIS Total				**296,026,416**	**(20,244,597)**	**275,781,819**
				Ref. 8.17.3	**Ref. 8.17.3**	

PacifiCorp
Oregon General Rate Case - December 2027
Removal of Wildfire Mitigation Capital Rate Base

	Jun-25	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Month Average
Gross Plant															
Transmission SG	4,505,980	4,505,980	4,505,980	4,505,980	4,505,980	4,505,980	4,505,980	4,505,980	4,505,980	4,505,980	4,505,980	4,505,980	4,505,980	4,505,980	4,505,980
Distribution OR	197,495,812	197,495,812	197,495,812	197,495,812	197,495,812	197,495,812	197,495,812	197,495,812	197,495,812	197,495,812	197,495,812	197,495,812	197,495,812	197,495,812	197,495,812
General SG	3,254,096	3,254,096	3,254,096	3,254,096	3,254,096	3,254,096	3,254,096	3,254,096	3,254,096	3,254,096	3,254,096	3,254,096	3,254,096	3,254,096	3,254,096
General SO	88,648,623	88,648,623	88,648,623	88,648,623	88,648,623	88,648,623	88,648,623	88,648,623	88,648,623	88,648,623	88,648,623	88,648,623	88,648,623	88,648,623	88,648,623
General OR	2,121,905	2,121,905	2,121,905	2,121,905	2,121,905	2,121,905	2,121,905	2,121,905	2,121,905	2,121,905	2,121,905	2,121,905	2,121,905	2,121,905	2,121,905
	296,026,416														**296,026,416**
	Ref. 8.17.2														**Ref. 8.17**

Depreciation Expense	Composite Depreciation Rate	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total Test Year Depr Expense
Transmission SG	1.77%	6,647	6,647	6,647	6,647	6,647	6,647	6,647	6,647	6,647	6,647	6,647	6,647	6,647	79,759
Distribution OR	2.34%	385,058	385,058	385,058	385,058	385,058	385,058	385,058	385,058	385,058	385,058	385,058	385,058	385,058	4,620,697
General SG	2.59%	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	84,150
General SO	6.38%	471,093	471,093	471,093	471,093	471,093	471,093	471,093	471,093	471,093	471,093	471,093	471,093	471,093	5,653,118
General OR	1.42%	2,503	2,503	2,503	2,503	2,503	2,503	2,503	2,503	2,503	2,503	2,503	2,503	2,503	30,038
															10,467,761
															Ref. 8.17

	Jun-25	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Month Average
Depreciation Reserve															
Transmission SG	(327,450)	(447,088)	(453,735)	(460,382)	(467,028)	(473,675)	(480,321)	(486,968)	(493,614)	(500,261)	(506,907)	(513,554)	(520,201)	(526,847)	(486,968)
Distribution OR	(4,169,328)	(11,100,374)	(11,485,432)	(11,870,490)	(12,255,548)	(12,640,607)	(13,025,665)	(13,410,723)	(13,795,781)	(14,180,839)	(14,565,897)	(14,950,955)	(15,336,013)	(15,721,071)	(13,410,723)
General SG	(334,950)	(461,174)	(468,187)	(475,199)	(482,212)	(489,224)	(496,237)	(503,249)	(510,262)	(517,274)	(524,287)	(531,299)	(538,312)	(545,324)	(503,249)
General SO	(15,148,245)	(23,627,922)	(24,099,016)	(24,570,109)	(25,041,202)	(25,512,295)	(25,983,388)	(26,454,482)	(26,925,575)	(27,396,668)	(27,867,761)	(28,338,854)	(28,809,947)	(29,281,041)	(26,454,482)
General OR	(264,623)	(309,679)	(312,183)	(314,686)	(317,189)	(319,692)	(322,195)	(324,698)	(327,201)	(329,705)	(332,208)	(334,711)	(337,214)	(339,717)	(324,698)
	(20,244,597)														**(41,180,120)**
	Ref. 8.17.2														**Ref 8.17**

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Oregon General Rate Case - December 2027
Dave Johnston Unit 4 Repairs

Adjustment to Rate Base - 13-Month Avg	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
New Steam Plant EPIS							
Dave Johnston Unit 4	312	3	10,000,000	SG	27.76%	2,775,557	8.18.1
Adjustment to Depreciation Expense:							
New Steam Plant DEPE							
Dave Johnston Unit 4	403SP	3	636,008	SG	27.76%	176,528	8.18.1
Adjustment to Accum. Depr. - 13-Month Avg							
New Steam Plant DEPR							
Dave Johnston Unit 4	108SP	3	(344,504)	SG	27.76%	(95,619)	8.18.1
Adjustment to Rate Base - 13-Month Avg							
Retired Steam Plant EPIS and Accum. DEPR							
Retired Steam Plant EPIS	312	3	(7,674,610)	SG	27.76%	(2,130,132)	8.18.2
Retired Steam Plant - Accum. Depr.	108SP	3	7,674,610	SG	27.76%	2,130,132	8.18.2
Adjustment to Tax							
New Steam Plant - Schedule M	SCHMAT	3	636,008	SG	27.76%	176,528	
New Steam Plant - Schedule M	SCHMDT	3	721,896	SG	27.76%	200,366	
New Steam Plant - DIT Expense	41010	3	(156,373)	SG	27.76%	(43,402)	
New Steam Plant - DIT Expense	41110	3	177,490	SG	27.76%	49,263	
New Steam Plant - ADIT	282	3	(93,766)	SG	27.76%	(26,025)	
Retired Steam Plant - Schedule M	SCHMDT	3	(72,611)	SG	27.76%	(20,154)	
Retired Steam Plant - DIT Expense	41110	3	(17,853)	SG	27.76%	(4,955)	
Retired Steam Plant - ADIT	282	3	(71,955)	SG	27.76%	(19,972)	

Description of Adjustment:

This adjustment accounts for new electric plant in-service (EPIS) and associated depreciation expense and reserve for the Dave Johnston Unit 4 refurbishment. This adjustment also accounts for the retirement of certain in-service assets that will be retired for ratemaking purposes. Tax impacts associated with these changes are also reflected in this adjustment.

PacifiCorp
Oregon General Rate Case - December 2027
Dave Johnston Unit 4 Repairs

NEW STEAM CAPITAL ADDITIONS
Dave Johnston Unit 4 Repair

Gross EPIS

Account	Factor	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Month Avg Dec-27
312SP	SG	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000

Depreciation E

		Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	CY 2027
403SP	SG	26,500	53,001	53,001	53,001	53,001	53,001	53,001	53,001	53,001	53,001	53,001	53,001	53,001	636,008

Accumulated Depreciation

		Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Month Avg Dec-27
108SP	SG	(26,500)	(79,501)	(132,502)	(185,502)	(238,503)	(291,504)	(344,504)	(397,505)	(450,506)	(503,506)	(556,507)	(609,508)	(662,508)	(344,504)

	YE June 2025	13 Mo Average Dec 2027	Adjustment	
312SP	-	10,000,000	**10,000,000**	**Ref. 8.18**
403SP	-	636,008	**636,008**	**Ref. 8.18**
108SP	-	(344,504)	**(344,504)**	**Ref. 8.18**

6.360% Composite Depreciation Rate - Steam Plant System Allocatior

PacifiCorp
Oregon General Rate Case - December 2027
Dave Johnston Unit 4 Repairs

RETIREMENT OF EXISTING STEAM PLANT
Dave Johnston Unit 4

Gross EPIS

Account	Factor	Jun-25	Dec-25	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Month Avg Dec-27
312SP	SG	**(7,674,610)**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Ref 8.18															

Depreciation Expense

		Jun-25	Dec-25	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	CY 2027
403SP	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Accumulated Depreciation

		Jun-25	Dec-25	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Month Avg Dec-27
108SP	SG	**7,674,610**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Ref 8.18															

	YE June 2025	13 Mo Average Dec 2027	Adjustment	
312SP	(7,674,610)	-	**(7,674,610)**	**Ref. 8.18**
403SP	-	-	**-**	**Ref. 8.18**
108SP	7,674,610	-	**7,674,610**	**Ref. 8.18**

6.360% Composite Depreciation Rate - Steam Plant System Allocation

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Oregon General Rate Case - December 2027
Klamath Regulatory Asset

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Base Period O&M Expense	535	1	(1,557,679)	SG	27.756%	(432,343)	8.19.1
Pro Forma Amortization Expense	407	3	(70,735)	SG	27.756%	(19,633)	8.19.2
Total Adjustment to Expense			(1,628,414)			(451,976)	
Adjustment to Rate Base							
Klamath Regulatory Asset	182M	3	(7,483,899)	SG	27.756%	(2,077,199)	8.19.2
Tax Adjustment:							
Remove base period tax:							
Schedule M Addition	SCHMDT	3	4,598,273	SG	27.756%	1,276,277	
Deferred Income Tax Expense	41010	3	1,130,559	SG	27.756%	313,793	
Accum Def Inc Tax Bal	283	3	1,840,036	SG	27.756%	510,713	

Description of Adjustment:

The Lower Klamath hydroelectric generation assets were transferred to KRRC for final decommissioning in December 2022. Accordingly, the remaining net plant balance was initially reclassified from Hydro Plant to Intangible Plant, and the company continued to assume depreciation on the intangible plant assets using a 20% rate (i.e. 5 years depreciable life) consistent with the rate requested and approved in docket UE 374 for Klamath assets. A subsequent determination from FERC denied the company's inclusion of the balance as Intangible, and the balance was then reclassified as a regulatory asset. The company continued to amortize this balance, now classified as a regulatory asset, assuming the 5 years' amortization life previously established for Klamath assets. In the company's most recently concluded general rate case, docket UE 433, the company proposed to continue this amortization through 2027, for the regulatory asset to be fully amortized five years after the balance was reclassified out of electric plant in-service (EPIS) balance at the end of 2027. This treatment was adopted into rates effective January 1, 2025 approved through Order No. 24-447. The company is also removing the regulatory asset balance from rate base, consistent with the treatment approved in docket UE 433, as these assets no longer meet the used and useful statute for Oregon customers.

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Oregon General Rate Case - December 2027
Klamath Regulatory Asset
Remove Base Period O&M Expense

	FACTOR		TOTAL COMPANY	
Expense Accounts				
Remove base period O&M expense[1]	SG	$	1,557,679	
Adjustment to Expense Accounts		**$**	**1,557,679**	**Ref 8.19**

1 The FERC Location Codes included in this line item include the following:

18000
610000
611000
612000

PacifiCorp
Oregon General Rate Case - December 2027
Klamath Regulatory Asset
Regulatory Asset Balance and Amortization

Regulatory Assets	June 2025 EOP Balance	December 2027 13 MA Balance[1]	Difference
Klamath Regulatory Asset	$ 7,483,899	$ -	**$ (7,483,899)**
	Ref B-16		**Ref 8.19**

Amortization Expense	12 ME June 2025	12 ME December 2027	Difference
Klamath Amortization Expense	$ 1,347,014	$ 1,276,279	**$ (70,735)**
	Ref 8.19.3		**Ref 8.19**

Approved Balance Eff. January 1, 2025 - Docket No. UE-433 ***3,535,423***

Date	Beg Bal	Adjustment	Amortization	Interest	End Bal
Jan-25	$ 3,535,423		$ (106,357)	15,670	$ 3,444,736
Feb-25	$ 3,444,736		$ (106,357)	15,262	$ 3,353,642
Mar-25	$ 3,353,642		$ (106,357)	14,852	$ 3,262,137
Apr-25	$ 3,262,137		$ (106,357)	14,440	$ 3,170,221
May-25	$ 3,170,221		$ (106,357)	14,027	$ 3,077,891
Jun-25	$ 3,077,891		$ (106,357)	13,611	$ 2,985,146
Jul-25	$ 2,985,146		$ (106,357)	13,194	$ 2,891,983
Aug-25	$ 2,891,983		$ (106,357)	12,775	$ 2,798,401
Sep-25	$ 2,798,401		$ (106,357)	12,354	$ 2,704,398
Oct-25	$ 2,704,398		$ (106,357)	11,930	$ 2,609,972
Nov-25	$ 2,609,972		$ (106,357)	11,506	$ 2,515,121
Dec-25	$ 2,515,121		$ (106,357)	11,079	$ 2,419,843
Jan-26	$ 2,419,843		$ (106,357)	10,650	$ 2,324,136
Feb-26	$ 2,324,136		$ (106,357)	10,219	$ 2,227,999
Mar-26	$ 2,227,999		$ (106,357)	9,787	$ 2,131,429
Apr-26	$ 2,131,429		$ (106,357)	9,352	$ 2,034,425
May-26	$ 2,034,425		$ (106,357)	8,916	$ 1,936,984
Jun-26	$ 1,936,984		$ (106,357)	8,477	$ 1,839,104
Jul-26	$ 1,839,104		$ (106,357)	8,037	$ 1,740,784
Aug-26	$ 1,740,784		$ (106,357)	7,594	$ 1,642,022
Sep-26	$ 1,642,022		$ (106,357)	7,150	$ 1,542,815
Oct-26	$ 1,542,815		$ (106,357)	6,703	$ 1,443,162
Nov-26	$ 1,443,162		$ (106,357)	6,255	$ 1,343,060
Dec-26	$ 1,343,060		$ (106,357)	5,804	$ 1,242,508
Jan-27	$ 1,242,508		$ (106,357)	5,352	$ 1,141,504
Feb-27	$ 1,141,504		$ (106,357)	4,897	$ 1,040,044
Mar-27	$ 1,040,044		$ (106,357)	4,441	$ 938,129
Apr-27	$ 938,129		$ (106,357)	3,982	$ 835,754
May-27	$ 835,754		$ (106,357)	3,522	$ 732,919
Jun-27	$ 732,919		$ (106,357)	3,059	$ 629,622
Jul-27	$ 629,622		$ (106,357)	2,594	$ 525,859
Aug-27	$ 525,859		$ (106,357)	2,127	$ 421,630
Sep-27	$ 421,630		$ (106,357)	1,658	$ 316,931
Oct-27	$ 316,931		$ (106,357)	1,187	$ 211,761
Nov-27	$ 211,761		$ (106,357)	714	$ 106,118
Dec-27	$ 106,118		$ (106,357)	238	$ 0
Annual Total			**$ (1,276,279)**		

1. Regulatory asset balance no longer to be included in rate base since January 2025 in accordance with Oregon's used and useful statute.
2. Interest accrual at Modified Blended Treasury Rate as of date of the Commission's approval of the amortization in Docket UE-433 (i.e. December 2024).

	2024	
MBTR	5.400%	Ref UM-1147

PacifiCorp Page 8.19.3

Oregon General Rate Case - December 2027

Klamath Regulatory Asset

GL Account 566940 - Klamath Unrecovered Costs Amortization

12 Months Ended June 2025

Year	Month	Description	Amortization
2024	7	Klamath Unrecovered Plant Amortization	110,414
2024	8	Klamath Unrecovered Plant Amortization	110,414
2024	9	Klamath Unrecovered Plant Amortization	110,414
2024	10	Klamath Unrecovered Plant Amortization	110,414
2024	11	Klamath Unrecovered Plant Amortization	110,414
2024	12	Klamath Unrecovered Plant Amortization	110,414
2025	1	Klamath Unrecovered Plant Amortization	110,414
2025	2	Klamath Unrecovered Plant Amortization	110,414
2025	3	Klamath Unrecovered Plant Amortization	115,926
2025	4	Klamath Unrecovered Plant Amortization	115,926
2025	5	Klamath Unrecovered Plant Amortization	115,926
2025	6	Klamath Unrecovered Plant Amortization	115,926
		12 Months Ended June 2025	**1,347,014**
			Ref 8.19.2

PacifiCorp
Oregon General Rate Case - December 2027
Confidential New Wind Generation Capital Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
New Wind Capital - Wind	338WP	3	903,601,369	SG	27.756%	250,799,753	8.20.1
Adjustment to Depreciation Expense:							
New Wind Capital - Wind Depr. Exp	403WP	3	36,063,621	SG	27.756%	10,009,665	8.20.1
Adjustment to Depreciation Reserve:							
New Wind Capital - Wind Depr. Reserve	108WP	3	(61,446,217)	SG	27.756%	(17,054,751)	8.20.1
Adjustment to Operations & Maintenance Expense:							
Incremental Wind Repowering O&M Exp	558WP	3	8,985,433	SG	27.756%	2,493,958	8.20.2
Adjustment to Tax							
Schedule M Addition	SCHMAT	3	(951,806)	SG	27.756%	(264,179)	
Schedule M Deduction	SCHMDT	3	(13,999,344)	SG	27.756%	(3,885,598)	
DIT Expense	41110	3	234,017	SG	27.756%	64,953	
DIT Expense	41010	3	(3,441,963)	SG	27.756%	(955,337)	
ADIT	282	3	(1,652,442)	SG	27.756%	(458,645)	

Description of Adjustment:

This adjustment adds into the Test Period incremental capital additions related to certain confidential capital projects. Included in this adjustment is incremental operations and maintenance expense for these confidential projects.

PacifiCorp
Oregon General Rate Case - December 2027
Confidential New Wind Generation Capital Additions

NEW WIND CAPITAL ADDITIONS

Electric Plant in Service

	Account	Factor	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Month Avg Dec-27
Wind Plant Wind	338WP	SG	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369

Depreciation Expense*

	Account	Factor	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	CY 2027
Wind Plant Wind	403WP	SG	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	36,063,621

Depreciation Reserve

	Account	Factor	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Month Avg Dec-27
Wind Plant Wind	108WP	SG	(43,414,406)	(46,419,708)	(49,425,010)	(52,430,312)	(55,435,613)	(58,440,915)	(61,446,217)	(64,451,519)	(67,456,821)	(70,462,122)	(73,467,424)	(76,472,726)	(79,478,028)	(61,446,217)

	EOP June 2025	13 Mo Average Dec 2027	Adjustment	
338WP	-	903,601,369	**903,601,369**	**Ref. 8.20**
403WP	-	36,063,621	**36,063,621**	**Ref. 8.20**
108WP	-	(61,446,217)	**(61,446,217)**	**Ref. 8.20**

*Composite Depreciation Rate - Wind

3.991% Composite Depreciation Rate - Wind

PacifiCorp Page 8.20.2_REDACTED
Oregon General Rate Case - December 2027
Confidential New Wind Generation Capital Additions

Please refer to Confidential Exhibit PAC/808 for supporting details.

Project	Date	Project Capital Amount	Ref
New Wind			
WBUILD - RMP Rock Creek I 190 MW 2024	Various	[redacted]	
WBUILD - RMP Rock Creek Wind II 400MW 2025	Various		
		903,601,369	**Ref 8.21.1**

Project	2027 O&M	
WBUILD - RMP Rock Creek I 190 MW 2024	[redacted]	
WBUILD - RMP Rock Creek Wind II 400MW 2025		
	8,985,433	**Ref 8.21**

PacifiCorp PAGE 8.21
Oregon General Rate Case - December 2027
Craig Unit 1 Retirement

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense							
Remove O&M expense	506	3	(4,802,686)	SG	27.756%	(1,333,013)	8.21.1
Remove Depr. expense	403SP	3	(4,149,748)	SG	27.756%	(1,151,787)	8.21.1
Adjustment to Rate Base							
Craig Unit 1 - Retirement	312	3	(65,246,808)	SG	27.756%	(18,109,626)	8.21.2
Craig Unit 1 - Retirement	108SP	3	65,246,808	SG	27.756%	18,109,626	

Description of Adjustment:

Docket UE 374 sets an Exit Date of December 31, 2025 for Unit 1 of the Craig generation plant. Accordingly, Craig Unit 1 was scheduled for retirement December 31, 2025. This adjustment removes the associated gross plant, O&M expense and depreciation expense from rates consistent with the Exit Order.

PacifiCorp
Oregon General Rate Case - December 2027
Craig Unit 1 Retirement
Non-EPIS Balances for Removal

	FERC account	12 ME June 2025
O&M Expense	506	$ 4,802,686

Ref 8.21

	FERC account	12 ME Dec 2027
Depreciation Expense	403SP	$ 4,149,748

Ref 8.21

PacifiCorp
Oregon General Rate Case - December 2027
Craig Unit 1 Retirement

	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Month Average
Gross Plant	65,246,808	65,246,808	65,246,808	65,246,808	65,246,808	65,246,808	65,246,808	65,246,808	65,246,808	65,246,808	65,246,808	65,246,808	65,246,808	**65,246,808**
														Ref 8.21

	Composite Depreciation Rate	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Test Year Depr Expense
Depreciation Expense	6.3601%	345,812	345,812	345,812	345,812	345,812	345,812	345,812	345,812	345,812	345,812	345,812	345,812	**4,149,748**
														Ref 8.21.1

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Oregon General Rate Case - December 2027
Remove Large Energy-Use Facilities

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base							
Transmission Plant	352	3	(30,901,699)	OR	Situs	(30,901,699)	8.22.1
Transmission Plant	352	3	(135,010,262)	OR	Situs	(135,010,262)	8.22.1
Transmission Plant	352	3	(30,851,859)	OR	Situs	(30,851,859)	8.22.1
Transmission Plant	108TP	3	686,135	OR	Situs	686,135	8.22.1
Transmission Plant	108TP	3	2,730,403	OR	Situs	2,730,403	8.22.1
Transmission Plant	108TP	3	538,850	OR	Situs	538,850	8.22.1
Adjustment to Depreciation Expense:							
Transmission Plant	403TP	3	(546,980)	OR	Situs	(546,980)	8.22.1
Transmission Plant	403TP	3	(2,389,768)	OR	Situs	(2,389,768)	8.22.1
Transmission Plant	403TP	3	(546,269)	OR	Situs	(546,269)	8.22.1
Adjustment to Tax							
Transmission - Schedule M	SCHMAT	3	(3,483,017)	OR	Situs	(3,483,017)	
Transmission - Schedule M	SCHMDT	3	(18,653,796)	OR	Situs	(18,653,796)	
Transmission - DIT Expense	41010	3	(4,586,334)	OR	Situs	(4,586,334)	
Transmission - DIT Expense	41110	3	856,356	OR	Situs	856,356	
Tarnsmission Plant - ADIT	282	3	562,330	OR	Situs	562,330	
Tarnsmission Plant - ADIT	282	3	2,402,542	OR	Situs	2,402,542	
Tarnsmission Plant - ADIT	282	3	563,454	OR	Situs	563,454	

Description of Adjustment:

This adjustment removes from Test Period results the gross plant, accumulated reserves, depreciation expense and associated tax impacts of specific capital investments embedded in the forecast data informing adjustments 8.5 - Pro Forma Plant Addition, and adjustments 6.1/6.2 - Depreciation Expense/Reserves associated with large energy-use facilities.

PacifiCorp PAGE 8.22.1
Oregon General Rate Case - December 2027
Remove Large Energy-Use Facilities
Capital Additions Forecast Details

	Gross Plant In Service				Accumulated Depreciation		
	Project Specialized	**Project Litespeed**	**Customer 7 - Trans - OR**		**Project Specialized**	**Project Litespeed**	**Customer 7 - Trans - OR**
Dec-26	30,901,699	135,010,262	30,566,733	Dec-26	(412,645)	(1,535,519)	(266,009)
Jan-27	30,901,699	135,010,262	30,668,389	Jan-27	(458,227)	(1,734,666)	(311,172)
Feb-27	30,901,699	135,010,262	30,786,806	Feb-27	(503,808)	(1,933,813)	(356,497)
Mar-27	30,901,699	135,010,262	30,905,224	Mar-27	(549,390)	(2,132,961)	(401,996)
Apr-27	30,901,699	135,010,262	30,905,224	Apr-27	(594,972)	(2,332,108)	(447,583)
May-27	30,901,699	135,010,262	30,905,224	May-27	(640,553)	(2,531,256)	(493,170)
Jun-27	30,901,699	135,010,262	30,905,224	Jun-27	(686,135)	(2,730,403)	(538,757)
Jul-27	30,901,699	135,010,262	30,905,224	Jul-27	(731,716)	(2,929,550)	(584,344)
Aug-27	30,901,699	135,010,262	30,905,224	Aug-27	(777,298)	(3,128,698)	(629,931)
Sep-27	30,901,699	135,010,262	30,905,224	Sep-27	(822,880)	(3,327,845)	(675,517)
Oct-27	30,901,699	135,010,262	30,905,224	Oct-27	(868,461)	(3,526,992)	(721,104)
Nov-27	30,901,699	135,010,262	30,905,224	Nov-27	(914,043)	(3,726,140)	(766,691)
Dec-27	30,901,699	135,010,262	30,905,224	Dec-27	(959,625)	(3,925,287)	(812,278)
13 Month Avg	**30,901,699**	**135,010,262**	**30,851,859**	**13 Month Avg**	**(686,135)**	**(2,730,403)**	**(538,850)**

	Depreciation Expense				Accumulated Deferred Income Taxes		
	Project Specialized	**Project Litespeed**	**Customer 7 - Trans - OR**		**Project Specialized**	**Project Litespeed**	**Customer 7 - Trans - OR**
				Dec-26	(307,153)	(1,282,190)	(310,363)
Jan-27	45,582	199,147	45,163	Jan-27	(355,855)	(1,496,016)	(358,667)
Feb-27	45,582	199,147	45,325	Feb-27	(404,557)	(1,709,842)	(406,971)
Mar-27	45,582	199,147	45,500	Mar-27	(453,259)	(1,923,668)	(455,275)
Apr-27	45,582	199,147	45,587	Apr-27	(501,961)	(2,137,494)	(503,579)
May-27	45,582	199,147	45,587	May-27	(550,663)	(2,351,320)	(551,883)
Jun-27	45,582	199,147	45,587	Jun-27	(599,365)	(2,565,146)	(600,187)
Jul-27	45,582	199,147	45,587	Jul-27	(635,627)	(2,724,353)	(636,152)
Aug-27	45,582	199,147	45,587	Aug-27	(667,919)	(2,866,129)	(668,180)
Sep-27	45,582	199,147	45,587	Sep-27	(692,270)	(2,973,042)	(692,332)
Oct-27	45,582	199,147	45,587	Oct-27	(708,416)	(3,043,930)	(708,346)
Nov-27	45,582	199,147	45,587	Nov-27	(716,621)	(3,079,955)	(716,484)
Dec-27	45,582	199,147	45,587	Dec-27	(716,621)	(3,079,955)	(716,484)
Annual	**546,980**	**2,389,768**	**546,269**	**13 Month Avg**	**(562,330)**	**(2,402,542)**	**(563,454)**

Depreciation Rate *1.770%*

Tab 9 - Dynamic ECD

2020 Protocol Adjustment

	Total	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
2020 Protocol Baseline ECD	(10,164,458)		(11,000,000)		-	835,542		-
	-							-
2020 Protocol Adjustment	**(10,164,458)**	**-**	**(11,000,000)**	**-**	**-**	**835,542**	**-**	**-**

Dynamic ECD Calculation

Embedded Cost Differentials		TOTAL	CA	OR	WA	WY	UT	ID	FERC
Company Owned H	DGP	(97,480,008)		(56,385,324)					
Company Owned H	SG	97,480,008		27,056,136					
Mid-C Contract	MC	1,932,604		1,932,604					
Mid-C Contract	SG	(1,932,604)		(536,405)					
Total Non-Levelized ECD		-	-	(27,932,990)	-	-	-	-	-
		-	-	-	-	-	-	-	-
	DGP	100%	2.889%	57.843%	15.287%	23.981%	0.000%	0.000%	0.000%
	SG	100%	1.386%	27.756%	7.336%	44.587%	5.627%	13.305%	0.004%
	MC	100%	0.000%	100.000%	0.000%	0.000%	0.000%	0.000%	0.000%

OREGON
ANNUAL EMBEDDED COSTS
Twelve Months Ending December 31, 2027
13-MONTH AVERAGE

Company Owned Hydro - West

Account	Description	Amount	Mwh	$/Mwh	Differential
535 - 545	Hydro Operation & Maintenance Expense	16,116,127			
403HP	Hydro Depreciation Expense	31,451,236			
404IP / 404HP	Hydro Relicensing Amortization	2,997,707			
	Total West Hydro Operating Expense	**50,565,071**			
330 - 336	Hydro Electric Plant in Service	1,067,602,028			
302 & 182M	Hydro Relicensing	103,455,075			
108HP	Hydro Accumulated Depreciation Reserve	(415,929,560)			
111IP	Hydro Relicensing Accumulated Reserve	(56,588,688)			
154	Materials and Supplies	0			
	West Hydro Net Rate Base	**698,538,854**			
	Pre-tax Return	9.14%			
	Rate Base Revenue Requirement	**63,820,031**			
	Annual Embedded Cost				
	West Hydro-Electric Resources	**114,385,102**	2,395,873	47.74	(97,480,008)

Mid C Contracts

Account	Description	Amount	Mwh	$/Mwh	Differential
555	Annual Mid-C Contracts Costs	98,130,464	923,712	106.23	16,447,393
	Grant Reasonable Portion	(14,514,790)			(14,514,790)
		83,615,675			1,932,604

Qualified Facilities

Account	Description	Amount	Mwh	$/Mwh	Differential
555	Utah Annual Qualified Facilities Costs				
555	Oregon Annual Qualified Facilities Costs				
555	Idaho Annual Qualified Facilities Costs				
555	WYU Annual Qualified Facilities Costs				
555	WYP Annual Qualified Facilities Costs				
555	California Annual Qualified Facilities Costs				
555	Washington Annual Qualified Facilities Costs				
	Total Qualified Facilities Costs	-	-		-

All Other Generation Resources
(Excl. West Hydro, Mid C, and QF)

Account	Description	Amount	Mwh	$/Mwh	
500 - 514	Steam Operation & Maintenance Expense	930,574,983			
535 - 545	East Hydro Operation & Maintenance Expense	115,802			
546 - 554	Other Generation Operation & Maintenance Expense	53,560,985			
555	Other Purchased Power Contracts	0			
40910	Production Tax Credit	0			
4118	SO2 Emission Allowances	(41)			
456	James River / Little Mountain Offset	0			
456	REC Revenues	0			
403SP	Steam Depreciation Expense	705,611,231			
403HP	East Hydro Depreciation Expense	10,812,805			
403OP	Other Generation Depreciation Expense	13,358,583			
403MP	Mining Depreciation Expense	0			
404IP	East Hydro Relicensing Amortization	255,549			
406	Amortization of Plant Acquisition Costs	0			
	Total All Other Operating Expenses	**1,714,289,897**			
310 - 316	Steam Electric Plant in Service	6,530,039,955			
330 - 336	East Hydro Electric Plant in Service	245,358,306			
302 & 186M	East Hydro Relicensing	10,195,370			
340 - 346	Other Electric Plant in Service	279,188,476			
399	Mining	39,748,016			
108SP	Steam Accumulated Depreciation Reserve	(4,990,193,089)			
108OP	Other Generation Accumulated Depreciation Reserve	(181,066,776)			
108MP	Other Accumulated Depreciation Reserve	0			
108HP	East Hydro Accumulated Depreciation Reserve	(140,832,124)			
111IP	East Hydro Relicensing Accumulated Reserve	(7,576,590)			
114	Electric Plant Acquisition Adjustment	141,186,242			
115	Accumulated Provision Acquisition Adjustment	(141,186,242)			
151	Fuel Stock	262,260,614			
253.16 - 253.19	Joint Owner WC Deposit	(12,243,929)			
253.98	SO2 Emission Allowances	0			
154	Materials & Supplies	103,056,388			
154	East Hydro Materials & Supplies				
	Total Net Rate Base	**2,137,934,618**			
	Pre-tax Return	9.14%			
	Rate Base Revenue Requirement	**195,326,363**			
	Annual Embedded Cost				
	All Other Generation Resources	**1,909,616,260**	21,594,864	88.43	
	Total Annual Embedded Costs	**2,107,617,036**	**24,914,449**	**84.59**	

Oregon General Rate Case - December 2027
Twelve Months Ending December 31, 2027
2020 Protocol Inputs
13 MONTH AVERAGE BALANCE

Code	Indicator	FERC Account	Unadjusted	2020 Pro ECD Adjustments	Total To ECD Calc
151	151SE	151	262,260,614	-	262,260,614
154	154SE	154	-	-	-
154	154SG	154	103,056,388	-	103,056,388
114	114SG	114	141,186,242	-	141,186,242
115	115SG	115	(141,186,242)	-	(141,186,242)
310 - 316	310SG	310	50,518,330	-	50,518,330
310 - 316	311SG	311	1,020,528,602	-	1,020,528,602
310 - 316	312SG	312	4,094,020,247	54,953,430	4,148,973,677
310 - 316	314SG	314	856,816,055	-	856,816,055
310 - 316	315SG	315	420,893,716	-	420,893,716
310 - 316	316SG	316	32,309,575	-	32,309,575
340 - 346	340OR	340	-	-	-
340 - 346	340SG	340	796,929	-	796,929
340 - 346	341SG-W	341	-	-	-
340 - 346	343SG-W	343	-	-	-
340 - 346	344SG-W	344	-	-	-
340 - 346	345SG-W	345	-	-	-
340 - 346	346SG-W	346	-	-	-
340 - 346	341SG	341	17,194,287	-	17,194,287
340 - 346	342SG	342	3,008,761	-	3,008,761
340 - 346	343SG	343	181,215,819	-	181,215,819
340 - 346	344SG	344	64,003,827	-	64,003,827
340 - 346	345SG	345	12,678,410	-	12,678,410
340 - 346	346SG	346	290,442	-	290,442
406	406SG	406	-	-	-
456	456SG	456	-	-	-
500 - 514	500SG	500	14,631,938	-	14,631,938
500 - 514	501SE	501	22,518,322	(19,915,234)	2,603,088
500 - 514	502SG	502	75,898,623	-	75,898,623
500 - 514	505SG	505	717,972	-	717,972
500 - 514	506SG	506	34,329,316	(1,604,762)	32,724,553
500 - 514	507SG	507	(215,297)	-	(215,297)
500 - 514	510SG	510	4,694,443	25,987,093	30,681,536
500 - 514	511SG	511	22,400,683	-	22,400,683
500 - 514	512SG	512	81,757,966	-	81,757,966
500 - 514	513SG	513	34,688,166	-	34,688,166
500 - 514	514SG	514	11,093,598	-	11,093,598
546 - 554	546SG	546	-	-	-
546 - 554	548SG	548	9,733,358	-	9,733,358
546 - 554	549S	549	-	-	-
546 - 554	549SG	550	1,619,271	-	1,619,271
546 - 554	550S	550	-	-	-
546 - 554	550SG	550	39,046	-	39,046
546-554	551SG	551	-	-	-
546 - 554	552SG	552	117,546	-	117,546
546 - 554	553SG	553	298,063	1,054,950	1,353,012
546 - 554	554SG	554	128,767	-	128,767
108OP	108OPSG	108OP	(181,066,776)	-	(181,066,776)

Oregon General Rate Case - December 2027
Twelve Months Ending December 31, 2027
2020 Protocol Inputs
13 MONTH AVERAGE BALANCE

Code	Indicator	FERC Account	Unadjusted	2020 Pro ECD Adjustments	Total To ECD Calc
108OP	108OPSG-W	108OP	-	-	-
108SP	108SPSG	108SP	(4,086,102,183)	(904,090,906)	(4,990,193,089)
403OP	403OPSG	403OP	13,358,583	-	13,358,583
403OP	403OPSG-W	403OP	-	-	-
403SP	403SPSG	403SP	323,607,282	382,003,949	705,611,231
500 - 514	501NPCIDU	501NPC	-	-	-
500 - 514	501NPCSE	501NPC	-	-	-
500 - 514	501NPCWYP	501NPC	-	-	-
500 - 514	501S	501NPC	-	-	-
500 - 514	503NPCSE	503NPC	-	-	-
546 - 554	547NPCSE	547NPC	-	-	-
340 - 346	OPSG	OP	-	-	-
310 - 316	SPSG	SP	-	-	-
			3,503,840,688	**(461,611,481)**	**3,042,229,208**

Oregon General Rate Case - December 2027
Twelve Months Ending December 31, 2027
2020P NPC Summary

Net Power Cost Summary

	NPC $	NPC MWh	
Hermiston Purchase	0	0	
BPA Peak Purchase	0	0	
Georgia-Pacific Camas	0	0	
555 Total	**0**	**0**	Purchase Power Contracts
Naughton 3 Gas	0	0	
Cholla	0	0	
Colstrip	24,719,615	899,052	
Craig	7,640,546	250,281	
Dave Johnston	64,744,500	4,495,872	
Gadsby	27,671,011	373,613	
Hayden	12,379,971	477,111	
Hunter	198,404,834	4,736,645	
Huntington	160,214,578	4,016,794	
Jim Bridger	96,851,776	3,209,004	
Naughton	0	0	
Wyodak	25,421,441	1,327,635	
Ramp Loss n/a		n/a	
501 NPC Total	**618,048,271**	**19,786,007**	Coal
Items not in NPC Report			
Loc 1 & 902 **n/a**			
501 Total n/a			
Little Mountain	0	0	
Hermiston	31,127,920	1,336,088	
Gadsby CT	9,442,065	96,480	
547 Total	**40,569,985**	**1,432,567**	Natural Gas
Blundell	3,859,157	177,568	Pre 70%
Blundell Bottoming Cycle (U2)	1,684,729	77,518	Post 30%
Total Blundell (503 Total)	**5,543,887**	**255,085**	Other
	-		
East Hydro n/a		198,722	
Other MWh	**0**	**198,722**	
Total Pre-2005 NPC Components	**662,477,413**	**21,594,864**	

Tab 10 - 2020 Protocol Factors

Oregon General Rate Case
Pro Forma Factors December 2027
2020 Protocol Factors

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2027

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Situs	S		-	-	-	-	-	-	-	-	-	Situs
System Generation	SG		1.3862%	27.7556%	7.3356%	44.5867%	5.6272%	13.3046%	0.0041%	0.0000%	0.0000%	Pg 10.13
System Generation (Pac. Power Costs on SG)	SG-P		1.3862%	27.7556%	7.3356%	44.5867%	5.6272%	13.3046%	0.0041%	0.0000%	0.0000%	Pg 10.13
System Generation (R.M.P. Costs on SG)	SG-U		1.3862%	27.7556%	7.3356%	44.5867%	5.6272%	13.3046%	0.0041%	0.0000%	0.0000%	Pg 10.13
System Generation (Wind Plant on SG)	SG-W		1.3862%	27.7556%	7.3356%	44.5867%	5.6272%	13.3046%	0.0041%	0.0000%	0.0000%	Pg 10.13
Divisional Generation - Pac. Power	DGP		2.8889%	57.8430%	15.2875%	0.0000%	0.0000%	23.9806%	0.0000%	0.0000%	0.0000%	Pg 10.13
Divisional Generation - R.M.P.	DGU		0.0000%	0.0000%	0.0000%	85.7179%	10.8182%	3.4560%	0.0078%	0.0000%	0.0000%	Pg 10.13
System Capacity	SC		1.4316%	28.0665%	7.5448%	44.4975%	5.4967%	12.9592%	0.0038%	0.0000%	0.0000%	Pg 10.13
System Energy	SE		1.2502%	26.8228%	6.7081%	44.8544%	6.0186%	14.3409%	0.0049%	0.0000%	0.0000%	Pg 10.13
System Overhead	SO		3.0320%	27.9089%	7.0188%	44.5111%	5.3767%	12.1498%	0.0028%	0.0000%	0.0000%	Pg 10.7
Gross Plant-System	GPS		3.2453%	27.9296%	6.9792%	44.4955%	5.3449%	12.0029%	0.0026%	0.0000%	0.0000%	Pg 10.6
System Net Plant	SNP		4.0165%	26.5566%	6.4181%	46.3336%	5.2834%	11.3893%	0.0025%	0.0000%	0.0000%	Pg 10.7
Division Net Plant Distribution	SNPD		8.0150%	25.5781%	5.0180%	48.7534%	4.5507%	8.0849%	0.0000%	0.0000%	0.0000%	Pg 10.5
Customer - System	CN		2.1946%	30.1397%	6.8696%	49.5925%	4.2855%	6.9181%	0.0000%	0.0000%	0.0000%	Pg 10.8
CIAC	CIAC		8.0150%	25.5781%	5.0180%	48.7534%	4.5507%	8.0849%	0.0000%	0.0000%	0.0000%	Pg 10.8
Bad Debt Expense	BADDEBT		5.3073%	42.7206%	14.6725%	28.3688%	1.9526%	6.9782%	0.0000%	0.0000%	0.0000%	Pg 10.7
Accumulated Investment Tax Credit 1984	ITC84		3.2870%	70.9760%	14.1800%	0.0000%	0.0000%	10.9460%	0.0000%	0.0000%	0.6110%	Fixed
Accumulated Investment Tax Credit 1985	ITC85		5.4200%	67.6900%	13.3600%	0.0000%	0.0000%	11.6100%	0.0000%	0.0000%	1.9200%	Fixed
Accumulated Investment Tax Credit 1986	ITC86		4.7890%	64.6080%	13.1260%	0.0000%	0.0000%	15.5000%	0.0000%	0.0000%	1.9770%	Fixed
Accumulated Investment Tax Credit 1988	ITC88		4.2700%	61.2000%	14.9600%	0.0000%	0.0000%	16.7100%	0.0000%	0.0000%	2.8600%	Fixed
Accumulated Investment Tax Credit 1989	ITC89		4.8806%	56.3558%	15.2688%	0.0000%	0.0000%	20.6776%	0.0000%	0.0000%	2.8172%	Fixed
Accumulated Investment Tax Credit 1990	ITC90		1.5047%	15.9356%	3.9132%	46.9355%	13.9815%	17.3435%	0.0000%	0.0000%	0.3860%	Fixed
Other Electric	OTHER		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	Situs
Non-Utility	NUTIL		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	Situs
System Net Steam Plant	SNPPS		1.3744%	31.3424%	6.6313%	42.4549%	5.5009%	12.6915%	0.0046%	0.0000%	0.0000%	Pg 10.3
System Net Transmission Plant	SNPT		1.3862%	27.7556%	7.3356%	44.5867%	5.6272%	13.3046%	0.0041%	0.0000%	0.0000%	Pg 10.4
System Net Production Plant	SNPP		1.4742%	24.4714%	7.5214%	46.6470%	5.9502%	13.9312%	0.0046%	0.0000%	0.0000%	Pg 10.4
System Net Hydro Plant	SNPPH		1.3862%	27.7556%	7.3356%	44.5867%	5.6272%	13.3046%	0.0041%	0.0000%	0.0000%	Pg 10.3
System Net Other Production Plant	SNPPO		1.3862%	27.7556%	7.3356%	44.5867%	5.6272%	13.3046%	0.0041%	0.0000%	0.0000%	Pg 10.4
System Net General Plant	SNPG		2.9188%	28.1056%	6.1669%	42.4246%	6.3672%	14.0153%	0.0017%	0.0000%	0.0000%	Pg 10.5
System Net Intangible Plant	SNPI		1.4804%	26.8382%	7.5675%	42.9725%	6.8116%	14.3262%	0.0036%	0.0000%	0.0000%	Pg 10.6
Trojan Plant Allocator	TROJP		1.3656%	27.6139%	7.2403%	44.6274%	5.6866%	13.4620%	0.0042%	0.0000%	0.0000%	Pg 10.9
Trojan Decommissioning Allocator	TROJD		1.3619%	27.5889%	7.2234%	44.6346%	5.6971%	13.4898%	0.0042%	0.0000%	0.0000%	Pg 10.9
DIT Balance	DITBAL		2.1767%	25.7790%	6.8786%	46.7390%	5.6154%	12.8287%	0.0033%	-0.0207%	0.0000%	Pg 10.7
Tax Depreciation	TAXDEPR		3.7906%	27.7100%	6.5996%	45.2084%	5.2476%	11.4332%	0.0028%	0.0078%	0.0000%	Pg 10.10
SCHMAT Depreciation Expense	SCHMDEXP		3.3448%	27.2462%	7.0642%	44.7453%	5.3665%	12.2302%	0.0027%	0.0000%	0.0000%	Pg 10.10
System Generation Cholla Transaction	SGCT		1.3863%	27.7567%	7.3359%	44.5885%	5.6274%	13.3052%	0.0000%	0.0000%	0.0000%	Pg 10.2

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2027

DESCRIPTION **CALCULATION OF INTERNAL FACTORS** **Pro Forma Factors December 31, 2027**	**2020 PROTOCOL FACTOR**		**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC-UPL**	**OTHER**	**NON-UTILITY**	**Page Ref.**
DESCRIPTION OF FACTOR		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
STEAM :												
STEAM PRODUCTION PLANT												
	S	0	0	0	0	0	0	0	0	0	0	
	SG	7,147,366,363	99,078,854	1,983,792,608	524,302,523	3,186,777,028	402,195,082	950,929,422	290,846	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
		7,147,366,363	99,078,854	1,983,792,608	524,302,523	3,186,777,028	402,195,082	950,929,422	290,846	0	0	
LESS ACCUMULATED DEPRECIATION												
	S	(125,633,865)	(1,856,680)	0	(16,063,271)	(76,741,331)	(8,297,223)	(22,675,360)	0	0	0	
	SG	(6,049,553,958)	(83,860,662)	(1,679,088,466)	(443,771,348)	(2,697,298,362)	(340,419,215)	(804,869,732)	(246,173)	0	0	
	SG-W	0	0	0	0	0	0	0	0	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
		(6,175,187,822)	(85,717,342)	(1,679,088,466)	(459,834,619)	(2,774,039,692)	(348,716,439)	(827,545,092)	(246,173)	0	0	
TOTAL NET STEAM PLANT		972,178,541	13,361,513	304,704,142	64,467,904	412,737,336	53,478,643	123,384,330	44,673	0	0	
SNPPS												
SYSTEM NET PLANT PRODUCTION STEAM		100.0000%	1.3744%	31.3424%	6.6313%	42.4549%	5.5009%	12.6915%	0.0046%	0.0000%	0.0000%	
HYDRO:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
HYDRO PRODUCTION PLANT												
	S	0	0	0	0	0	0	0	0	0	0	
	SG	1,325,006,862	18,367,627	367,763,269	97,197,262	590,777,248	74,560,505	176,287,033	53,918	0	0	
		1,325,006,862	18,367,627	367,763,269	97,197,262	590,777,248	74,560,505	176,287,033	53,918	0	0	
LESS ACCUMULATED DEPRECIATION (incl hydro amortization)												
	S	0	0	0	0	0	0	0	0	0	0	
	SG	(561,784,935)	(7,787,625)	(155,926,637)	(41,210,321)	(250,481,539)	(31,612,643)	(74,743,311)	(22,861)	0	0	
		(561,784,935)	(7,787,625)	(155,926,637)	(41,210,321)	(250,481,539)	(31,612,643)	(74,743,311)	(22,861)	0	0	
TOTAL NET HYDRO PRODUCTION PLANT		763,221,927	10,580,003	211,836,632	55,986,941	340,295,709	42,947,862	101,543,722	31,058	0	0	
SNPPH												
SYSTEM NET PLANT PRODUCTION HYDRO		100.0000%	1.3862%	27.7556%	7.3356%	44.5867%	5.6272%	13.3046%	0.0041%	0.0000%	0.0000%	

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2027

DESCRIPTION	2020 PROTOCOL FACTOR	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
OTHER:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
OTHER PRODUCTION PLANT (EXCLUDES EXPERIMENTAL)												
	S	0	0	0	0	0	0	0	0	0	0	
	SG	2,118,875,013	29,372,457	588,105,936	155,432,289	944,737,106	119,232,885	281,908,117	86,223	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		2,118,875,013	29,372,457	588,105,936	155,432,289	944,737,106	119,232,885	281,908,117	86,223	0	0	
LESS ACCUMULATED DEPRECIATION												
	S	0	0	0	0	0	0	0	0	0	0	
	SG	(833,460,220)	(11,553,666)	(231,331,674)	(61,139,345)	(371,612,668)	(46,900,296)	(110,888,655)	(33,916)	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		(833,460,220)	(11,553,666)	(231,331,674)	(61,139,345)	(371,612,668)	(46,900,296)	(110,888,655)	(33,916)	0	0	
TOTAL NET OTHER PRODUCTION PLANT		1,285,414,793	17,818,791	356,774,263	94,292,944	573,124,438	72,332,588	171,019,461	52,307	0	0	
SNPPO												
SYSTEM NET PLANT PRODUCTION OTHER		100.0000%	1.3862%	27.7556%	7.3356%	44.5867%	5.6272%	13.3046%	0.0041%	0.0000%	0.0000%	
PRODUCTION:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
TOTAL PRODUCTION PLANT												
	S	0	0	0	0	0	0	0	0	0	0	
	SG	10,591,248,238	146,818,938	2,939,661,813	776,932,074	4,722,291,382	595,988,471	1,409,124,572	430,987	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		10,591,248,238	146,818,938	2,939,661,813	776,932,074	4,722,291,382	595,988,471	1,409,124,572	430,987	0	0	
LESS ACCUMULATED DEPRECIATION												
	S	(275,469,823)	(1,856,680)	(149,702,789)	(16,063,271)	(76,874,500)	(8,297,223)	(22,675,360)	0	0	0	
	SG-P	(8,085,517,387)	(112,083,774)	(2,244,181,816)	(593,121,571)	(3,605,067,903)	(454,986,517)	(1,075,746,784)	(329,022)	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		(8,360,987,210)	(113,940,454)	(2,393,884,605)	(609,184,842)	(3,681,942,402)	(463,283,740)	(1,098,422,144)	(329,022)	0	0	
TOTAL NET PRODUCTION PLANT		2,230,261,028	32,878,484	545,777,208	167,747,232	1,040,348,979	132,704,731	310,702,428	101,965	0	0	
SNPP												
SYSTEM NET PRODUCTION PLANT		100.0000%	1.4742%	24.4714%	7.5214%	46.6470%	5.9502%	13.9312%	0.0046%	0.0000%	0.0000%	
TRANSMISSION:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
TRANSMISSION PLANT												
	SG	12,318,889,382	170,767,998	3,419,178,541	903,664,994	5,492,590,095	693,205,927	1,638,980,537	501,289			
		12,318,889,382	170,767,998	3,419,178,541	903,664,994	5,492,590,095	693,205,927	1,638,980,537	501,289			
LESS ACCUMULATED DEPRECIATION												
	SG	(2,986,638,199)	(41,401,640)	(828,958,596)	(219,087,964)	(1,331,644,345)	(168,063,470)	(397,360,649)	(121,534)			
		(2,986,638,199)	(41,401,640)	(828,958,596)	(219,087,964)	(1,331,644,345)	(168,063,470)	(397,360,649)	(121,534)			
TOTAL NET TRANSMISSION PLANT		9,332,251,183	129,366,358	2,590,219,946	684,577,030	4,160,945,749	525,142,456	1,241,619,888	379,755			
SNPT												
SYSTEM NET PLANT TRANSMISSION		100.0000%	1.3862%	27.7556%	7.3356%	44.5867%	5.6272%	13.3046%	0.0041%			

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
DISTRIBUTION:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
DISTRIBUTION PLANT - PACIFIC POWER	S	5,885,305,272	827,396,454	3,365,009,636	749,000,099	0	0	943,899,083	0			
LESS ACCUMULATED DEPRECIATION	S	(2,288,852,072)	(194,365,011)	(1,344,836,407)	(352,676,756)	0	0	(396,973,898)	0			
		3,596,453,200	633,031,443	2,020,173,229	396,323,343	0	0	546,925,185	0			
DNPDP												
DIVISION NET PLANT DISTRIBUTION PACIFIC POWER		100.0000%	17.6015%	56.1713%	11.0198%	0.0000%	0.0000%	15.2073%	0.0000%			
DISTRIBUTION PLANT - ROCKY MOUNTAIN POWER												
	S	6,019,049,735	0	0	0	5,296,719,195	555,841,103	166,489,437	0			
LESS ACCUMULATED DEPRECIATION												
	S	(1,717,441,717)	0	0	0	(1,446,148,347)	(196,426,924)	(74,866,447)	0			
		4,301,608,017	0	0	0	3,850,570,848	359,414,179	91,622,990	0			
DNPDU												
DIVISION NET PLANT DISTRIBUTION R.M.P.		100.0000%	0.0000%	0.0000%	0.0000%	89.5147%	8.3553%	2.1300%	0.0000%			
TOTAL NET DISTRIBUTION PLANT		7,898,061,218	633,031,443	2,020,173,229	396,323,343	3,850,570,848	359,414,179	638,548,174	0			
DNPD & SNPD												
SYSTEM NET PLANT DISTRIBUTION		100.0000%	8.0150%	25.5781%	5.0180%	48.7534%	4.5507%	8.0849%	0.0000%			
GENERAL:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
GENERAL PLANT												
	S	585,314,105	16,465,606	163,073,744	39,908,484	227,133,136	45,607,810	93,125,325	0			
	SE	2,544,783	31,815	682,582	170,707	1,141,448	153,161	364,945	126			
	SG	108,702,655	1,506,868	30,171,047	7,973,997	48,466,961	6,116,893	14,462,467	4,423			
	SO	980,965,690	29,742,673	273,776,650	68,851,901	436,638,313	52,743,556	119,185,093	27,504			
	CN	237,089,255	5,203,181	71,458,104	16,287,050	117,578,433	10,160,485	16,402,001	0			
	SSGCT	0	0	0	0	0	0	0	0			
	SSGCH	0	0	0	0	0	0	0	0			
	Remove Capital Lease	(28,521,120)	(86,437)	(9,546,920)	(2,726,695)	(9,462,184)	(2,453,402)	(4,245,228)	(254)			
		1,886,095,368	52,863,706	529,615,207	130,465,444	821,496,107	112,328,502	239,294,603	31,799			
LESS ACCUMULATED DEPRECIATION												
	S	(276,174,752)	(7,744,769)	(74,024,077)	(23,817,323)	(108,751,390)	(20,822,882)	(41,014,311)	0			
	DGP	165,454	2,294	45,923	12,137	73,770	9,310	22,013	7			
	DGU	513,009	7,111	142,389	37,632	228,734	28,868	68,254	21			
	SE	(1,561,399)	(19,521)	(418,811)	(104,740)	(700,357)	(93,975)	(223,919)	(77)			
	SG	(60,300,157)	(835,898)	(16,736,655)	(4,423,381)	(26,885,869)	(3,393,198)	(8,022,702)	(2,454)			
	SO	(598,627,520)	(18,150,261)	(167,070,305)	(42,016,396)	(266,455,507)	(32,186,390)	(72,731,878)	(16,784)			
	CN	(222,176,030)	(4,875,894)	(66,963,296)	(15,262,574)	(110,182,595)	(9,521,377)	(15,370,294)	0			
	SSGCT	0	0	0	0	0	0	0	0			
	SSGCH	0	0	0	0	0	0	0	0			
		(1,158,161,395)	(31,616,938)	(325,024,832)	(85,574,644)	(512,673,214)	(65,979,643)	(137,272,837)	(19,287)			
TOTAL NET GENERAL PLANT		727,933,973	21,246,769	204,590,375	44,890,799	308,822,893	46,348,859	102,021,767	12,512			
SNPG												
SYSTEM NET GENERAL PLANT		100.0000%	2.9188%	28.1056%	6.1669%	42.4246%	6.3672%	14.0153%	0.0017%			

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DESCRIPTION	2020 PROTOCOL FACTOR	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
MINING:												
GENERAL MINING PLANT	SE	39,748,016	496,932	10,661,525	2,666,341	17,828,751	2,392,277	5,700,227	1,963			
LESS ACCUMULATED DEPRECIATION	SE	0	0	0	0	0	0	0	0			
		39,748,016	496,932	10,661,525	2,666,341	17,828,751	2,392,277	5,700,227	1,963			
SNPM												
SYSTEM NET PLANT MINING		100.0000%	1.2502%	26.8228%	6.7081%	44.8544%	6.0186%	14.3409%	0.0049%			
INTANGIBLE:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
INTANGIBLE PLANT												
	S	24,001,523	469,320	4,597,089	2,016,070	7,436,155	4,351,609	5,131,280	0			
	SE	0	0	0	0	0	0	0	0			
	CN	(3,178,870)	(69,764)	(958,104)	(218,375)	(1,576,481)	(136,231)	(219,916)	0			
	SG	309,808,102	4,294,649	85,989,019	22,726,297	138,133,306	17,433,456	41,218,768	12,607			
	SO	(13,908,637)	(421,707)	(3,881,746)	(976,218)	(6,190,883)	(747,825)	(1,689,868)	(390)			
	SSGCT	0	0	0	0	0	0	0	0			
	SSGCH	0	0	0	0	0	0	0	0			
		316,722,118	4,272,498	85,746,258	23,547,774	137,802,097	20,901,008	44,440,265	12,217			
LESS ACCUMULATED AMORTIZATION												
	S	(2,120,862)	3,021	(170,171)	5,175	(576,883)	(995,018)	(386,986)	0			
	DGU	18,570	257	5,154	1,362	8,280	1,045	2,471	1			
	SE	0	0	0	0	0	0	0	0			
	CN	3,178,870	69,764	958,104	218,375	1,576,481	136,231	219,916	0			
	SG	(152,266,316)	(2,110,760)	(42,262,391)	(11,169,655)	(67,890,573)	(8,568,298)	(20,258,444)	(6,196)			
	SO	13,908,637	421,707	3,881,746	976,218	6,190,883	747,825	1,689,868	390			
	SSGCT	0	0	0	0	0	0	0	0			
	SSGCH	0	0	0	0	0	0	0	0			
		(137,281,100)	(1,616,010)	(37,587,557)	(9,968,524)	(60,691,813)	(8,678,215)	(18,733,175)	(5,805)			
TOTAL NET INTANGIBLE PLANT		179,441,017	2,656,488	48,158,701	13,579,250	77,110,284	12,222,794	25,707,090	6,412			
SNPI												
SYSTEM NET INTANGIBLE PLANT		100.0000%	1.4804%	26.8382%	7.5675%	42.9725%	6.8116%	14.3262%	0.0036%			
GROSS PLANT:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
PRODUCTION PLANT		10,591,248,238	146,818,938	2,939,661,813	776,932,074	4,722,291,382	595,988,471	430,987	430,987	0	0	
TRANSMISSION PLANT		12,318,889,382	170,767,998	3,419,178,541	903,664,994	5,492,590,095	693,205,927	1,638,980,537	501,289	0	0	
DISTRIBUTION PLANT		11,904,355,007	827,396,454	3,365,009,636	749,000,099	5,296,719,195	555,841,103	1,110,388,520	0	0	0	
GENERAL PLANT		1,925,843,384	53,360,638	540,276,733	133,131,785	839,324,857	114,720,779	244,994,830	33,762	0	0	
INTANGIBLE PLANT		316,722,118	4,272,498	85,746,258	23,547,774	137,802,097	20,901,008	44,440,265	12,217	0	0	
TOTAL GROSS PLANT		37,057,058,128	1,202,616,527	10,349,872,982	2,586,276,726	16,488,727,626	1,980,657,289	3,039,235,139	978,255	0	0	
GPS												
GROSS PLANT-SYSTEM FACTOR		100.0000%	3.2453%	27.9296%	6.9792%	44.4955%	5.3449%	12.0029%	0.0026%	0.0000%	0.0000%	
ACCUMULATED DEPRECIATION AND AMORTIZATION												
PRODUCTION PLANT		(8,360,987,210)	(113,940,454)	(2,393,884,605)	(609,184,842)	(3,681,942,402)	(463,283,740)	(1,098,422,144)	(329,022)	0	0	
TRANSMISSION PLANT		(2,986,638,199)	(41,401,640)	(828,958,596)	(219,087,964)	(1,331,644,345)	(168,063,470)	(397,360,649)	(121,534)	0	0	
DISTRIBUTION PLANT		(4,006,293,789)	(194,365,011)	(1,344,836,407)	(352,676,756)	(1,446,148,347)	(196,426,924)	(471,840,345)	0	0	0	
GENERAL PLANT		(1,158,161,395)	(31,616,938)	(325,024,832)	(85,574,644)	(512,673,214)	(65,979,643)	(137,272,837)	(19,287)	0	0	
INTANGIBLE PLANT		(137,281,100)	(1,616,010)	(37,587,557)	(9,968,524)	(60,691,813)	(8,678,215)	(18,733,175)	(5,805)	0	0	
		(16,649,361,693)	(382,940,053)	(4,930,291,997)	(1,276,492,731)	(7,033,100,122)	(902,431,992)	(2,123,629,150)	(475,649)	0	0	
NET PLANT		20,407,696,435	819,676,474	5,419,580,984	1,309,783,995	9,455,627,504	1,078,225,297	915,605,989	502,606	0	0	

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
SNP												
SYSTEM NET PLANT FACTOR (SNP)		100.0000%	4.0165%	26.5566%	6.4181%	46.3336%	5.2834%	11.3893%	0.0025%	0.0000%	0.0000%	
NON-UTILITY RELATED INTEREST PERCENTAGE		0.0000%										
INT												
INTEREST FACTOR SNP - NON-UTILITY		100.0000%	4.0165%	26.5566%	6.4181%	46.3336%	5.2834%	11.3893%	0.0025%	0.0000%	0.0000%	
TOTAL GROSS PLANT (LESS SO FACTOR)		41,049,577,316	1,244,614,554	11,456,482,005	2,881,182,748	18,271,605,600	2,207,111,517	4,987,429,967	1,150,925	0	0	
SO												
SYSTEM OVERHEAD FACTOR (SO)		100.0000%	3.0320%	27.9089%	7.0188%	44.5111%	5.3767%	12.1498%	0.0028%	0.0000%	0.0000%	

IBT

INCOME BEFORE TAXES	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	OTHER	NON-UTILITY
INCOME BEFORE STATE TAXES	2,468,029,728	15,414,153	102,396,587	232,152,178	1,355,746,753	207,524,505	427,680,058	16,849,090	110,266,404	0
Interest Synchronization	(53,623,316)	0	0	0	0	0	0	0	(53,623,316)	0
	2,414,406,411	15,414,153	102,396,587	232,152,178	1,355,746,753	207,524,505	427,680,058	16,849,090	56,643,088	0
INCOME BEFORE TAXES (FACTOR)	100.0000%	0.6384%	4.2411%	9.6153%	56.1524%	8.5953%	17.7137%	0.6979%	2.3460%	0.0000%

See Calculation of EXCTAX

DITBAL:		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	OTHER	NON-UTILITY
Jurisdictional ADIT - 12/31/2027 - TOTAL		3,482,721,100	75,808,051	897,811,250	239,562,854	1,627,790,231	195,567,858	446,787,868	113,691	(720,703)	0
Jurisdictional ADIT - 12/31/2027 - CA	S	34,504,855	34,504,855	0	0	0	0				
Jurisdictional ADIT - 12/31/2027 - ID	S	36,492,187	0	0	0	0	36,492,187	0	0	0	0
Jurisdictional ADIT - 12/31/2027 - OTHER	S	(720,703)	0	0	0	0	0	0	0	(720,703)	0
Jurisdictional ADIT - 12/31/2027 - OR	S	111,463,388	0	111,463,388	0	0	0	0	0	0	0
Jurisdictional ADIT - 12/31/2027 - SG	SG	2,156,132,048	29,888,924	598,446,841	158,165,318	961,348,800	121,329,405	286,865,021	87,739	0	0
Jurisdictional ADIT - 12/31/2027 - SG-CAGE	SG	428,707,273	5,942,864	118,990,167	31,448,270	191,146,559	24,124,125	57,037,843	17,445	0	0
Jurisdictional ADIT - 12/31/2027 - SG-CAGW	SG	123,686,007	1,714,571	34,329,762	9,073,116	55,147,547	6,960,033	16,455,944	5,033	0	0
Jurisdictional ADIT - 12/31/2027 - SO	SO	123,907,078	3,756,837	34,581,092	8,696,775	55,152,365	6,662,109	15,054,427	3,474	0	0
Jurisdictional ADIT - 12/31/2027 - UT	UT	364,994,959	0	0	0	364,994,959	0	0	0	0	0
Jurisdictional ADIT - 12/31/2027 - WA	WA	32,179,376	0	0	32,179,376	0	0	0	0	0	0
Jurisdictional ADIT - 12/31/2027 - WY	WY	71,374,632	0	0	0	0	0	71,374,632	0	0	0
Jurisdictional ADIT - 12/31/2027 - TOTAL		3,482,721,100	75,808,051	897,811,250	239,562,854	1,627,790,231	195,567,858	446,787,868	113,691	(720,703)	0
Total PacifiCorp		3,482,721,100	75,808,051	897,811,250	239,562,854	1,627,790,231	195,567,858	446,787,868	113,691	(720,703)	0
Percentage of Total (DITBAL)		100.0000%	2.1767%	25.7790%	6.8786%	46.7390%	5.6154%	12.8287%	0.0033%	-0.0207%	0.0000%

BADDEBT

	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	OTHER	NUTIL
Account 904 Balance	26,152,291	1,387,989	11,172,422	3,837,183	7,419,092	510,637	1,824,968	0	0	0
Bad Debts Expense Allocation Factor - BADDEBT	100.0000%	5.3073%	42.7206%	14.6725%	28.3688%	1.9526%	6.9782%	0.0000%	0.0000%	0.0000%

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Customer Factors		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Total Electric Customers		2,183,651	47,923	658,147	150,008	1,082,927	93,581	151,067	0	0	0	
CN												
Customer System factor - CN		100.0000%	2.1946%	30.1397%	6.8696%	49.5925%	4.2855%	6.9181%	0.0000%	0.0000%	0.0000%	
Pacific Power Customers		989,840	47,923	658,147	150,008	0	0	133,762	0	0	0	
CNP												
Customer Service Pacific Power factor - CNP		100.0000%	4.8415%	66.4903%	15.1548%	0.0000%	0.0000%	13.5135%	0.0000%	0.0000%	0.0000%	
Rocky Mountain Power Customers		1,193,811	0	0	0	1,082,927	93,581	17,304	0	0	0	
CNU												
Customer Service R.M.P. factor - CNU		100.0000%	0.0000%	0.0000%	0.0000%	90.7117%	7.8388%	1.4495%	0.0000%	0.0000%	0.0000%	
CIAC		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
TOTAL NET DISTRIBUTION PLANT		7,898,061,218	633,031,443	2,020,173,229	396,323,343	3,850,570,848	359,414,179	638,548,174	0	0	0	
CIAC FACTOR: Same as (SNPD Factor)		100.0000%	8.0150%	25.5781%	5.0180%	48.7534%	4.5507%	8.0849%	0.0000%	0.0000%	0.0000%	
EXCTAX												
Excise Tax (Superfund)		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Total Taxable Income		2,346,751,248	14,714,350	97,254,998	221,612,469	1,294,195,850	198,102,892	408,263,384	16,084,142	96,523,163	0	
Less Other Electric Items:												
419 OTH		0	0	0	0	0	0	0	0	0	0	
432 OTH		0	0	0	0	0	0	0	0	0	0	
40910 OTH		0	0	0	0	0	0	0	0	0	0	
SCHMDT OTH		0	0	0	0	0	0	0	0	0	0	
SCHMDT (Steam) OTH												
Total Taxable Income Excluding Other		2,346,751,248	14,714,350	97,254,998	221,612,469	1,294,195,850	198,102,892	408,263,384	16,084,142	96,523,163	0	
Excise Tax (Superfund) Factor - EXCTAX		100.0000%	0.6270%	4.1442%	9.4434%	55.1484%	8.4416%	17.3970%	0.6854%	4.1131%	0.0000%	
Trojan Allocators		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Premerger												
Dec 1991 Plant		16,918,976										
Dec 1992 Plant		17,094,202										
Average	SG	17,006,589	235,750	4,720,277	1,247,536	7,582,682	956,991	2,262,661	692	0	0	
Dec 1991 Reserve		(7,851,432)										
Dec 1992 Reserve		(8,434,030)										
Average	SG	(8,142,731)	(112,877)	(2,260,062)	(597,319)	(3,630,578)	(458,206)	(1,083,359)	(331)	0	0	
Postmerger												
Dec 1991 Plant		4,284,960										
Dec 1992 Plant		3,485,613										
Average	SG	3,885,287	53,859	1,078,384	285,009	1,732,322	218,632	516,922	158	0	0	
Dec 1991 Reserve		(129,394)										
Dec 1992 Reserve		(240,609)										
Average	SG	(185,002)	(2,565)	(51,348)	(13,571)	(82,486)	(10,410)	(24,614)	0	0	0	
Net Plant		12,564,143	174,168	3,487,250	921,656	5,601,941	707,007	1,671,611	511	0	0	

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2027

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Division Net Plant Nuclear Pacific Power	**DNPPNP**	100.0000%	1.3862%	27.7556%	7.3356%	44.5867%	5.6272%	13.3046%	0.0041%	0.0000%	0.0000%	
Division Net Plant Nuclear Rocky Mountain Power	**DNPPNP**	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.00%	0.00%	0.00%	0.00%	
System Net Nuclear Plant	**SNNP**	100.0000%	1.3862%	27.7556%	7.3356%	44.5867%	5.6272%	13.3046%	0.0041%	0.0000%	0.0000%	

Account 182.22			**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**
Pre-merger	(101)	SG	17,094,202	236,965	4,744,594	1,253,963	7,621,746	961,921	2,274,317	696	0	0
	(108)	SG	(8,434,030)	(116,915)	(2,340,913)	(618,687)	(3,760,458)	(474,598)	(1,122,115)	(343)	0	0
Post-merger	(101)	SG	3,485,613	48,319	967,452	255,691	1,554,121	196,142	463,747	142	0	0
	(108)	SG	(240,609)	(3,335)	(66,782)	(17,650)	(107,280)	(13,539)	(32,012)	(10)	0	0
	(107)	SG	1,778,549	24,655	493,646	130,467	792,997	100,082	236,629	72	0	0
	(120)	SE	1,975,759	24,701	529,954	132,536	886,216	118,913	283,342	98	0	0
	(228)	SG	7,220,849	100,097	2,004,188	529,693	3,219,541	406,330	960,706	294	0	0
	(228)	SG	1,472,376	20,411	408,666	108,008	656,484	82,853	195,894	60	0	0
	(228)	SNNP	3,531,000	48,948	980,049	259,020	1,574,357	198,696	469,786	144	0	0
	(228)	SE	1,743,025	21,791	467,528	116,924	781,824	104,906	249,966	86	0	0
Total Acct 182.22			29,626,734	405,636	8,188,382	2,149,965	13,219,548	1,681,706	3,980,260	1,238	0	0
Revised Study	(228)	SNNP	112,680	1,562	31,275	8,266	50,240	6,341	14,992	5	0	0
	(228)	SE	941,950	11,776	252,657	63,187	422,506	56,692	135,084	47	0	0
December 1993 Adj.			1,054,630	13,338	283,932	71,453	472,747	63,033	150,076	51	0	0
Adjusted Acct 182.22			30,681,364	418,974	8,472,314	2,221,418	13,692,295	1,744,739	4,130,336	1,289	0	0
TROJP			100.0000%	1.3656%	27.6139%	7.2403%	44.6274%	5.6866%	13.4620%	0	0	0
Trojan Plant Allocator												

Account 228.42		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**
Plant - Premerger	SG	7,220,849	100,097	2,004,188	529,693	3,219,541	406,330	960,706	294	0	0
- Postmerger	SG	1,472,376	20,411	408,666	108,008	656,484	82,853	195,894	60	0	0
Storage Facility	SE	1,743,025	21,791	467,528	116,924	781,824	104,906	249,966	86	0	0
Transition Costs	SNNP	3,531,000	48,948	980,049	259,020	1,574,357	198,696	469,786	144	0	0
Total Acct 228.42		13,967,250	191,247	3,860,432	1,013,645	6,232,206	792,785	1,876,351	584	0	0
Transition Costs	SNNP	112,680	1,562	31,275	8,266	50,240	6,341	14,992	5	0	0
Storage Facility	SE	941,950	11,776	252,657	63,187	422,506	56,692	135,084	47	0	0
December 1993 Adj.		1,054,630	13,338	283,932	71,453	472,747	63,033	150,076	51	0	0
Adjusted Acct 228.42		15,021,880	204,585	4,144,364	1,085,098	6,704,953	855,818	2,026,427	635	0	0
TROJD		100.0000%	1.3619%	27.5889%	7.2234%	44.6346%	5.6971%	13.4898%	0.0042%	0.0000%	0.0000%
Trojan Decommissioning Allocator											

SCHMA		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**
Amortization Expense :											
Amortization of Limited Term Plant	Acct 404	9,129,044	122,390	2,523,544	746,071	4,012,588	494,453	1,229,641	357	0	0
Amortization of Other Electric Plant	Acct 405	0	0	0	0	0	0	0	0	0	0
Amortization of Plant Acquisitions	Acct 406	376,987	1,045	20,914	5,527	335,232	4,240	10,025	3	0	0
Amort of Prop. Losses, Unrecovered Plant, etc.	Acct 407	12,915,695	4,917,273	(2,839,665)	1,048,058	8,083,735	893,486	6,695,022	581	(5,882,796)	0
Total Amortization Expense :		22,421,726	5,040,707	(295,207)	1,799,656	12,431,555	1,392,179	7,934,689	942	(5,882,796)	0
Schedule M Amortization Factor		100.0000%	22.4814%	-1.3166%	8.0264%	55.4442%	6.2091%	35.3884%	0.0042%	-26.2370%	0.0000%

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2027

DESCRIPTION SCHMD	2020 PROTOCOL FACTOR	TOTAL	California California	Oregon Oregon	Washington Washington	Utah Utah	Idaho Idaho	Wyoming Wyoming	FERC-UPL FERC	OTHER OTHER	NON-UTILITY NON-UTILITY	Page Ref.
Depreciation Expense :												
Steam	Acct 403.1	314,798,531	4,363,828	87,374,141	23,092,375	140,358,375	17,714,276	41,882,726	12,810	0	0	
Nuclear	Acct 403.2	0	0	0	0	0	0	0	0	0	0	
Hydro	Acct 403.3	46,427,073	643,585	12,886,101	3,405,706	20,700,314	2,612,534	6,176,942	1,889	0	0	
Other	Acct 403.4	75,499,184	1,046,591	20,955,232	5,538,321	33,662,618	4,248,474	10,044,874	3,072	0	0	
Transmission	Acct 403.5	217,813,885	3,019,399	60,455,495	15,977,965	97,116,091	12,256,777	28,979,294	8,863	0	0	
Distribution	Acct 403.6	303,235,403	23,387,033	78,514,380	19,726,003	136,788,110	14,517,912	30,301,966	0	0	0	
General	Acct 403.7&8	85,339,221	2,430,095	24,023,768	5,947,290	38,118,592	4,628,193	10,189,260	2,023	0	0	
Mining	Acct 403.9	0	0	0	0	0	0	0	0	0	0	
Experimental	Acct 403.4	0	0	0	0	0	0	0	0	0	0	
Postmerger Hydro Step I Adjustment		0	0	0	0	0	0	0	0	0	0	
Total Depreciation Expense :		1,043,113,296	34,890,532	284,209,118	73,687,660	466,744,100	55,978,166	127,575,062	28,658	0	0	
Schedule M Depreciation Factor		100.0000%	3.3448%	27.2462%	7.0642%	44.7453%	5.3665%	12.2302%	0.0027%	0.0000%	0.0000%	
TAXDEPR		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Jurisdictional Tax Depreciation - 12/31/2027 - TOTAL		(1,452,147,228)	(55,044,741)	(402,389,625)	(95,836,313)	(656,492,395)	(76,203,523)	(166,026,338)	(40,609)	(113,685)	0	
									0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - CA	S	(38,739,111)	(38,739,111)	0	0	0	0	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - ID	S	(18,263,226)	0	0	0	0	(18,263,226)	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - OTHER	S	(113,685)	0	0	0	0	0	0	0	(113,685)	0	
Jurisdictional Tax Depreciation - 12/31/2027 - OR	S	(114,951,077)	0	(114,951,077)	0	0	0	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - SG	SG	(799,561,934)	(11,083,758)	(221,923,010)	(58,652,701)	(356,498,530)	(44,992,779)	(106,378,620)	(32,536)	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - SG-CAGE	SG	(83,605,361)	(1,158,962)	(23,205,148)	(6,132,959)	(37,276,898)	(4,704,623)	(11,123,370)	(3,402)	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - SG-CAGW	SG	(32,755,985)	(454,073)	(9,091,612)	(2,402,849)	(14,604,823)	(1,843,238)	(4,358,057)	(1,333)	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - SO	SO	(119,025,789)	(3,608,837)	(33,218,778)	(8,354,168)	(52,979,651)	(6,399,656)	(14,461,362)	(3,337)	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - UT	S	(195,132,493)	0	0	0	(195,132,493)	0	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - WA	S	(20,293,637)	0	0	(20,293,637)	0	0	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - WY	S	(29,704,930)	0	0	0	0	0	(29,704,930)	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - TOTAL		(1,452,147,228)	(55,044,741)	(402,389,625)	(95,836,313)	(656,492,395)	(76,203,523)	(166,026,338)	(40,609)	(113,685)	0	
Current Total M Difference		(1,452,147,228)	(55,044,741)	(402,389,625)	(95,836,313)	(656,492,395)	(76,203,523)	(166,026,338)	(40,609)	(113,685)	0	
Tax Depr factor		100.0000%	3.7906%	27.7100%	6.5996%	45.2084%	5.2476%	11.4332%	0.0028%	0.0078%	0.0000%	

Pro Forma Factors December 31, 2027
Oregon General Rate Case - December 2027
COINCIDENTAL PEAKS

FORECAST LOADS (CP)

			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-27	12	8	154	2,904	836	3,872	499	1,231	32	9,528
Feb-27	22	8	136	2,704	734	3,858	498	1,242	27	9,198
Mar-27	2	7	125	2,583	643	3,656	427	1,203	35	8,672
Apr-27	13	7	125	2,415	518	3,338	412	1,115	32	7,954
May-27	28	17	113	2,123	602	4,200	579	1,071	33	8,720
Jun-27	25	16	128	2,378	638	5,205	745	1,199	34	10,326
Jul-27	19	17	144	2,887	830	5,716	776	1,171	-	11,524
Aug-27	16	16	132	2,742	815	5,589	620	1,209	-	11,107
Sep-27	7	17	110	2,223	616	4,965	567	1,162	-	9,643
Oct-27	14	18	94	2,153	552	3,909	439	1,141	-	8,288
Nov-27	16	18	116	2,551	672	4,084	459	1,188	-	9,069
Dec-27	21	18	133	2,780	749	4,243	493	1,217	-	9,616
			1,509	30,441	8,206	52,636	6,513	14,148	192	113,645

- (less)

Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)

			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-27	12	8	-	65	18	237	16	41	30	406
Feb-27	22	8	-	65	18	245	16	41	26	409
Mar-27	2	7	-	65	18	244	16	41	34	416
Apr-27	13	7	-	65	18	242	16	41	32	412
May-27	28	17	-	65	18	785	16	41	33	957
Jun-27	25	16	-	93	32	884	193	41	34	1,278
Jul-27	19	17	-	93	32	886	193	41	-	1,246
Aug-27	16	16	-	93	32	893	193	41	-	1,252
Sep-27	7	17	-	65	18	791	16	41	-	930
Oct-27	14	18	-	65	18	249	16	41	-	388
Nov-27	16	18	-	65	18	237	16	41	-	376
Dec-27	21	18	-	65	18	237	16	41	-	376
			-	862	255	5,930	720	490	188	8,445

= equals

COINCIDENTAL PEAK SERVED FROM COMPANY RESOURCES

			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-27	12	8	154	2,839	818	3,636	483	1,190	1	9,122
Feb-27	22	8	136	2,639	717	3,613	483	1,201	1	8,789
Mar-27	2	7	125	2,518	626	3,412	412	1,163	1	8,256
Apr-27	13	7	125	2,350	500	3,097	396	1,074	0	7,542
May-27	28	17	113	2,058	585	3,415	563	1,030	0	7,763
Jun-27	25	16	128	2,284	606	4,320	551	1,158	0	9,048
Jul-27	19	17	144	2,794	798	4,830	583	1,130	-	10,278
Aug-27	16	16	132	2,648	783	4,696	426	1,168	-	9,854
Sep-27	7	17	110	2,158	598	4,174	551	1,121	-	8,713
Oct-27	14	18	94	2,088	534	3,660	424	1,100	-	7,900
Nov-27	16	18	116	2,486	654	3,847	443	1,147	-	8,693
Dec-27	21	18	133	2,715	732	4,007	478	1,176	-	9,240
			1,509	29,579	7,951	46,707	5,793	13,657	4	105,199

+ plus

Adjustments for Ancillary Services Contracts including Reserves and Direct Access (Additions to Load)

			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-27	12	8	-	-	-	30	-	-	-	30
Feb-27	22	8	-	-	-	26	-	-	-	26
Mar-27	2	7	-	-	-	34	-	-	-	34
Apr-27	13	7	-	-	-	32	-	-	-	32
May-27	28	17	-	-	-	33	-	-	-	33
Jun-27	25	16	-	-	-	34	-	-	-	34
Jul-27	19	17	-	-	-	-	-	-	-	-
Aug-27	16	16	-	-	-	-	-	-	-	-
Sep-27	7	17	-	-	-	-	-	-	-	-
Oct-27	14	18	-	-	-	-	-	-	-	-
Nov-27	16	18	-	-	-	-	-	-	-	-
Dec-27	21	18	-	-	-	-	-	-	-	-
			-	-	-	188	-	-	-	188

= equals

LOADS FOR JURISDICTIONAL ALLOCATION (CP)

			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-27	12	8	154	2,839	818	3,666	483	1,190	1	9,152
Feb-27	22	8	136	2,639	717	3,639	483	1,201	1	8,815
Mar-27	2	7	125	2,518	626	3,446	412	1,163	1	8,290
Apr-27	13	7	125	2,350	500	3,128	396	1,074	0	7,574
May-27	28	17	113	2,058	585	3,447	563	1,030	0	7,796
Jun-27	25	16	128	2,284	606	4,354	551	1,158	0	9,082
Jul-27	19	17	144	2,794	798	4,830	583	1,130	-	10,278
Aug-27	16	16	132	2,648	783	4,696	426	1,168	-	9,854
Sep-27	7	17	110	2,158	598	4,174	551	1,121	-	8,713
Oct-27	14	18	94	2,088	534	3,660	424	1,100	-	7,900
Nov-27	16	18	116	2,486	654	3,847	443	1,147	-	8,693
Dec-27	21	18	133	2,715	732	4,007	478	1,176	-	9,240
			1,509	29,579	7,951	46,895	5,793	13,657	4	105,387

Pro Forma Factors December 31, 2027
Oregon General Rate Case - December 2027
ENERGY

FORECAST LOADS (MWH)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2027	1	75,380	1,577,690	418,400	2,607,580	318,620	836,780.00	25,538	5,859,988
2027	2	64,990	1,388,550	350,120	2,290,910	282,710	758,240.00	22,396	5,157,916
2027	3	65,570	1,437,600	336,740	2,386,120	265,940	800,680.00	25,325	5,317,975
2027	4	62,050	1,345,540	300,910	2,280,730	275,920	759,820.00	23,659	5,048,629
2027	5	67,560	1,358,960	311,340	2,393,490	331,690	771,520.00	24,005	5,258,565
2027	6	71,400	1,386,470	320,660	2,683,690	393,150	767,370.00	21,518	5,644,258
2027	7	79,900	1,610,990	416,490	3,125,740	506,890	802,680.00	-	6,542,690
2027	8	75,320	1,580,940	406,910	3,086,990	404,980	807,180.00	-	6,362,320
2027	9	63,030	1,404,090	354,990	2,557,480	313,770	754,630.00	-	5,447,990
2027	10	58,460	1,394,050	360,530	2,401,430	273,950	776,720.00	-	5,265,140
2027	11	63,620	1,485,980	379,550	2,414,550	270,770	772,990.00	-	5,387,460
2027	12	74,660	1,663,630	453,570	2,630,870	318,510	819,740.00	-	5,960,980
		821,940	17,634,490	4,410,210	30,859,580	3,956,900	9,428,350	142,441	67,253,911

- (less)

Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2027	1	-	-	-	59,556	-	-	24,413	83,969
2027	2	-	-	-	81,033	-	-	21,460	102,494
2027	3	-	-	-	111,368	-	-	24,328	135,696
2027	4	-	-	-	112,109	-	-	23,600	135,709
2027	5	-	-	-	141,315	-	-	23,947	165,262
2027	6	-	-	-	193,723	-	-	21,445	215,168
2027	7	-	-	-	245,302	-	-	-	245,302
2027	8	-	-	-	189,443	-	-	-	189,443
2027	9	-	-	-	148,617	-	-	-	148,617
2027	10	-	-	-	106,221	-	-	-	106,221
2027	11	-	-	-	72,507	-	-	-	72,507
2027	12	-	-	-	48,278	-	-	-	48,278
		-	-	-	1,509,474	-	-	139,194	1,648,667

= equals

LOADS SERVED FROM COMPANY RESOURCES (NPC)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2027	1	75,380	1,577,690	418,400	2,548,024	318,620	836,780	1,125	5,776,019
2027	2	64,990	1,388,550	350,120	2,209,877	282,710	758,240	935	5,055,422
2027	3	65,570	1,437,600	336,740	2,274,752	265,940	800,680	997	5,182,279
2027	4	62,050	1,345,540	300,910	2,168,621	275,920	759,820	59	4,912,920
2027	5	67,560	1,358,960	311,340	2,252,175	331,690	771,520	58	5,093,302
2027	6	71,400	1,386,470	320,660	2,489,967	393,150	767,370	72	5,429,089
2027	7	79,900	1,610,990	416,490	2,880,438	506,890	802,680	-	6,297,388
2027	8	75,320	1,580,940	406,910	2,897,547	404,980	807,180	-	6,172,877
2027	9	63,030	1,404,090	354,990	2,408,863	313,770	754,630	-	5,299,373
2027	10	58,460	1,394,050	360,530	2,295,209	273,950	776,720	-	5,158,919
2027	11	63,620	1,485,980	379,550	2,342,043	270,770	772,990	-	5,314,953
2027	12	74,660	1,663,630	453,570	2,582,592	318,510	819,740	-	5,912,702
		821,940	17,634,490	4,410,210	29,350,106	3,956,900	9,428,350	3,247	65,605,243

+ plus

Add: Resolute NTUA (UT) - Grossed up for Line Losses

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2027	1	-	-	-	24,413	-	-	-	24,413
2027	2	-	-	-	21,460	-	-	-	21,460
2027	3	-	-	-	24,328	-	-	-	24,328
2027	4	-	-	-	23,600	-	-	-	23,600
2027	5	-	-	-	23,947	-	-	-	23,947
2027	6	-	-	-	21,445	-	-	-	21,445
2027	7	-	-	-	-	-	-	-	-
2027	8	-	-	-	-	-	-	-	-
2027	9	-	-	-	-	-	-	-	-
2027	10	-	-	-	-	-	-	-	-
2027	11	-	-	-	-	-	-	-	-
2027	12	-	-	-	-	-	-	-	-
		-	-	-	139,194	-	-	-	139,194

= equals

LOADS FOR JURISDICTIONAL ALLOCATION (MWh)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2027	1	75,380	1,577,690	418,400	2,572,437	318,620	836,780	1,125	5,800,432
2027	2	64,990	1,388,550	350,120	2,231,337	282,710	758,240	935	5,076,883
2027	3	65,570	1,437,600	336,740	2,299,080	265,940	800,680	997	5,206,607
2027	4	62,050	1,345,540	300,910	2,192,221	275,920	759,820	59	4,936,520
2027	5	67,560	1,358,960	311,340	2,276,122	331,690	771,520	58	5,117,250
2027	6	71,400	1,386,470	320,660	2,511,412	393,150	767,370	72	5,450,534
2027	7	79,900	1,610,990	416,490	2,880,438	506,890	802,680	-	6,297,388
2027	8	75,320	1,580,940	406,910	2,897,547	404,980	807,180	-	6,172,877
2027	9	63,030	1,404,090	354,990	2,408,863	313,770	754,630	-	5,299,373
2027	10	58,460	1,394,050	360,530	2,295,209	273,950	776,720	-	5,158,919
2027	11	63,620	1,485,980	379,550	2,342,043	270,770	772,990	-	5,314,953
2027	12	74,660	1,663,630	453,570	2,582,592	318,510	819,740	-	5,912,702
		821,940	17,634,490	4,410,210	29,489,300	3,956,900	9,428,350	3,247	65,744,437

Pro Forma Factors December 31, 2027
Oregon General Rate Case - December 2027

	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC		
Subtotal	821,940	17,634,490	4,410,210	29,489,300	3,956,900	9,428,350	3,247	**65,744,437**	**Ref Page 10.12**
System Energy Factor	1.250%	26.823%	6.708%	44.854%	6.019%	14.3409%	0.005%	100.00%	
Divisional Energy - Pacific	2.649%	56.836%	14.214%	0.000%	0.000%	26.3012%	0.000%	100.00%	
Divisional Energy - Utah	0.000%	0.000%	0.000%	84.941%	11.397%	3.6519%	0.009%	100.00%	
System Generation Factor	1.386%	27.756%	7.336%	44.587%	5.627%	13.3046%	0.004%	100.00%	
Divisional Generation - Pacific	2.889%	57.843%	15.287%	0.000%	0.000%	23.9806%	0.000%	100.00%	
Divisional Generation - Utah	0.000%	0.000%	0.000%	85.718%	10.818%	3.4560%	0.008%	100.00%	
System Capacity (kw)									
Accord	1,509	29,579	7,951	46,895	5,793	13,657.3	4	**105,387**	**Ref Page 10.11**
Modified Accord	1,509	29,579	7,951	46,895	5,793	13,657.3	4	**105,387**	**Ref Page 10.11**
Rolled-In	1,509	29,579	7,951	46,895	5,793	13,657.3	4	**105,387**	**Ref Page 10.11**
Rolled-In with Hydro Adj.	1,509	29,579	7,951	46,895	5,793	13,657.3	4	**105,387**	**Ref Page 10.11**
Rolled-In with Off-Sys Adj.	1,509	29,579	7,951	46,895	5,793	13,657.3	4	**105,387**	**Ref Page 10.11**
System Capacity Factor									
Accord	1.432%	28.067%	7.545%	44.497%	5.497%	12.9592%	0.004%	100.00%	
Modified Accord	1.432%	28.067%	7.545%	44.497%	5.497%	12.9592%	0.004%	100.00%	
Rolled-In	1.432%	28.067%	7.545%	44.497%	5.497%	12.9592%	0.004%	100.00%	
Rolled-In with Hydro Adj.	1.432%	28.067%	7.545%	44.497%	5.497%	12.9592%	0.004%	100.00%	
Rolled-In with Off-Sys Adj.	1.432%	28.067%	7.545%	44.497%	5.497%	12.9592%	0.004%	100.00%	
System Energy (kwh)									
Accord	821,940	17,634,490	4,410,210	29,489,300	3,956,900	9,428,350	3,247	65,744,437	
Modified Accord	821,940	17,634,490	4,410,210	29,489,300	3,956,900	9,428,350	3,247	65,744,437	
Rolled-In	821,940	17,634,490	4,410,210	29,489,300	3,956,900	9,428,350	3,247	65,744,437	
Rolled-In with Hydro Adj.	821,940	17,634,490	4,410,210	29,489,300	3,956,900	9,428,350	3,247	65,744,437	
Rolled-In with Off-Sys Adj.	821,940	17,634,490	4,410,210	29,489,300	3,956,900	9,428,350	3,247	65,744,437	
System Energy Factor									
Accord	1.250%	26.823%	6.708%	44.854%	6.019%	14.3409%	0.005%	100.00%	
Modified Accord	1.250%	26.823%	6.708%	44.854%	6.019%	14.3409%	0.005%	100.00%	
Rolled-In	1.250%	26.823%	6.708%	44.854%	6.019%	14.3409%	0.005%	100.00%	
Rolled-In with Hydro Adj.	1.250%	26.823%	6.708%	44.854%	6.019%	14.3409%	0.005%	100.00%	
Rolled-In with Off-Sys Adj.	1.250%	26.823%	6.708%	44.854%	6.019%	14.3409%	0.005%	100.00%	
System Generation Factor									
Accord	1.386%	27.756%	7.336%	44.587%	5.627%	13.3046%	0.004%	100.00%	
Modified Accord	1.386%	27.756%	7.336%	44.587%	5.627%	13.3046%	0.004%	100.00%	
Rolled-In	1.386%	27.756%	7.336%	44.587%	5.627%	13.3046%	0.004%	100.00%	
Rolled-In with Hydro Adj.	1.386%	27.756%	7.336%	44.587%	5.627%	13.3046%	0.004%	100.00%	
Rolled-In with Off-Sys Adj.	1.386%	27.756%	7.336%	44.587%	5.627%	13.3046%	0.004%	100.00%	

B-Tabs

B1. REVENUE

PACIFICORP

Electric Operations Revenue (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4118000	GAINS-DISP OF ALLOW	0	SO2 ALLOWANCE	SE	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
4118000 Total					**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**-**
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	OR	246	-	246	-	-	-	-	-	-
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	SO	(5,865)	(178)	(1,637)	(412)	(713)	(2,610)	(315)	(0)	-
4211000 Total					**(5,619)**	**(178)**	**(1,391)**	**(412)**	**(713)**	**(2,610)**	**(315)**	**(0)**	**-**
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	SG	10	0	3	1	1	5	1	0	-
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	SG-P	21	0	6	2	3	10	1	0	-
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	SO	(10)	(0)	(3)	(1)	(1)	(5)	(1)	(0)	-
4212000 Total					**21**	**0**	**6**	**2**	**3**	**10**	**1**	**0**	**-**
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	CA	67,278	67,278	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	IDU	107,872	-	-	-	-	-	107,872	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	OR	896,126	-	896,126	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	UT	936,223	-	-	-	-	936,223	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WA	204,627	-	-	204,627	-	-	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WYP	127,420	-	-	-	127,420	-	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WYU	16,474	-	-	-	16,474	-	-	-	-
4401000	RESIDENTIAL SALES	301102	Special Contracts 32/34-Residential	UT	58	-	-	-	-	58	-	-	-
4401000	RESIDENTIAL SALES	301103	Net Metering-Residential	UT	30,939	-	-	-	-	30,939	-	-	-
4401000	RESIDENTIAL SALES	301106	Residential-Alt Revenue Program Adjs	WA	23,406	-	-	23,406	-	-	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	CA	(1,017)	(1,017)	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	IDU	287	-	-	-	-	-	287	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	OR	(8,943)	-	(8,943)	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	UT	35,077	-	-	-	-	35,077	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	WA	(8,825)	-	-	(8,825)	-	-	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	WYP	33	-	-	-	33	-	-	-	-
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	CA	189	189	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	UT	141,706	-	-	-	-	141,706	-	-	-
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	WA	1,092	-	-	1,092	-	-	-	-	-
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	WYP	(252)	-	-	-	(252)	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	CA	126	126	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	IDU	1,012	-	-	-	-	-	1,012	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	OR	2,816	-	2,816	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	UT	(6,819)	-	-	-	-	(6,819)	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WA	6,598	-	-	6,598	-	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WYP	2,189	-	-	-	2,189	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WYU	(156)	-	-	-	(156)	-	-	-	-
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	WA	830	-	-	830	-	-	-	-	-
4401000	RESIDENTIAL SALES	301111	Residential-OR Corp Act Tax Rev Adj	OTHER	(7)	-	-	-	-	-	-	-	(7)
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	CA	(93)	(93)	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	IDU	(259)	-	-	-	-	-	(259)	-	-
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	OR	(1,734)	-	(1,734)	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	UT	(3,595)	-	-	-	-	(3,595)	-	-	-
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	WA	(108)	-	-	(108)	-	-	-	-	-
4401000	RESIDENTIAL SALES	301165	Solar Feed-In Revenue - Residential	OTHER	1,325	-	-	-	-	-	-	-	1,325
4401000	RESIDENTIAL SALES	301168	Community Solar Revenue-Residential	OTHER	703	-	-	-	-	-	-	-	703
4401000	RESIDENTIAL SALES	301170	DSM Revenue - Residential	OTHER	76,256	-	-	-	-	-	-	-	76,256
4401000	RESIDENTIAL SALES	301171	DSM Revenue - Residential Cat 2 Gen Svc	OTHER	46	-	-	-	-	-	-	-	46
4401000	RESIDENTIAL SALES	301180	Blue Sky Revenue Residential	OTHER	3,851	-	-	-	-	-	-	-	3,851
4401000	RESIDENTIAL SALES	301190	Other Cust Retail Revenue-Residential	OTHER	2,490	-	-	-	-	-	-	-	2,490
4401000 Total					**2,655,241**	**66,483**	**888,265**	**227,619**	**145,708**	**1,133,589**	**108,912**	**-**	**84,664**
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	CA	47,690	47,690	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	IDU	63,328	-	-	-	-	-	63,328	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	OR	738,239	-	738,239	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	UT	848,134	-	-	-	-	848,134	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WA	174,413	-	-	174,413	-	-	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WYP	140,892	-	-	-	140,892	-	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WYU	14,324	-	-	-	14,324	-	-	-	-
4421000	COMMERCIAL SALES	301204	Special Contracts 32/34-Commercial	UT	49,280	-	-	-	-	49,280	-	-	-
4421000	COMMERCIAL SALES	301206	Commercial-Alt Revenue Program Adjs	WA	(13,699)	-	-	(13,699)	-	-	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	CA	(634)	(634)	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	IDU	169	-	-	-	-	-	169	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	OR	(7,591)	-	(7,591)	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	UT	30,176	-	-	-	-	30,176	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	WA	(9,570)	-	-	(9,570)	-	-	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	WYP	44	-	-	-	44	-	-	-	-
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	CA	116	116	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	UT	183,591	-	-	-	-	183,591	-	-	-
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	WA	1,028	-	-	1,028	-	-	-	-	-

PACIFICORP

Electric Operations Revenue (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	WYP	(344)	-	-	-	(344)	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	CA	(128)	(128)	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	IDU	(206)	-	-	-	-	-	(206)	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	OR	17,155	-	17,155	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	UT	8,579	-	-	-	-	8,579	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WA	1,772	-	-	1,772	-	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WYP	(469)	-	-	-	(469)	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WYU	(39)	-	-	-	(39)	-	-	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	WA	782	-	-	782	-	-	-	-	-
4421000	COMMERCIAL SALES	301211	Commercial-OR Corp Act Tax Alt Rev Adj	OTHER	(2)	-	-	-	-	-	-	-	(2)
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	CA	(17)	(17)	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	IDU	(30)	-	-	-	-	-	(30)	-	-
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	OR	(223)	-	(223)	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	UT	(324)	-	-	-	-	(324)	-	-	-
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	WA	(84)	-	-	(84)	-	-	-	-	-
4421000	COMMERCIAL SALES	301265	Solar Feed-In Revenue - Commercial	OTHER	1,343	-	-	-	-	-	-	-	1,343
4421000	COMMERCIAL SALES	301268	Community Solar Revenue-Commercial	OTHER	772	-	-	-	-	-	-	-	772
4421000	COMMERCIAL SALES	301270	DSM Revenue - Commercial	OTHER	79,016	-	-	-	-	-	-	-	79,016
4421000	COMMERCIAL SALES	301271	DSM Revenue - Small Commercial	OTHER	3,517	-	-	-	-	-	-	-	3,517
4421000	COMMERCIAL SALES	301272	DSM Revenue - Large Commercial	OTHER	157	-	-	-	-	-	-	-	157
4421000	COMMERCIAL SALES	301280	Blue Sky Revenue - Commercial	OTHER	2,567	-	-	-	-	-	-	-	2,567
4421000	COMMERCIAL SALES	301290	Other Cust Retail Revenue-Commercial	OTHER	3,195	-	-	-	-	-	-	-	3,195
4421000 Total					**2,376,920**	**47,027**	**747,580**	**154,643**	**154,408**	**1,119,436**	**63,261**	**-**	**90,566**
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	CA	8,378	8,378	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	IDU	22,546	-	-	-	-	-	22,546	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	OR	151,149	-	151,149	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	UT	325,206	-	-	-	-	325,206	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WA	71,984	-	-	71,984	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WYP	422,911	-	-	-	422,911	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WYU	75,975	-	-	-	75,975	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301304	SPECIAL CONTRACTS-SITUS	IDU	108,026	-	-	-	-	-	108,026	-	-
4422000	IND SLS/EXCL IRRIG	301304	SPECIAL CONTRACTS-SITUS	UT	104,504	-	-	-	-	104,504	-	-	-
4422000	IND SLS/EXCL IRRIG	301306	Industrial-Alt Revenue Program Adjs	WA	(624)	-	-	(624)	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	CA	(113)	(113)	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	IDU	59	-	-	-	-	-	59	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	OR	(2,162)	-	(2,162)	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	UT	12,665	-	-	-	-	12,665	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	WA	(4,115)	-	-	(4,115)	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	WYP	27	-	-	-	27	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	CA	31	31	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	UT	118,533	-	-	-	-	118,533	-	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	WA	438	-	-	438	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	WYP	(1,473)	-	-	-	(1,473)	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	CA	18	18	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	IDU	(404)	-	-	-	-	-	(404)	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	OR	(3,668)	-	(3,668)	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	UT	(125)	-	-	-	-	(125)	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WA	(560)	-	-	(560)	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WYP	9,586	-	-	-	9,586	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WYU	(75)	-	-	-	(75)	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	WA	336	-	-	336	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301311	Industrial-OR Corp Act Tax Rev Adj	OTHER	0	-	-	-	-	-	-	-	0
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	CA	(0)	(0)	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	IDU	(1)	-	-	-	-	-	(1)	-	-
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	OR	(4)	-	(4)	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	UT	(13)	-	-	-	-	(13)	-	-	-
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	WA	(2)	-	-	(2)	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301313	Special Contracts 32/34-Industrial	UT	519	-	-	-	-	519	-	-	-
4422000	IND SLS/EXCL IRRIG	301365	Solar Feed-In Revenue - Industrial	OTHER	282	-	-	-	-	-	-	-	282
4422000	IND SLS/EXCL IRRIG	301368	Community Solar Revenue-Industrial	OTHER	167	-	-	-	-	-	-	-	167
4422000	IND SLS/EXCL IRRIG	301370	DSM Revenue - Industrial	OTHER	27,307	-	-	-	-	-	-	-	27,307
4422000	IND SLS/EXCL IRRIG	301371	DSM Revenue - Small Industrial	OTHER	779	-	-	-	-	-	-	-	779
4422000	IND SLS/EXCL IRRIG	301372	DSM Revenue - Large Industrial	OTHER	3,187	-	-	-	-	-	-	-	3,187
4422000	IND SLS/EXCL IRRIG	301380	Blue Sky Revenue - Industrial	OTHER	921	-	-	-	-	-	-	-	921
4422000	IND SLS/EXCL IRRIG	301390	Other Cust Retail Revenue-Industrial	OTHER	1,652	-	-	-	-	-	-	-	1,652
4422000 Total					**1,453,848**	**8,313**	**145,316**	**67,457**	**506,952**	**561,290**	**130,226**	**-**	**34,294**
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	CA	16,037	16,037	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	IDU	78,247	-	-	-	-	-	78,247	-	-

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Electric Operations Revenue (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	OR	30,876	-	30,876	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	UT	19,683	-	-	-	-	19,683	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WA	19,918	-	-	19,918	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WYP	2,805	-	-	-	2,805	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WYU	856	-	-	-	856	-	-	-	-
4423000	INDUST SALES-IRRIG	301452	Special Contracts 32/34-Irrigation	UT	11	-	-	-	-	11	-	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	CA	(3)	(3)	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	IDU	(5)	-	-	-	-	-	(5)	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	OR	(14)	-	(14)	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	UT	(4)	-	-	-	-	(4)	-	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	WA	(19)	-	-	(19)	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301454	Irrigation-OR Corp Act Tax Rev Adj	OTHER	(0)	-	-	-	-	-	-	-	(0)
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	WA	85	-	-	85	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	CA	(227)	(227)	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	IDU	206	-	-	-	-	-	206	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	OR	(287)	-	(287)	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	UT	754	-	-	-	-	754	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	WA	(898)	-	-	(898)	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	WYP	1	-	-	-	1	-	-	-	-
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	CA	48	48	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	UT	3,562	-	-	-	-	3,562	-	-	-
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	WA	111	-	-	111	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	WYP	(7)	-	-	-	(7)	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	CA	247	247	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	IDU	5,717	-	-	-	-	-	5,717	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	OR	388	-	388	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	UT	70	-	-	-	-	70	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WA	376	-	-	376	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WYP	217	-	-	-	217	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WYU	(46)	-	-	-	(46)	-	-	-	-
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Charg	CA	(8)	(8)	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Charg	OR	183	-	183	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Charg	WA	179	-	-	179	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301465	Solar Feed-In Revenue - Irrigation	OTHER	38	-	-	-	-	-	-	-	38
4423000	INDUST SALES-IRRIG	301468	Community Solar Revenue-Irrigation	OTHER	25	-	-	-	-	-	-	-	25
4423000	INDUST SALES-IRRIG	301470	DSM Revenue - Irrigation	OTHER	4,720	-	-	-	-	-	-	-	4,720
4423000	INDUST SALES-IRRIG	301480	Blue Sky Revenue - Irrigation	OTHER	3	-	-	-	-	-	-	-	3
4423000	INDUST SALES-IRRIG	301490	Other Cust Retail Revenue-Irrigation	OTHER	73	-	-	-	-	-	-	-	73
4423000 Total					**183,916**	**16,094**	**31,147**	**19,752**	**3,825**	**24,076**	**84,165**	**-**	**4,859**
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	CA	520	520	-	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	IDU	511	-	-	-	-	-	511	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	OR	5,402	-	5,402	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	UT	5,778	-	-	-	-	5,778	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WA	775	-	-	775	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WYP	1,867	-	-	-	1,867	-	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WYU	313	-	-	-	313	-	-	-	-
4441000	PUB ST/HWY LIGHT	301602	Special Contracts 32/34-Street Lighting	UT	23	-	-	-	-	23	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	CA	(4)	(4)	-	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	IDU	3	-	-	-	-	-	3	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	OR	(41)	-	(41)	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	UT	240	-	-	-	-	240	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	WA	(42)	-	-	(42)	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	WYU	0	-	-	-	0	-	-	-	-
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	CA	1	1	-	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	UT	945	-	-	-	-	945	-	-	-
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	WA	3	-	-	3	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	WYP	(3)	-	-	-	(3)	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	CA	6	6	-	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	IDU	(2)	-	-	-	-	-	(2)	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	OR	40	-	40	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	UT	(75)	-	-	-	-	(75)	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WA	(6)	-	-	(6)	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WYP	(61)	-	-	-	(61)	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WYU	4	-	-	-	4	-	-	-	-
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	WA	2	-	-	2	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301612	St&Hwy Light - Customer Bill Credits	IDU	(0)	-	-	-	-	-	(0)	-	-
4441000	PUB ST/HWY LIGHT	301612	St&Hwy Light - Customer Bill Credits	OR	(2)	-	(2)	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301612	St&Hwy Light - Customer Bill Credits	UT	(1)	-	-	-	-	(1)	-	-	-

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Electric Operations Revenue (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4441000	PUB ST/HWY LIGHT	301665	Solar Feed-In Revenue - St/Hwy Lighting	OTHER	3	-	-	-	-	-	-	-	3
4441000	PUB ST/HWY LIGHT	301668	Community Solar Revenue-St/Hwy Lightg	OTHER	2	-	-	-	-	-	-	-	2
4441000	PUB ST/HWY LIGHT	301670	DSM Revenue - Street/Hwy Lighting	OTHER	442	-	-	-	-	-	-	-	442
4441000	PUB ST/HWY LIGHT	301690	Other Cust Retail Revenue-St/Hwy Lightg	OTHER	15	-	-	-	-	-	-	-	15
4441000 Total					**16,658**	**523**	**5,398**	**732**	**2,120**	**6,910**	**512**	**-**	**462**
4471000	ON-SYS WHOLE-FIRM	301443	ON SYS FIRM-UTAH FERC CUSTOMERS	FERC	16,883	-	-	-	-	-	-	16,883	-
4471000	ON-SYS WHOLE-FIRM	301445	On Sys Firm-Utah W/S Customers-Deferral	UT	(47)	-	-	-	-	(47)	-	-	-
4471000 Total					**16,836**	**-**	**-**	**-**	**-**	**(47)**	**-**	**16,883**	**-**
4471300	POST MERGER FIRM	301405	POST MERGER FIRM	SG	12,718	176	3,530	933	1,692	5,671	716	1	-
4471300 Total					**12,718**	**176**	**3,530**	**933**	**1,692**	**5,671**	**716**	**1**	**-**
4471400	S/T FIRM WHOLESALE	301406	SHORT-TERM FIRM WHOLESALE SALES	SG	133,786	1,855	37,133	9,814	17,800	59,651	7,528	5	-
4471400	S/T FIRM WHOLESALE	301410	TRADING SALES NETTED	SG	(268)	(4)	(74)	(20)	(36)	(119)	(15)	(0)	-
4471400	S/T FIRM WHOLESALE	301411	BOOKOUT SALES NETTED	SG	(36,766)	(510)	(10,204)	(2,697)	(4,892)	(16,393)	(2,069)	(1)	-
4471400	S/T FIRM WHOLESALE	301412	BOOKOUT SALES NETTED-ESTIMATE	SG	14	0	4	1	2	6	1	0	-
4471400	S/T FIRM WHOLESALE	302752	I/C S-T Firm Wholesale Sales-Nevada Pwr	SG	16	0	4	1	2	7	1	0	-
4471400	S/T FIRM WHOLESALE	302772	I/C Line Loss Trading Revenue-Nevada Pwr	SG	24	0	7	2	3	11	1	0	-
4471400	S/T FIRM WHOLESALE	303028	LINE LOSS W/S TRADING REVENUES	SG	10,277	142	2,853	754	1,367	4,582	578	0	-
4471400 Total					**107,084**	**1,484**	**29,722**	**7,855**	**14,247**	**47,745**	**6,026**	**4**	**-**
4472000	SLS FOR RESL-SURP	301419	ESTIMATED SALES FOR RESALE REVENUE	SG	2,429	34	674	178	323	1,083	137	0	-
4472000	SLS FOR RESL-SURP	302762	I/C Wholesale Sales Estimate-Nevada Pwr	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
4472000	SLS FOR RESL-SURP	303198	Non-ASC 606-WS NPC Rev-Derivativ (Disc)	SG	74,188	1,028	20,591	5,442	9,870	33,078	4,175	3	-
4472000	SLS FOR RESL-SURP	303199	Non-ASC 606-WS NPC Rev-Derivativ (Recl)	SG	(74,188)	(1,028)	(20,591)	(5,442)	(9,870)	(33,078)	(4,175)	(3)	-
4472000 Total					**2,429**	**34**	**674**	**178**	**323**	**1,083**	**137**	**0**	**-**
4475000	OFF-SYS - NON FIRM	301408	OFF-SYSTEM WHOLESALE - NON FIRM	SE	(1,507)	(19)	(404)	(101)	(216)	(676)	(91)	(0)	-
4475000 Total					**(1,507)**	**(19)**	**(404)**	**(101)**	**(216)**	**(676)**	**(91)**	**(0)**	**-**
4476100	BOOKOUTS NETTED-GAI	304101	BOOKOUTS NETTED-GAIN	SG	2,657	37	737	195	353	1,185	150	0	-
4476100	BOOKOUTS NETTED-GAI	304102	BOOKOUTS NETTED-EST GAIN	SG	(40)	(1)	(11)	(3)	(5)	(18)	(2)	(0)	-
4476100 Total					**2,616**	**36**	**726**	**192**	**348**	**1,167**	**147**	**0**	**-**
4476200	TRADING NETTED-GAINS	304201	TRADING NETTED-GAINS	SG	37	1	10	3	5	17	2	0	-
4476200 Total					**37**	**1**	**10**	**3**	**5**	**17**	**2**	**0**	**-**
4479000	TRANS SRVC	301428	TRANS SERV-UTAH FERC CUSTOMERS	FERC	57	-	-	-	-	-	-	57	-
4479000 Total					**57**	**-**	**-**	**-**	**-**	**-**	**-**	**57**	**-**
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	CA	324	324	-	-	-	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	IDU	277	-	-	-	-	-	277	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	OR	3,922	-	3,922	-	-	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	UT	3,766	-	-	-	-	3,766	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WA	14	-	-	14	-	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WYP	697	-	-	-	697	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WYU	78	-	-	-	78	-	-	-	-
4501000 Total					**9,077**	**324**	**3,922**	**14**	**775**	**3,766**	**277**	**-**	**-**
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	CA	112	112	-	-	-	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	IDU	41	-	-	-	-	-	41	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	OR	2,273	-	2,273	-	-	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	UT	881	-	-	-	-	881	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WA	99	-	-	99	-	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WYP	157	-	-	-	157	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WYU	47	-	-	-	47	-	-	-	-
4502000 Total					**3,610**	**112**	**2,273**	**99**	**204**	**881**	**41**	**-**	**-**
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	CA	58	58	-	-	-	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	IDU	270	-	-	-	-	-	270	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	OR	406	-	406	-	-	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	UT	317	-	-	-	-	317	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WA	29	-	-	29	-	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WYP	161	-	-	-	161	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WYU	98	-	-	-	98	-	-	-	-
4503000 Total					**1,339**	**58**	**406**	**29**	**259**	**317**	**270**	**-**	**-**
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	CA	0	0	-	-	-	-	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	IDU	0	-	-	-	-	-	0	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	OR	24	-	24	-	-	-	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	UT	61	-	-	-	-	61	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	WA	2	-	-	2	-	-	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	WYP	7	-	-	-	7	-	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	WYU	0	-	-	-	0	-	-	-	-
4504000 Total					**95**	**0**	**24**	**2**	**7**	**61**	**0**	**-**	**-**
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	CA	342	342	-	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	IDU	88	-	-	-	-	-	88	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	OR	895	-	895	-	-	-	-	-	-

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Electric Operations Revenue (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	UT	3,684	-	-	-	-	3,684	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WA	36	-	-	36	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WYP	88	-	-	-	88	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WYU	13	-	-	-	13	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	CA	19	19	-	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	IDU	44	-	-	-	-	-	44	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	OR	339	-	339	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	UT	640	-	-	-	-	640	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WA	72	-	-	72	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WYP	62	-	-	-	62	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WYU	7	-	-	-	7	-	-	-	-
4511000 Total					**6,329**	**361**	**1,235**	**107**	**171**	**4,324**	**132**	**-**	**-**
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CH(	CA	0	0	-	-	-	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CH(	OR	3	-	3	-	-	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CH(	UT	1	-	-	-	-	1	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CH(	WA	1	-	-	1	-	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CH(	WYP	0	-	-	-	0	-	-	-	-
4512000 Total					**5**	**0**	**3**	**1**	**0**	**1**	**-**	**-**	**-**
4513000	OTHER	301828	OTHER	CA	(2)	(2)	-	-	-	-	-	-	-
4513000	OTHER	301828	OTHER	IDU	3	-	-	-	-	-	3	-	-
4513000	OTHER	301828	OTHER	OR	(705)	-	(705)	-	-	-	-	-	-
4513000	OTHER	301828	OTHER	SO	68	2	19	5	8	30	4	0	-
4513000	OTHER	301828	OTHER	UT	2,731	-	-	-	-	2,731	-	-	-
4513000	OTHER	301828	OTHER	WA	159	-	-	159	-	-	-	-	-
4513000	OTHER	301828	OTHER	WYP	134	-	-	-	134	-	-	-	-
4513000	OTHER	301828	OTHER	WYU	7	-	-	-	7	-	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	CA	18	18	-	-	-	-	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	IDU	40	-	-	-	-	-	40	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	OR	18	-	18	-	-	-	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	UT	390	-	-	-	-	390	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	WA	60	-	-	60	-	-	-	-	-
4513000 Total					**2,922**	**18**	**(668)**	**224**	**149**	**3,151**	**47**	**0**	**-**
4530000	SLS WATER & W PWR	358900	Sales of Water & Water Power	SG	6	0	2	0	1	3	0	0	-
4530000 Total					**6**	**0**	**2**	**0**	**1**	**3**	**0**	**0**	**-**
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	CA	2	2	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	IDU	1	-	-	-	-	-	1	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	OR	831	-	831	-	-	-	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	SG	1,299	18	361	95	173	579	73	0	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	SO	3,732	113	1,042	262	453	1,661	201	0	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	UT	1,447	-	-	-	-	1,447	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	WA	11	-	-	11	-	-	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	WYP	14	-	-	-	14	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	CA	807	807	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	IDU	154	-	-	-	-	-	154	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	OR	5,673	-	5,673	-	-	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	UT	2,352	-	-	-	-	2,352	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	WA	634	-	-	634	-	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	WYP	326	-	-	-	326	-	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	OR	152	-	152	-	-	-	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	UT	49	-	-	-	-	49	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	WA	0	-	-	0	-	-	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	WYP	1	-	-	-	1	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	CA	6	6	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	IDU	107	-	-	-	-	-	107	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	OR	522	-	522	-	-	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	UT	402	-	-	-	-	402	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	WA	33	-	-	33	-	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	WYP	17	-	-	-	17	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	CA	2	2	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	IDU	(50)	-	-	-	-	-	(50)	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	OR	(19)	-	(19)	-	-	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	UT	(65)	-	-	-	-	(65)	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	WA	15	-	-	15	-	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	WYP	(3)	-	-	-	(3)	-	-	-	-
4541000	RENTS - COMMON	301872	RENT REV - TRANS	SG	190	3	53	14	25	85	11	0	-
4541000	RENTS - COMMON	301874	RENT REV - GENERAL	SO	0	0	0	0	0	0	0	0	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	CA	14	14	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	IDU	13	-	-	-	-	-	13	-	-

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Electric Operations Revenue (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	OR	104	-	104	-	-	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	UT	379	-	-	-	-	379	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	WA	129	-	-	129	-	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	WYP	66	-	-	-	66	-	-	-	-
4541000 Total					**19,347**	**965**	**8,717**	**1,194**	**1,073**	**6,889**	**509**	**0**	**-**
4543000	MCI FOGWIRE REVENUE	301863	MCI FIBER OPTIC GROUND WIRE REVENUES	SG	730	10	203	54	97	325	41	0	-
4543000 Total					**730**	**10**	**203**	**54**	**97**	**325**	**41**	**0**	**-**
4561100	Other Wheeling Rev	301953	Ancillary Rev Sch 6-Supp (C&T)	SG	2,836	39	787	208	377	1,264	160	0	-
4561100	Other Wheeling Rev	301963	Ancil Revenue Sch 2-Reactive (C&T)	SG	4,184	58	1,161	307	557	1,865	235	0	-
4561100	Other Wheeling Rev	301966	Primary Delivery and Distribution Sub Ch	SG	425	6	118	31	57	190	24	0	-
4561100	Other Wheeling Rev	301967	Ancillary Revenue Sch 1 - Scheduling	SG	3,042	42	844	223	405	1,356	171	0	-
4561100	Other Wheeling Rev	301969	Ancillary Revenue Sch 3 - Reg&Freq (C&T)	SG	2,143	30	595	157	285	955	121	0	-
4561100	Other Wheeling Rev	301973	Ancillary Revenue Sch 5&6-Spin&Supp (C&T	SG	2,519	35	699	185	335	1,123	142	0	-
4561100	Other Wheeling Rev	301974	Ancil Revenue Sch 3a-Regulation (C&T)	SG	5,196	72	1,442	381	691	2,317	292	0	-
4561100	Other Wheeling Rev	302082	I/C Anc Rev Sch 1-Scheduling-Nevada Pwr	SG	2	0	1	0	0	1	0	0	-
4561100	Other Wheeling Rev	302092	I/C Anc Rev Sch 2-Reactive-Nevada Pwr	SG	4	0	1	0	0	2	0	0	-
4561100	Other Wheeling Rev	302831	I/C Other Wheeling Revenue-Sierra Pac	SG	33	0	9	2	4	15	2	0	-
4561100	Other Wheeling Rev	302901	USE OF FACILITY REVENUE	SG	705	10	196	52	94	314	40	0	-
4561100	Other Wheeling Rev	302981	Transmission Resales to Other Parties	SG	(913)	(13)	(253)	(67)	(121)	(407)	(51)	(0)	-
4561100	Other Wheeling Rev	302982	Transmission Rev-Unreserved Use Charges	SG	198	3	55	15	26	88	11	0	-
4561100	Other Wheeling Rev	302983	Transmission Revenue - Deferral Fees	SG	1,394	19	387	102	185	621	78	0	-
4561100 Total					**21,768**	**302**	**6,042**	**1,597**	**2,896**	**9,706**	**1,225**	**1**	**-**
4561910	S/T FIRM WHEEL REV	301926	SHORT TERM FIRM WHEELING	SG	22,898	317	6,356	1,680	3,047	10,210	1,289	1	-
4561910 Total					**22,898**	**317**	**6,356**	**1,680**	**3,047**	**10,210**	**1,289**	**1**	**-**
4561920	L/T FIRM WHEEL REV	301912	POST-MERGER FIRM WHEELING	SG	27,366	379	7,595	2,007	3,641	12,201	1,540	1	-
4561920	L/T FIRM WHEEL REV	301916	PRE-MERGER FIRM WHEELING	SG	7,203	100	1,999	528	958	3,211	405	0	-
4561920	L/T FIRM WHEEL REV	301917	PRE-MERGER FIRM WHEELING	SG	49,908	692	13,852	3,661	6,640	22,252	2,808	2	-
4561920	L/T FIRM WHEEL REV	302961	TRANSM CAPACITY RE-ASSIGNMENT REVENUE	SG	3,511	49	975	258	467	1,565	198	0	-
4561920	L/T FIRM WHEEL REV	302962	TRANSM CAPACITY RE-ASSIGNMENT CONTRA RE	SG	(3,511)	(49)	(975)	(258)	(467)	(1,565)	(198)	(0)	-
4561920	L/T FIRM WHEEL REV	302980	Transmisson Point-to-Point Revenue	SG	72,843	1,010	20,218	5,343	9,691	32,478	4,099	3	-
4561920 Total					**157,319**	**2,181**	**43,665**	**11,540**	**20,931**	**70,143**	**8,853**	**6**	**-**
4561930	NON-FIRM WHEEL REV	301922	NON-FIRM WHEELING REVENUE	SE	27,303	341	7,323	1,832	3,916	12,247	1,643	1	-
4561930	NON-FIRM WHEEL REV	302822	I/C Non-Firm Wheeling Revenue-Nevada Pwr	SE	135	2	36	9	19	60	8	0	-
4561930 Total					**27,438**	**343**	**7,360**	**1,841**	**3,935**	**12,307**	**1,651**	**1**	**-**
4561990	TRANSMN REV REFUND	301913	Transmission Tariff True-up	SG	(19,781)	(274)	(5,490)	(1,451)	(2,632)	(8,820)	(1,113)	(1)	-
4561990	TRANSMN REV REFUND	302990	L-T Transm Revenue - Subject to Refund	SG	(15,248)	(211)	(4,232)	(1,119)	(2,029)	(6,799)	(858)	(1)	-
4561990 Total					**(35,029)**	**(486)**	**(9,723)**	**(2,570)**	**(4,660)**	**(15,618)**	**(1,971)**	**(1)**	**-**
4562100	USE OF FACIL REV	301911	"INCOME FROM FISH, WILDLIFE"	SG	2	0	1	0	0	1	0	0	-
4562100 Total					**2**	**0**	**1**	**0**	**0**	**1**	**0**	**0**	**-**
4562300	MISC OTHER REV	301900	ELECTRIC INCOME OTHER	SG	4,475	62	1,242	328	595	1,995	252	0	-
4562300	MISC OTHER REV	301900	ELECTRIC INCOME OTHER	UT	24	-	-	-	-	24	-	-	-
4562300	MISC OTHER REV	301915	OTHER ELEC REV - MISC	OR	126	-	126	-	-	-	-	-	-
4562300	MISC OTHER REV	301915	OTHER ELEC REV - MISC	SG	2,596	36	721	190	345	1,158	146	0	-
4562300	MISC OTHER REV	301939	Estimated Other Electric Revenue	SG	533	7	148	39	71	238	30	0	-
4562300	MISC OTHER REV	301940	FLYASH & BY-PRODUCT SALES	OTHER	1,499	-	-	-	-	-	-	-	1,499
4562300	MISC OTHER REV	301940	FLYASH & BY-PRODUCT SALES	SG	8,177	113	2,270	600	1,088	3,646	460	0	-
4562300	MISC OTHER REV	301949	THIRD PARTY TRN O&M REV	SG	472	7	131	35	63	211	27	0	-
4562300	MISC OTHER REV	301951	NON-WHEELING SYS REV	SG	74	1	21	5	10	33	4	0	-
4562300	MISC OTHER REV	301955	OTHER REV WY REG KENNECOTT	WYP	120	-	-	-	120	-	-	-	-
4562300	MISC OTHER REV	302071	I/C Transmission O&M Revenue-Sierra Pac	SG	21	0	6	2	3	9	1	0	-
4562300	MISC OTHER REV	361000	STEAM SALES	SG	694	10	193	51	92	309	39	0	-
4562300	MISC OTHER REV	374400	Timber Sales - Utility Property	SG	27	0	7	2	4	12	1	0	-
4562300 Total					**18,836**	**237**	**4,863**	**1,252**	**2,390**	**7,634**	**960**	**1**	**1,499**
4562310	EIM - MISCELLANEOUS	308001	EIM Rev-Forecasting Fee: Pac to TC	SG	21	0	6	2	3	9	1	0	-
4562310 Total					**21**	**0**	**6**	**2**	**3**	**9**	**1**	**0**	**-**
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	IDU	1	-	-	-	-	-	1	-	-
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	SO	15	0	4	1	2	7	1	0	-
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	UT	2	-	-	-	-	2	-	-	-
4562400 Total					**17**	**0**	**4**	**1**	**2**	**8**	**2**	**0**	**-**
4562700	RNW ENRGY CRDT SALE	301943	Renewable Energy Credit Sales-Deferral	SG	(6,180)	(86)	(1,715)	(453)	(822)	(2,755)	(348)	(0)	-
4562700	RNW ENRGY CRDT SALE	301944	Renewable Energy Credit Sales-Estimate	SG	853	12	237	63	114	380	48	0	-
4562700	RNW ENRGY CRDT SALE	301945	Renewable Energy Credit Sales	SG	17,570	244	4,877	1,289	2,338	7,834	989	1	-
4562700	RNW ENRGY CRDT SALE	352943	Renwbl En Cr Sls-Amt	OTHER	2,646	-	-	-	-	-	-	-	2,646
4562700	RNW ENRGY CRDT SALE	352950	REC Sales - Wind Wake Loss Indemnity	SG	16	0	5	1	2	7	1	0	-
4562700	RNW ENRGY CRDT SALE	354943	REC Sales - Pryor Mtn - Deferral	OTHER	768	-	-	-	-	-	-	-	768
4562700	RNW ENRGY CRDT SALE	354945	REC Sales - Blue Sky Program - Actual	OTHER	6,533	-	-	-	-	-	-	-	6,533
4562700 Total					**22,207**	**170**	**3,403**	**899**	**1,631**	**5,466**	**690**	**0**	**9,947**

PACIFICORP

Electric Operations Revenue (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4562800	CA GHG Emission Allo	352001	CA GHG Allowance Revenues	OTHER	15,331	-	-	-	-	-	-	-	15,331
4562800	CA GHG Emission Allo	352002	CA GHG Allowance Revenues - Deferral	OTHER	(13,390)	-	-	-	-	-	-	-	(13,390)
4562800	CA GHG Emission Allo	352003	CA GHG Allowance Revenues – Amortz	OTHER	19,434	-	-	-	-	-	-	-	19,434
4562800	CA GHG Emission Allo	352004	CA GHG Allow Revenues - SOMAH Amortz	OTHER	120	-	-	-	-	-	-	-	120
4562800 Total					**21,496**	-	-	-	-	-	-	-	**21,496**
Grand Total					**7,121,689**	**144,886**	**1,928,672**	**496,819**	**861,612**	**3,017,244**	**407,715**	**16,954**	**247,787**

B2. O&M EXPENSE

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5000000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	16,167	224	4,487	1,186	2,151	7,208	910	1	-
5000000 Total					**16,167**	**224**	**4,487**	**1,186**	**2,151**	**7,208**	**910**	**1**	**-**
5001000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	681	9	189	50	91	303	38	0	-
5001000 Total					**681**	**9**	**189**	**50**	**91**	**303**	**38**	**0**	**-**
5010000	FUEL CONSUMED	NPCX	Net Power Cost Expense	SE	3,232	40	867	217	464	1,450	195	0	-
5010000 Total					**3,232**	**40**	**867**	**217**	**464**	**1,450**	**195**	**0**	**-**
5011000	FUEL CONSUMED-COAL	NPCX	Net Power Cost Expense	SE	625,266	7,817	167,714	41,944	89,669	280,460	37,632	31	-
5011000 Total					**625,266**	**7,817**	**167,714**	**41,944**	**89,669**	**280,460**	**37,632**	**31**	**-**
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	IDU	(360)	-	-	-	-	-	(360)	-	-
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	WYP	(972)	-	-	-	(972)	-	-	-	-
5011200 Total					**(1,333)**	**-**	**-**	**-**	**(972)**	**-**	**(360)**	**-**	**-**
5011300	FUEL-COAL DC UMWA PE	STEX	Steam O&M Expense	SE	2,845	36	763	191	408	1,276	171	0	-
5011300 Total					**2,845**	**36**	**763**	**191**	**408**	**1,276**	**171**	**0**	**-**
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	SE	(116)	(1)	(31)	(8)	(17)	(52)	(7)	(0)	-
5011500 Total					**(116)**	**(1)**	**(31)**	**(8)**	**(17)**	**(52)**	**(7)**	**(0)**	**-**
5012000	FUEL HAND-COAL	STEX	Steam O&M Expense	SE	9,661	121	2,591	648	1,385	4,333	581	0	-
5012000 Total					**9,661**	**121**	**2,591**	**648**	**1,385**	**4,333**	**581**	**0**	**-**
5013000	START UP FUEL - GAS	NPCX	Net Power Cost Expense	SE	351	4	94	24	50	157	21	0	-
5013000 Total					**351**	**4**	**94**	**24**	**50**	**157**	**21**	**0**	**-**
5013500	FUEL CONSUMED-GAS	NPCX	Net Power Cost Expense	SE	164,981	2,063	44,253	11,067	23,660	74,001	9,930	8	-
5013500 Total					**164,981**	**2,063**	**44,253**	**11,067**	**23,660**	**74,001**	**9,930**	**8**	**-**
5014000	FUEL CONSUMED-DIESEL	NPCX	Net Power Cost Expense	SE	2	0	1	0	0	1	0	0	-
5014000 Total					**2**	**0**	**1**	**0**	**0**	**1**	**0**	**0**	**-**
5014500	START UP FUEL-DIESEL	NPCX	Net Power Cost Expense	SE	6,167	77	1,654	414	884	2,766	371	0	-
5014500 Total					**6,167**	**77**	**1,654**	**414**	**884**	**2,766**	**371**	**0**	**-**
5015000	FUEL CONS-RES DISP	NPCX	Net Power Cost Expense	SE	19	0	5	1	3	8	1	0	-
5015000 Total					**19**	**0**	**5**	**1**	**3**	**8**	**1**	**0**	**-**
5015100	ASH & ASH BYPRD SALE	NPCX	Net Power Cost Expense	SE	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
5015100 Total					**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**-**
5020000	STEAM EXPENSES	STEX	Steam O&M Expense	SG	33,063	458	9,177	2,425	4,399	14,742	1,861	1	-
5020000 Total					**33,063**	**458**	**9,177**	**2,425**	**4,399**	**14,742**	**1,861**	**1**	**-**
5022000	STM EXP - FLYASH	STEX	Steam O&M Expense	SG	4,289	59	1,190	315	571	1,912	241	0	-
5022000 Total					**4,289**	**59**	**1,190**	**315**	**571**	**1,912**	**241**	**0**	**-**
5023000	STM EXP BOTTOM ASH	STEX	Steam O&M Expense	SG	335	5	93	25	45	149	19	0	-
5023000 Total					**335**	**5**	**93**	**25**	**45**	**149**	**19**	**0**	**-**
5024000	STM EXP SCRUBBER	STEX	Steam O&M Expense	SG	11,363	158	3,154	834	1,512	5,066	639	0	-
5024000 Total					**11,363**	**158**	**3,154**	**834**	**1,512**	**5,066**	**639**	**0**	**-**
5029000	STM EXP - OTHER	STEX	Steam O&M Expense	SG	19,757	274	5,484	1,449	2,629	8,809	1,112	1	-
5029000 Total					**19,757**	**274**	**5,484**	**1,449**	**2,629**	**8,809**	**1,112**	**1**	**-**
5030000	STEAM FRM OTH SRCS	NPCX	Net Power Cost Expense	SE	5,462	68	1,465	366	783	2,450	329	0	-
5030000 Total					**5,462**	**68**	**1,465**	**366**	**783**	**2,450**	**329**	**0**	**-**
5050000	ELECTRIC EXPENSES	STEX	Steam O&M Expense	SG	1,127	16	313	83	150	502	63	0	-
5050000 Total					**1,127**	**16**	**313**	**83**	**150**	**502**	**63**	**0**	**-**
5051000	ELEC EXP GENERAL	STEX	Steam O&M Expense	SG	17	0	5	1	2	8	1	0	-
5051000 Total					**17**	**0**	**5**	**1**	**2**	**8**	**1**	**0**	**-**
5060000	MISC STEAM PWR EXP	STEX	Steam O&M Expense	SG	70,863	982	19,668	5,198	9,428	31,595	3,988	3	-
5060000 Total					**70,863**	**982**	**19,668**	**5,198**	**9,428**	**31,595**	**3,988**	**3**	**-**
5061000	MISC STM EXP - CON	STEX	Steam O&M Expense	SG	1,085	15	301	80	144	484	61	0	-
5061000 Total					**1,085**	**15**	**301**	**80**	**144**	**484**	**61**	**0**	**-**
5061100	MISC STM EXP PLCLU	STEX	Steam O&M Expense	SG	1,410	20	391	103	188	629	79	0	-
5061100 Total					**1,410**	**20**	**391**	**103**	**188**	**629**	**79**	**0**	**-**

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5061200	MISC STM EXP UNMTG	STEX	Steam O&M Expense	SG	35	0	10	3	5	16	2	0	-
5061200 Total					**35**	**0**	**10**	**3**	**5**	**16**	**2**	**0**	**-**
5061300	MISC STM EXP COMPT	STEX	Steam O&M Expense	SG	492	7	137	36	66	220	28	0	-
5061300 Total					**492**	**7**	**137**	**36**	**66**	**220**	**28**	**0**	**-**
5061400	MISC STM EXP OFFIC	STEX	Steam O&M Expense	SG	1,490	21	414	109	198	665	84	0	-
5061400 Total					**1,490**	**21**	**414**	**109**	**198**	**665**	**84**	**0**	**-**
5061500	MISC STM EXP COMM	STEX	Steam O&M Expense	SG	149	2	41	11	20	66	8	0	-
5061500 Total					**149**	**2**	**41**	**11**	**20**	**66**	**8**	**0**	**-**
5061600	MISC STM EXP FIRE	STEX	Steam O&M Expense	SG	172	2	48	13	23	77	10	0	-
5061600 Total					**172**	**2**	**48**	**13**	**23**	**77**	**10**	**0**	**-**
5062000	MISC STM - ENVRMNT	STEX	Steam O&M Expense	SG	4,833	67	1,341	355	643	2,155	272	0	-
5062000 Total					**4,833**	**67**	**1,341**	**355**	**643**	**2,155**	**272**	**0**	**-**
5063000	MISC STEAM JVA CR	STEX	Steam O&M Expense	SG	(37,817)	(524)	(10,496)	(2,774)	(5,031)	(16,861)	(2,128)	(2)	-
5063000 Total					**(37,817)**	**(524)**	**(10,496)**	**(2,774)**	**(5,031)**	**(16,861)**	**(2,128)**	**(2)**	**-**
5064000	MISC STM EXP RCRT	STEX	Steam O&M Expense	SG	5	0	1	0	1	2	0	0	-
5064000 Total					**5**	**0**	**1**	**0**	**1**	**2**	**0**	**0**	**-**
5065000	MISC STM EXP - SEC	STEX	Steam O&M Expense	SG	793	11	220	58	105	354	45	0	-
5065000 Total					**793**	**11**	**220**	**58**	**105**	**354**	**45**	**0**	**-**
5066000	MISC STM EXP -SFTY	STEX	Steam O&M Expense	SG	1,003	14	278	74	133	447	56	0	-
5066000 Total					**1,003**	**14**	**278**	**74**	**133**	**447**	**56**	**0**	**-**
5067000	MISC STM EXP TRNNG	STEX	Steam O&M Expense	SG	2,934	41	814	215	390	1,308	165	0	-
5067000 Total					**2,934**	**41**	**814**	**215**	**390**	**1,308**	**165**	**0**	**-**
5069000	MISC STM EXP WTSPY	STEX	Steam O&M Expense	SG	1,685	23	468	124	224	751	95	0	-
5069000 Total					**1,685**	**23**	**468**	**124**	**224**	**751**	**95**	**0**	**-**
5069900	MISC STM EXP MISC	STEX	Steam O&M Expense	SG	3,939	55	1,093	289	524	1,756	222	0	-
5069900 Total					**3,939**	**55**	**1,093**	**289**	**524**	**1,756**	**222**	**0**	**-**
5070000	RENTS (STEAM GEN)	STEX	Steam O&M Expense	SG	537	7	149	39	72	240	30	0	-
5070000 Total					**537**	**7**	**149**	**39**	**72**	**240**	**30**	**0**	**-**
5090000	ALLOWANCES	STEX	Steam O&M Expense	SG	3,693	51	1,025	271	491	1,646	208	0	-
5090000	ALLOWANCES	STEX	Steam O&M Expense	SG	95	1	26	7	13	42	5	0	-
5090000	ALLOWANCES	STEX	Steam O&M Expense	SG	19,688	273	5,464	1,444	2,619	8,778	1,108	1	-
5090000	ALLOWANCES	STEX	Steam O&M Expense	SG	2,569	36	713	188	342	1,146	145	0	-
5090000	ALLOWANCES	STEX	Steam O&M Expense	SG	5,553	77	1,541	407	739	2,476	312	0	-
5090000	ALLOWANCES	STEX	Steam O&M Expense	SG	(5,553)	(77)	(1,541)	(407)	(739)	(2,476)	(312)	(0)	-
5090000 Total					**26,045**	**361**	**7,229**	**1,911**	**3,465**	**11,612**	**1,466**	**1**	**-**
5100000	MNT SUPERV & ENG	STEX	Steam O&M Expense	SG	1,505	21	418	110	200	671	85	0	-
5100000 Total					**1,505**	**21**	**418**	**110**	**200**	**671**	**85**	**0**	**-**
5101000	MNTNCE SUPVSN &ENG	STEX	Steam O&M Expense	SG	2,474	34	687	181	329	1,103	139	0	-
5101000 Total					**2,474**	**34**	**687**	**181**	**329**	**1,103**	**139**	**0**	**-**
5110000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	2,190	30	608	161	291	977	123	0	-
5110000 Total					**2,190**	**30**	**608**	**161**	**291**	**977**	**123**	**0**	**-**
5111000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	3,834	53	1,064	281	510	1,709	216	0	-
5111000 Total					**3,834**	**53**	**1,064**	**281**	**510**	**1,709**	**216**	**0**	**-**
5111100	MNT STRCT PMP PLNT	STEX	Steam O&M Expense	SG	1,219	17	338	89	162	544	69	0	-
5111100 Total					**1,219**	**17**	**338**	**89**	**162**	**544**	**69**	**0**	**-**
5111200	MNT STRCT WASTE WT	STEX	Steam O&M Expense	SG	872	12	242	64	116	389	49	0	-
5111200 Total					**872**	**12**	**242**	**64**	**116**	**389**	**49**	**0**	**-**
5112000	STRUCTURAL SYSTEMS	STEX	Steam O&M Expense	SG	8,487	118	2,356	623	1,129	3,784	478	0	-
5112000 Total					**8,487**	**118**	**2,356**	**623**	**1,129**	**3,784**	**478**	**0**	**-**
5114000	MNT OF STRCT CATH	STEX	Steam O&M Expense	SG	31	0	9	2	4	14	2	0	-
5114000 Total					**31**	**0**	**9**	**2**	**4**	**14**	**2**	**0**	**-**

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Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5116000	MNT STRCT DAM RIVR	STEX	Steam O&M Expense	SG	76	1	21	6	10	34	4	0	-
5116000 Total					**76**	**1**	**21**	**6**	**10**	**34**	**4**	**0**	**-**
5117000	MNT STRCT FIRE PRT	STEX	Steam O&M Expense	SG	1,885	26	523	138	251	840	106	0	-
5117000 Total					**1,885**	**26**	**523**	**138**	**251**	**840**	**106**	**0**	**-**
5118000	MNT STRCT-GROUNDS	STEX	Steam O&M Expense	SG	672	9	187	49	89	300	38	0	-
5118000 Total					**672**	**9**	**187**	**49**	**89**	**300**	**38**	**0**	**-**
5119000	MNT OF STRCT-HVAC	STEX	Steam O&M Expense	SG	2,195	30	609	161	292	979	124	0	-
5119000 Total					**2,195**	**30**	**609**	**161**	**292**	**979**	**124**	**0**	**-**
5119900	MNT OF STRCT-MISC	STEX	Steam O&M Expense	SG	683	9	190	50	91	305	38	0	-
5119900 Total					**683**	**9**	**190**	**50**	**91**	**305**	**38**	**0**	**-**
5120000	MANT OF BOILR PLNT	STEX	Steam O&M Expense	SG	9,846	136	2,733	722	1,310	4,390	554	0	-
5120000 Total					**9,846**	**136**	**2,733**	**722**	**1,310**	**4,390**	**554**	**0**	**-**
5121000	MNT BOILR-AIR HTR	STEX	Steam O&M Expense	SG	12,925	179	3,587	948	1,720	5,763	727	1	-
5121000 Total					**12,925**	**179**	**3,587**	**948**	**1,720**	**5,763**	**727**	**1**	**-**
5121100	MNT BOILR-CHEM FD	STEX	Steam O&M Expense	SG	211	3	59	15	28	94	12	0	-
5121100 Total					**211**	**3**	**59**	**15**	**28**	**94**	**12**	**0**	**-**
5121200	MNT BOILR-CL HANDL	STEX	Steam O&M Expense	SG	4,613	64	1,280	338	614	2,057	260	0	-
5121200 Total					**4,613**	**64**	**1,280**	**338**	**614**	**2,057**	**260**	**0**	**-**
5121400	MNT BOIL-DEMINERLZ	STEX	Steam O&M Expense	SG	369	5	102	27	49	165	21	0	-
5121400 Total					**369**	**5**	**102**	**27**	**49**	**165**	**21**	**0**	**-**
5121500	MNT BOIL-EXTRC STM	STEX	Steam O&M Expense	SG	792	11	220	58	105	353	45	0	-
5121500 Total					**792**	**11**	**220**	**58**	**105**	**353**	**45**	**0**	**-**
5121600	MNT BOILR-FLYASH	STEX	Steam O&M Expense	SG	3,027	42	840	222	403	1,350	170	0	-
5121600 Total					**3,027**	**42**	**840**	**222**	**403**	**1,350**	**170**	**0**	**-**
5121700	MNT BOIL-FUEL OIL	STEX	Steam O&M Expense	SG	731	10	203	54	97	326	41	0	-
5121700 Total					**731**	**10**	**203**	**54**	**97**	**326**	**41**	**0**	**-**
5121800	MNT BOIL-FEEDWATR	STEX	Steam O&M Expense	SG	3,751	52	1,041	275	499	1,672	211	0	-
5121800 Total					**3,751**	**52**	**1,041**	**275**	**499**	**1,672**	**211**	**0**	**-**
5121900	MNT BOIL-FRZ PRTEC	STEX	Steam O&M Expense	SG	27	0	8	2	4	12	2	0	-
5121900 Total					**27**	**0**	**8**	**2**	**4**	**12**	**2**	**0**	**-**
5122000	MNT BOILR-AUX SYST	STEX	Steam O&M Expense	SG	559	8	155	41	74	249	31	0	-
5122000 Total					**559**	**8**	**155**	**41**	**74**	**249**	**31**	**0**	**-**
5122100	MNT BOILR-MAIN STM	STEX	Steam O&M Expense	SG	879	12	244	64	117	392	49	0	-
5122100 Total					**879**	**12**	**244**	**64**	**117**	**392**	**49**	**0**	**-**
5122200	MNT BOIL-PLVRZD CL	STEX	Steam O&M Expense	SG	7,444	103	2,066	546	990	3,319	419	0	-
5122200 Total					**7,444**	**103**	**2,066**	**546**	**990**	**3,319**	**419**	**0**	**-**
5122300	MNT BOIL-PRECIP/BAG	STEX	Steam O&M Expense	SG	2,972	41	825	218	395	1,325	167	0	-
5122300 Total					**2,972**	**41**	**825**	**218**	**395**	**1,325**	**167**	**0**	**-**
5122400	MNT BOIL-PRTRT WTR	STEX	Steam O&M Expense	SG	649	9	180	48	86	289	37	0	-
5122400 Total					**649**	**9**	**180**	**48**	**86**	**289**	**37**	**0**	**-**
5122500	MNT BOIL-RV OSMSIS	STEX	Steam O&M Expense	SG	156	2	43	11	21	70	9	0	-
5122500 Total					**156**	**2**	**43**	**11**	**21**	**70**	**9**	**0**	**-**
5122600	MNT BOIL-RHEAT ST	STEX	Steam O&M Expense	SG	178	2	49	13	24	79	10	0	-
5122600 Total					**178**	**2**	**49**	**13**	**24**	**79**	**10**	**0**	**-**
5122800	MNT BOIL-SOOTBLWG	STEX	Steam O&M Expense	SG	1,411	20	392	103	188	629	79	0	-
5122800 Total					**1,411**	**20**	**392**	**103**	**188**	**629**	**79**	**0**	**-**
5122900	MNT BOILR-SCRUBBER	STEX	Steam O&M Expense	SG	6,208	86	1,723	455	826	2,768	349	0	-
5122900 Total					**6,208**	**86**	**1,723**	**455**	**826**	**2,768**	**349**	**0**	**-**
5123000	MNT BOILR-BOTM ASH	STEX	Steam O&M Expense	SG	2,055	28	570	151	273	916	116	0	-
5123000 Total					**2,055**	**28**	**570**	**151**	**273**	**916**	**116**	**0**	**-**
5123100	MNT BOIL-WTR TRTMT	STEX	Steam O&M Expense	SG	679	9	188	50	90	303	38	0	-

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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5123100 Total					**679**	**9**	**188**	**50**	**90**	**303**	**38**	**0**	**-**
5123200	MNT BOIL-CNTL SUPT	STEX	Steam O&M Expense	SG	589	8	164	43	78	263	33	0	-
5123200 Total					**589**	**8**	**164**	**43**	**78**	**263**	**33**	**0**	**-**
5123300	MAINT GEO GATH SYS	STEX	Steam O&M Expense	SG	85	1	24	6	11	38	5	0	-
5123300 Total					**85**	**1**	**24**	**6**	**11**	**38**	**5**	**0**	**-**
5123400	MAINT OF BOILERS	STEX	Steam O&M Expense	SG	1,817	25	504	133	242	810	102	0	-
5123400 Total					**1,817**	**25**	**504**	**133**	**242**	**810**	**102**	**0**	**-**
5124000	MNT BOILR-CONTROLS	STEX	Steam O&M Expense	SG	798	11	222	59	106	356	45	0	-
5124000 Total					**798**	**11**	**222**	**59**	**106**	**356**	**45**	**0**	**-**
5125000	MNT BOILER-DRAFT	STEX	Steam O&M Expense	SG	2,518	35	699	185	335	1,123	142	0	-
5125000 Total					**2,518**	**35**	**699**	**185**	**335**	**1,123**	**142**	**0**	**-**
5126000	MNT BOILR-FIRESIDE	STEX	Steam O&M Expense	SG	1,467	20	407	108	195	654	83	0	-
5126000 Total					**1,467**	**20**	**407**	**108**	**195**	**654**	**83**	**0**	**-**
5127000	MNT BLR-BEARNG WTR	STEX	Steam O&M Expense	SG	262	4	73	19	35	117	15	0	-
5127000 Total					**262**	**4**	**73**	**19**	**35**	**117**	**15**	**0**	**-**
5128000	MNT BOILR WTR/STMD	STEX	Steam O&M Expense	SG	8,399	116	2,331	616	1,117	3,745	473	0	-
5128000 Total					**8,399**	**116**	**2,331**	**616**	**1,117**	**3,745**	**473**	**0**	**-**
5129000	MNT BOIL-COMP AIR	STEX	Steam O&M Expense	SG	570	8	158	42	76	254	32	0	-
5129000 Total					**570**	**8**	**158**	**42**	**76**	**254**	**32**	**0**	**-**
5129900	MAINT BOILER-MISC	STEX	Steam O&M Expense	SG	207	3	57	15	28	92	12	0	-
5129900 Total					**207**	**3**	**57**	**15**	**28**	**92**	**12**	**0**	**-**
5130000	MAINT ELEC PLANT	STEX	Steam O&M Expense	SG	1,786	25	496	131	238	796	100	0	-
5130000 Total					**1,786**	**25**	**496**	**131**	**238**	**796**	**100**	**0**	**-**
5131000	MAINT ELEC AC	STEX	Steam O&M Expense	SG	19,631	272	5,449	1,440	2,612	8,753	1,105	1	-
5131000 Total					**19,631**	**272**	**5,449**	**1,440**	**2,612**	**8,753**	**1,105**	**1**	**-**
5131001	MAINT COMP HW-STEAM	STEX	Steam O&M Expense	SG	2	0	0	0	0	1	0	0	-
5131001 Total					**2**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**-**
5131100	MAINT/LUBE-OIL SYS	STEX	Steam O&M Expense	SG	962	13	267	71	128	429	54	0	-
5131100 Total					**962**	**13**	**267**	**71**	**128**	**429**	**54**	**0**	**-**
5131300	MAINT/PREVENT ROUT	STEX	Steam O&M Expense	SG	5	0	1	0	1	2	0	0	-
5131300 Total					**5**	**0**	**1**	**0**	**1**	**2**	**0**	**0**	**-**
5131400	MAINT/MAIN TURBINE	STEX	Steam O&M Expense	SG	8,557	119	2,375	628	1,138	3,815	482	0	-
5131400 Total					**8,557**	**119**	**2,375**	**628**	**1,138**	**3,815**	**482**	**0**	**-**
5132000	MAINT ALARMS/INFO	STEX	Steam O&M Expense	SG	1,635	23	454	120	217	729	92	0	-
5132000 Total					**1,635**	**23**	**454**	**120**	**217**	**729**	**92**	**0**	**-**
5132002	MAINT COMP SW-STEAM	STEX	Steam O&M Expense	SG	399	6	111	29	53	178	22	0	-
5132002 Total					**399**	**6**	**111**	**29**	**53**	**178**	**22**	**0**	**-**
5133000	MAINT/AIR-COOL-CON	STEX	Steam O&M Expense	SG	153	2	42	11	20	68	9	0	-
5133000 Total					**153**	**2**	**42**	**11**	**20**	**68**	**9**	**0**	**-**
5133003	MAINT COMM EQP-STEAM	STEX	Steam O&M Expense	SG	152	2	42	11	20	68	9	0	-
5133003 Total					**152**	**2**	**42**	**11**	**20**	**68**	**9**	**0**	**-**
5134000	MAINT/COMPNT COOL	STEX	Steam O&M Expense	SG	86	1	24	6	11	39	5	0	-
5134000 Total					**86**	**1**	**24**	**6**	**11**	**39**	**5**	**0**	**-**
5135000	MAINT/COMPNT AUXIL	STEX	Steam O&M Expense	SG	1,196	17	332	88	159	533	67	0	-
5135000 Total					**1,196**	**17**	**332**	**88**	**159**	**533**	**67**	**0**	**-**
5137000	MAINT-COOLING TOWR	STEX	Steam O&M Expense	SG	2,137	30	593	157	284	953	120	0	-
5137000 Total					**2,137**	**30**	**593**	**157**	**284**	**953**	**120**	**0**	**-**
5138000	MAINT-CIRCUL WATER	STEX	Steam O&M Expense	SG	2,218	31	616	163	295	989	125	0	-
5138000 Total					**2,218**	**31**	**616**	**163**	**295**	**989**	**125**	**0**	**-**
5139000	MAINT-ELECT - DC	STEX	Steam O&M Expense	SG	372	5	103	27	50	166	21	0	-
5139000 Total					**372**	**5**	**103**	**27**	**50**	**166**	**21**	**0**	**-**

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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5139900	MNT ELEC PLT-MISC	STEX	Steam O&M Expense	SG	31	0	9	2	4	14	2	0	-
5139900 Total					**31**	**0**	**9**	**2**	**4**	**14**	**2**	**0**	**-**
5140000	MAINT MISC STM PLN	STEX	Steam O&M Expense	SG	2,465	34	684	181	328	1,099	139	0	-
5140000 Total					**2,465**	**34**	**684**	**181**	**328**	**1,099**	**139**	**0**	**-**
5141000	MISC STM-COMP AIR	STEX	Steam O&M Expense	SG	954	13	265	70	127	426	54	0	-
5141000 Total					**954**	**13**	**265**	**70**	**127**	**426**	**54**	**0**	**-**
5142000	MISC STM PLT-CONSU	STEX	Steam O&M Expense	SG	529	7	147	39	70	236	30	0	-
5142000 Total					**529**	**7**	**147**	**39**	**70**	**236**	**30**	**0**	**-**
5144000	MISC STM PLNT-LAB	STEX	Steam O&M Expense	SG	362	5	101	27	48	162	20	0	-
5144000 Total					**362**	**5**	**101**	**27**	**48**	**162**	**20**	**0**	**-**
5145000	MAINT MISC-SM TOOL	STEX	Steam O&M Expense	SG	971	13	269	71	129	433	55	0	-
5145000 Total					**971**	**13**	**269**	**71**	**129**	**433**	**55**	**0**	**-**
5146000	MAINT/PAGING SYS	STEX	Steam O&M Expense	SG	110	2	30	8	15	49	6	0	-
5146000 Total					**110**	**2**	**30**	**8**	**15**	**49**	**6**	**0**	**-**
5147000	MAINT/PLANT EQUIP	STEX	Steam O&M Expense	SG	2,205	31	612	162	293	983	124	0	-
5147000 Total					**2,205**	**31**	**612**	**162**	**293**	**983**	**124**	**0**	**-**
5148000	MAINT/PLT-VEHICLES	STEX	Steam O&M Expense	SG	2,103	29	584	154	280	938	118	0	-
5148000 Total					**2,103**	**29**	**584**	**154**	**280**	**938**	**118**	**0**	**-**
5149000	MAINT MISC-OTHER	STEX	Steam O&M Expense	SG	463	6	129	34	62	207	26	0	-
5149000 Total					**463**	**6**	**129**	**34**	**62**	**207**	**26**	**0**	**-**
5149500	MAINT STM PLT-ENV AM	STEX	Steam O&M Expense	SG	4,981	69	1,382	365	663	2,221	280	0	-
5149500 Total					**4,981**	**69**	**1,382**	**365**	**663**	**2,221**	**280**	**0**	**-**
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	9,488	132	2,633	696	1,262	4,230	534	0	-
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-U	3,525	49	978	259	469	1,571	198	0	-
5350000 Total					**13,012**	**180**	**3,612**	**955**	**1,731**	**5,802**	**732**	**1**	**-**
5360000	WATER FOR POWER	HYEX	Hydro O&M Expense	SG-P	(134)	(2)	(37)	(10)	(18)	(60)	(8)	(0)	-
5360000 Total					**(134)**	**(2)**	**(37)**	**(10)**	**(18)**	**(60)**	**(8)**	**(0)**	**-**
5370000	HYDRAULIC EXPENSES	HYEX	Hydro O&M Expense	SG-P	3,343	46	928	245	445	1,490	188	0	-
5370000 Total					**3,343**	**46**	**928**	**245**	**445**	**1,490**	**188**	**0**	**-**
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-P	678	9	188	50	90	302	38	0	-
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-U	127	2	35	9	17	56	7	0	-
5371000 Total					**804**	**11**	**223**	**59**	**107**	**359**	**45**	**0**	**-**
5372000	HYDRO/HATCHERY EXP	HYEX	Hydro O&M Expense	SG-P	212	3	59	16	28	95	12	0	-
5372000 Total					**212**	**3**	**59**	**16**	**28**	**95**	**12**	**0**	**-**
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	191	3	53	14	25	85	11	0	-
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-U	60	1	17	4	8	27	3	0	-
5374000 Total					**251**	**3**	**70**	**18**	**33**	**112**	**14**	**0**	**-**
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-P	975	14	271	72	130	435	55	0	-
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-U	194	3	54	14	26	86	11	0	-
5379000 Total					**1,169**	**16**	**325**	**86**	**156**	**521**	**66**	**0**	**-**
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-P	9,041	125	2,509	663	1,203	4,031	509	0	-
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-U	9,588	133	2,661	703	1,276	4,275	540	0	-
5390000 Total					**18,629**	**258**	**5,171**	**1,367**	**2,479**	**8,306**	**1,048**	**1**	**-**
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-P	1,567	22	435	115	208	699	88	0	-
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-U	112	2	31	8	15	50	6	0	-
5400000 Total					**1,679**	**23**	**466**	**123**	**223**	**748**	**94**	**0**	**-**
5410000	MNT SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	0	0	0	0	0	0	0	0	-
5410000 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-**
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-P	476	7	132	35	63	212	27	0	-
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-U	49	1	14	4	7	22	3	0	-
5420000 Total					**525**	**7**	**146**	**39**	**70**	**234**	**30**	**0**	**-**

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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-P	439	6	122	32	58	196	25	0	-
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-U	637	9	177	47	85	284	36	0	-
5430000 Total					**1,076**	**15**	**299**	**79**	**143**	**480**	**61**	**0**	**-**
5440000	MAINT OF ELEC PLNT	HYEX	Hydro O&M Expense	SG-U	92	1	25	7	12	41	5	0	-
5440000 Total					**92**	**1**	**25**	**7**	**12**	**41**	**5**	**0**	**-**
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-P	531	7	147	39	71	237	30	0	-
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-U	92	1	26	7	12	41	5	0	-
5441000 Total					**623**	**9**	**173**	**46**	**83**	**278**	**35**	**0**	**-**
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-P	340	5	94	25	45	151	19	0	-
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-U	501	7	139	37	67	223	28	0	-
5442000 Total					**841**	**12**	**233**	**62**	**112**	**375**	**47**	**0**	**-**
5443000	MAINT COMM EQP-HYDR(	HYEX	Hydro O&M Expense	SG-P	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
5443000	MAINT COMM EQP-HYDR(	HYEX	Hydro O&M Expense	SG-U	0	0	0	0	0	0	0	0	-
5443000 Total					**(1)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**-**
5450000	MNT MISC HYDRO PLT	HYEX	Hydro O&M Expense	SG-P	10	0	3	1	1	5	1	0	-
5450000 Total					**10**	**0**	**3**	**1**	**1**	**5**	**1**	**0**	**-**
5451000	MNT-FISH/WILDLIFE	HYEX	Hydro O&M Expense	SG-P	951	13	264	70	127	424	54	0	-
5451000 Total					**951**	**13**	**264**	**70**	**127**	**424**	**54**	**0**	**-**
5454000	MAINT-OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	0	0	0	0	0	0	0	0	-
5454000 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-**
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-P	343	5	95	25	46	153	19	0	-
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-U	390	5	108	29	52	174	22	0	-
5455000 Total					**734**	**10**	**204**	**54**	**98**	**327**	**41**	**0**	**-**
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG	3,436	48	954	252	457	1,532	193	0	-
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-P	2,025	28	562	149	269	903	114	0	-
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-U	521	7	144	38	69	232	29	0	-
5459000 Total					**5,982**	**83**	**1,660**	**439**	**796**	**2,667**	**337**	**0**	**-**
5459500	MAINT OF HYDRO PLT-E	HYEX	Hydro O&M Expense	SG-P	1,038	14	288	76	138	463	58	0	-
5459500 Total					**1,038**	**14**	**288**	**76**	**138**	**463**	**58**	**0**	**-**
5460000	OPER SUPERV & ENG	OPEX	Other Production O&M Expense	SG	461	6	128	34	61	205	26	0	-
5460000 Total					**461**	**6**	**128**	**34**	**61**	**205**	**26**	**0**	**-**
5471000	NATURAL GAS	NPCX	Net Power Cost Expense	SE	394,477	4,932	105,810	26,462	56,572	176,940	23,742	19	-
5471000 Total					**394,477**	**4,932**	**105,810**	**26,462**	**56,572**	**176,940**	**23,742**	**19**	**-**
5480000	GENERATION EXP	OPEX	Other Production O&M Expense	SG	29,537	409	8,198	2,167	3,930	13,170	1,662	1	-
5480000 Total					**29,537**	**409**	**8,198**	**2,167**	**3,930**	**13,170**	**1,662**	**1**	**-**
5490000	MIS OTH PWR GEN EX	OPEX	Other Production O&M Expense	OR	20	-	20	-	-	-	-	-	-
5490000	MIS OTH PWR GEN EX	OPEX	Other Production O&M Expense	SG	7,866	109	2,183	577	1,046	3,507	443	0	-
5490000 Total					**7,886**	**109**	**2,203**	**577**	**1,046**	**3,507**	**443**	**0**	**-**
5500000	RENTS (OTHER GEN)	OPEX	Other Production O&M Expense	OR	185	-	185	-	-	-	-	-	-
5500000	RENTS (OTHER GEN)	OPEX	Other Production O&M Expense	SG	3,586	50	995	263	477	1,599	202	0	-
5500000 Total					**3,771**	**50**	**1,180**	**263**	**477**	**1,599**	**202**	**0**	**-**
5520000	MAINT OF STRUCTURE	OPEX	Other Production O&M Expense	SG	2,889	40	802	212	384	1,288	163	0	-
5520000 Total					**2,889**	**40**	**802**	**212**	**384**	**1,288**	**163**	**0**	**-**
5530000	MNT GEN & ELEC PLT	OPEX	Other Production O&M Expense	SG	23,312	323	6,470	1,710	3,102	10,394	1,312	1	-
5530000 Total					**23,312**	**323**	**6,470**	**1,710**	**3,102**	**10,394**	**1,312**	**1**	**-**
5531000	MNT COMP HW-OTR PRO(	OPEX	Other Production O&M Expense	SG	0	0	0	0	0	0	0	0	-
5531000 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-**
5532002	MNT COMP SW-OTR PRO(	OPEX	Other Production O&M Expense	SG	113	2	31	8	15	51	6	0	-
5532002 Total					**113**	**2**	**31**	**8**	**15**	**51**	**6**	**0**	**-**
5533003	MNT COMM EQP-OTR PR(	OPEX	Other Production O&M Expense	SG	27	0	7	2	4	12	2	0	-
5533003 Total					**27**	**0**	**7**	**2**	**4**	**12**	**2**	**0**	**-**

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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5540000	MNT MSC OTH PWR GN	OPEX	Other Production O&M Expense	SG	3,938	55	1,093	289	524	1,756	222	0	-
5540000 Total					**3,938**	**55**	**1,093**	**289**	**524**	**1,756**	**222**	**0**	**-**
5546000	MISC PLANT EQUIP	OPEX	Other Production O&M Expense	SG	22	0	6	2	3	10	1	0	-
5546000 Total					**22**	**0**	**6**	**2**	**3**	**10**	**1**	**0**	**-**
5549500	MAINT OF OTH PWR PLT	OPEX	Other Production O&M Expense	SG	1,938	27	538	142	258	864	109	0	-
5549500 Total					**1,938**	**27**	**538**	**142**	**258**	**864**	**109**	**0**	**-**
5550000	PURCHASED POWER	PSEX	Power Supply Expense	SG	1,101	15	306	81	147	491	62	0	-
5550000 Total					**1,101**	**15**	**306**	**81**	**147**	**491**	**62**	**0**	**-**
5552400	RENEW ENRGY CR PURC	NPCX	Net Power Cost Expense	OTHER	6,772	-	-	-	-	-	-	-	6,772
5552400 Total					**6,772**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**6,772**
5552500	OTH/INT/REC/DEL	NPCX	Net Power Cost Expense	SE	(18,915)	(236)	(5,074)	(1,269)	(2,713)	(8,484)	(1,138)	(1)	-
5552500 Total					**(18,915)**	**(236)**	**(5,074)**	**(1,269)**	**(2,713)**	**(8,484)**	**(1,138)**	**(1)**	**-**
5552700	PURCH POWER-UT SITUS	NPCX	Net Power Cost Expense	UT	19,829	-	-	-	-	19,829	-	-	-
5552700 Total					**19,829**	**-**	**-**	**-**	**-**	**19,829**	**-**	**-**	**-**
5552800	PURCH POWER-OR SITUS	NPCX	Net Power Cost Expense	OR	869	-	869	-	-	-	-	-	-
5552800 Total					**869**	**-**	**869**	**-**	**-**	**-**	**-**	**-**	**-**
5552900	PURCH POWER-CA SITUS	NPCX	Net Power Cost Expense	CA	183	183	-	-	-	-	-	-	-
5552900 Total					**183**	**183**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
5555700	NPC Deferral Mchnsm	NPCX	Net Power Cost Expense	OTHER	279,192	-	-	-	-	-	-	-	279,192
5555700 Total					**279,192**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**279,192**
5555900	Short-Term Firm Whls	NPCX	Net Power Cost Expense	SG	772,745	10,712	214,480	56,686	102,811	344,542	43,484	31	-
5555900 Total					**772,745**	**10,712**	**214,480**	**56,686**	**102,811**	**344,542**	**43,484**	**31**	**-**
5556300	FIRM ENERGY PURCH	NPCX	Net Power Cost Expense	SG	528,832	7,331	146,780	38,793	70,359	235,789	29,758	22	-
5556300 Total					**528,832**	**7,331**	**146,780**	**38,793**	**70,359**	**235,789**	**29,758**	**22**	**-**
5556400	FIRM DEMAND PURCH	NPCX	Net Power Cost Expense	SG	13,237	183	3,674	971	1,761	5,902	745	1	-
5556400 Total					**13,237**	**183**	**3,674**	**971**	**1,761**	**5,902**	**745**	**1**	**-**
5556700	POST-MERG FIRM PUR	NPCX	Net Power Cost Expense	SG	27,927	387	7,751	2,049	3,716	12,452	1,572	1	-
5556700 Total					**27,927**	**387**	**7,751**	**2,049**	**3,716**	**12,452**	**1,572**	**1**	**-**
5556710	EIM - FIRM PURCHASES	NPCX	Net Power Cost Expense	SG	(82,301)	(1,141)	(22,843)	(6,037)	(10,950)	(36,695)	(4,631)	(3)	-
5556710 Total					**(82,301)**	**(1,141)**	**(22,843)**	**(6,037)**	**(10,950)**	**(36,695)**	**(4,631)**	**(3)**	**-**
5560000	SYS CTRL & LD DISP	PSEX	Power Supply Expense	SG	3,307	46	918	243	440	1,474	186	0	-
5560000 Total					**3,307**	**46**	**918**	**243**	**440**	**1,474**	**186**	**0**	**-**
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SE	8	0	2	1	1	4	1	0	-
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SG	48,563	673	13,479	3,562	6,461	21,653	2,733	2	-
5570000 Total					**48,571**	**673**	**13,481**	**3,563**	**6,462**	**21,656**	**2,733**	**2**	**-**
5579000	OTH EXP-ST SITUS ACT	PSEX	Power Supply Expense	IDU	4,122	-	-	-	-	-	4,122	-	-
5579000	OTH EXP-ST SITUS ACT	PSEX	Power Supply Expense	OR	11,881	-	11,881	-	-	-	-	-	-
5579000 Total					**16,003**	**-**	**11,881**	**-**	**-**	**-**	**4,122**	**-**	**-**
5579100	OTH EXP-LIQ DAMAGE	PSEX	Power Supply Expense	UT	35	-	-	-	-	35	-	-	-
5579100	OTH EXP-LIQ DAMAGE	PSEX	Power Supply Expense	WYU	62	-	-	-	62	-	-	-	-
5579100 Total					**97**	**-**	**-**	**-**	**62**	**35**	**-**	**-**	**-**
5581300	OPER SUPERV & ENG	PSEX	Power Supply Expense	SG	10	0	3	1	1	5	1	0	-
5581300 Total					**10**	**0**	**3**	**1**	**1**	**5**	**1**	**0**	**-**
5581400	WIND TRBN & OTR OP	PSEX	Power Supply Expense	SG	1,532	21	425	112	204	683	86	0	-
5581400 Total					**1,532**	**21**	**425**	**112**	**204**	**683**	**86**	**0**	**-**
5581600	RENTS (WIND GEN)	PSEX	Power Supply Expense	SG	1,818	25	505	133	242	810	102	0	-
5581600 Total					**1,818**	**25**	**505**	**133**	**242**	**810**	**102**	**0**	**-**
5581900	MNT WND TRB/STRC/EQP	PSEX	Power Supply Expense	SG	2,814	39	781	206	374	1,255	158	0	-
5581900 Total					**2,814**	**39**	**781**	**206**	**374**	**1,255**	**158**	**0**	**-**
5582000	MAINT COMP HW-WIND	PSEX	Power Supply Expense	SG	0	0	0	0	0	0	0	0	-
5582000 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-**

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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5582002	SLR PANEL & OTHR OP	PSEX	Power Supply Expense	OR	149	-	149	-	-	-	-	-	-
5582002 Total					**149**	**-**	**149**	**-**	**-**	**-**	**-**	**-**	**-**
5582200	MAINT COMM EQP-WIND	PSEX	Power Supply Expense	SG	(127)	(2)	(35)	(9)	(17)	(57)	(7)	(0)	-
5582200 Total					**(127)**	**(2)**	**(35)**	**(9)**	**(17)**	**(57)**	**(7)**	**(0)**	**-**
5582300	MAINT MISC WIND GEN	PSEX	Power Supply Expense	SG	21,573	299	5,988	1,582	2,870	9,619	1,214	1	-
5582300 Total					**21,573**	**299**	**5,988**	**1,582**	**2,870**	**9,619**	**1,214**	**1**	**-**
5584000	RENTS (SOLAR GEN)	PSEX	Power Supply Expense	OR	59	-	59	-	-	-	-	-	-
5584000 Total					**59**	**-**	**59**	**-**	**-**	**-**	**-**	**-**	**-**
5591000	MNT EL EQ (OTR RENW)	PSEX	Power Supply Expense	SG	133	2	37	10	18	60	8	0	-
5591000 Total					**133**	**2**	**37**	**10**	**18**	**60**	**8**	**0**	**-**
5591001	OPER SUPERV & ENG	PSEX	Power Supply Expense	SG	1	0	0	0	0	1	0	0	-
5591001 Total					**1**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**-**
5591300	MNT COMP SW-OTR REN	PSEX	Power Supply Expense	SG	339	5	94	25	45	151	19	0	-
5591300 Total					**339**	**5**	**94**	**25**	**45**	**151**	**19**	**0**	**-**
5591400	MNT COM EQP-OTR REN	PSEX	Power Supply Expense	SG	2	0	1	0	0	1	0	0	-
5591400 Total					**2**	**0**	**1**	**0**	**0**	**1**	**0**	**0**	**-**
5591500	MAINT MISC OTR RENEW	PSEX	Power Supply Expense	SG	55	1	15	4	7	25	3	0	-
5591500 Total					**55**	**1**	**15**	**4**	**7**	**25**	**3**	**0**	**-**
5592000	OTHR RENEW MISC & OP	PSEX	Power Supply Expense	SG	345	5	96	25	46	154	19	0	-
5592000 Total					**345**	**5**	**96**	**25**	**46**	**154**	**19**	**0**	**-**
5593000	FUEL (OTHER RENEW)	PSEX	Power Supply Expense	SG	423	6	117	31	56	188	24	0	-
5593000 Total					**423**	**6**	**117**	**31**	**56**	**188**	**24**	**0**	**-**
5597000	MNT STRCT (OTR RENW)	PSEX	Power Supply Expense	SG	110	2	30	8	15	49	6	0	-
5597000 Total					**110**	**2**	**30**	**8**	**15**	**49**	**6**	**0**	**-**
5599000	MNT BOILR (OTR RENW)	PSEX	Power Supply Expense	SG	75	1	21	6	10	33	4	0	-
5599000 Total					**75**	**1**	**21**	**6**	**10**	**33**	**4**	**0**	**-**
5600000	OPER SUPERV & ENG	TNEX	Transmission O&M Expense	SG	14,011	194	3,889	1,028	1,864	6,247	788	1	-
5600000 Total					**14,011**	**194**	**3,889**	**1,028**	**1,864**	**6,247**	**788**	**1**	**-**
5612000	LD - MONITOR & OPER	TNEX	Transmission O&M Expense	SG	9,176	127	2,547	673	1,221	4,091	516	0	-
5612000 Total					**9,176**	**127**	**2,547**	**673**	**1,221**	**4,091**	**516**	**0**	**-**
5614000	SCHED, SYS CTR & DSP	TNEX	Transmission O&M Expense	SG	227	3	63	17	30	101	13	0	-
5614000 Total					**227**	**3**	**63**	**17**	**30**	**101**	**13**	**0**	**-**
5614010	EIM - SCHEDULING,SYS	TNEX	Transmission O&M Expense	SG	636	9	177	47	85	284	36	0	-
5614010 Total					**636**	**9**	**177**	**47**	**85**	**284**	**36**	**0**	**-**
5615000	REL PLAN & STDS DEV	TNEX	Transmission O&M Expense	SG	2,311	32	641	170	307	1,030	130	0	-
5615000 Total					**2,311**	**32**	**641**	**170**	**307**	**1,030**	**130**	**0**	**-**
5616000	TRANS SVC STUDIES	TNEX	Transmission O&M Expense	SG	223	3	62	16	30	99	13	0	-
5616000 Total					**223**	**3**	**62**	**16**	**30**	**99**	**13**	**0**	**-**
5617000	GEN INTERCNCT STUD	TNEX	Transmission O&M Expense	SG	2,419	34	672	177	322	1,079	136	0	-
5617000 Total					**2,419**	**34**	**672**	**177**	**322**	**1,079**	**136**	**0**	**-**
5618000	REL PLN & STAND SVCS	TNEX	Transmission O&M Expense	SG	6,610	92	1,835	485	879	2,947	372	0	-
5618000 Total					**6,610**	**92**	**1,835**	**485**	**879**	**2,947**	**372**	**0**	**-**
5620000	STATION EXP(TRANS)	TNEX	Transmission O&M Expense	SG	3,595	50	998	264	478	1,603	202	0	-
5620000 Total					**3,595**	**50**	**998**	**264**	**478**	**1,603**	**202**	**0**	**-**
5630000	OVERHEAD LINE EXP	TNEX	Transmission O&M Expense	SG	1,731	24	481	127	230	772	97	0	-
5630000 Total					**1,731**	**24**	**481**	**127**	**230**	**772**	**97**	**0**	**-**
5650000	TRNS ELEC BY OTHRS	NPCX	Net Power Cost Expense	SG	16,947	235	4,704	1,243	2,255	7,556	954	1	-
5650000 Total					**16,947**	**235**	**4,704**	**1,243**	**2,255**	**7,556**	**954**	**1**	**-**
5650010	EIM - TRANSM OF ELEC	NPCX	Net Power Cost Expense	SG	3,299	46	916	242	439	1,471	186	0	-
5650010 Total					**3,299**	**46**	**916**	**242**	**439**	**1,471**	**186**	**0**	**-**
5651000	S/T FIRM WHEELING	NPCX	Net Power Cost Expense	SG	13,552	188	3,761	994	1,803	6,042	763	1	-

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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5651000 Total					**13,552**	**188**	**3,761**	**994**	**1,803**	**6,042**	**763**	**1**	**-**
5652500	NON-FIRM WHEEL EXP	NPCX	Net Power Cost Expense	SE	26,339	329	7,065	1,767	3,777	11,814	1,585	1	-
5652500 Total					**26,339**	**329**	**7,065**	**1,767**	**3,777**	**11,814**	**1,585**	**1**	**-**
5654600	POST-MRG WHEEL EXP	NPCX	Net Power Cost Expense	SG	127,749	1,771	35,458	9,371	16,997	56,959	7,189	5	-
5654600 Total					**127,749**	**1,771**	**35,458**	**9,371**	**16,997**	**56,959**	**7,189**	**5**	**-**
5660000	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	4,251	59	1,180	312	566	1,895	239	0	-
5660000 Total					**4,251**	**59**	**1,180**	**312**	**566**	**1,895**	**239**	**0**	**-**
5660010	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	23	0	6	2	3	10	1	0	-
5660010 Total					**23**	**0**	**6**	**2**	**3**	**10**	**1**	**0**	**-**
5670000	RENTS-TRANSMISSION	TNEX	Transmission O&M Expense	SG	2,392	33	664	175	318	1,066	135	0	-
5670000 Total					**2,392**	**33**	**664**	**175**	**318**	**1,066**	**135**	**0**	**-**
5680000	MNT SUPERV & ENG	TNEX	Transmission O&M Expense	SG	1,746	24	485	128	232	778	98	0	-
5680000 Total					**1,746**	**24**	**485**	**128**	**232**	**778**	**98**	**0**	**-**
5690000	MAINT OF STRUCTURE	TNEX	Transmission O&M Expense	SG	(97)	(1)	(27)	(7)	(13)	(43)	(5)	(0)	-
5690000 Total					**(97)**	**(1)**	**(27)**	**(7)**	**(13)**	**(43)**	**(5)**	**(0)**	**-**
5691000	MAINT-COMP HW TRANS	TNEX	Transmission O&M Expense	SG	7	0	2	1	1	3	0	0	-
5691000 Total					**7**	**0**	**2**	**1**	**1**	**3**	**0**	**0**	**-**
5692000	MAINT-COMP SW TRANS	TNEX	Transmission O&M Expense	SG	1,463	20	406	107	195	652	82	0	-
5692000 Total					**1,463**	**20**	**406**	**107**	**195**	**652**	**82**	**0**	**-**
5693000	MAINT-COM EQP TRANS	TNEX	Transmission O&M Expense	SG	6,069	84	1,684	445	807	2,706	341	0	-
5693000 Total					**6,069**	**84**	**1,684**	**445**	**807**	**2,706**	**341**	**0**	**-**
5700000	MAINT STATION EQIP	TNEX	Transmission O&M Expense	SG	13,886	192	3,854	1,019	1,847	6,191	781	1	-
5700000 Total					**13,886**	**192**	**3,854**	**1,019**	**1,847**	**6,191**	**781**	**1**	**-**
5710000	MAINT OVHD LINES	TNEX	Transmission O&M Expense	SG	30,032	416	8,336	2,203	3,996	13,390	1,690	1	-
5710000 Total					**30,032**	**416**	**8,336**	**2,203**	**3,996**	**13,390**	**1,690**	**1**	**-**
5720000	MNT UNDERGRD LINES	TNEX	Transmission O&M Expense	SG	118	2	33	9	16	53	7	0	-
5720000 Total					**118**	**2**	**33**	**9**	**16**	**53**	**7**	**0**	**-**
5730000	MNT MSC TRANS PLNT	TNEX	Transmission O&M Expense	SG	316	4	88	23	42	141	18	0	-
5730000 Total					**316**	**4**	**88**	**23**	**42**	**141**	**18**	**0**	**-**
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	CA	251	251	-	-	-	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	307	-	-	-	-	-	307	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	OR	5,239	-	5,239	-	-	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	7,437	596	1,902	373	601	3,626	338	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	UT	2,095	-	-	-	-	2,095	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WA	329	-	-	329	-	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	182	-	-	-	182	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYU	108	-	-	-	108	-	-	-	-
5800000 Total					**15,947**	**847**	**7,141**	**702**	**891**	**5,720**	**645**	**-**	**-**
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	SNPD	17,222	1,380	4,405	864	1,392	8,396	784	-	-
5810000 Total					**17,222**	**1,380**	**4,405**	**864**	**1,392**	**8,396**	**784**	**-**	**-**
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	CA	121	121	-	-	-	-	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	IDU	288	-	-	-	-	-	288	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	OR	1,254	-	1,254	-	-	-	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	SNPD	0	0	0	0	0	0	0	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	UT	3,151	-	-	-	-	3,151	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WA	320	-	-	320	-	-	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYP	864	-	-	-	864	-	-	-	-
5820000 Total					**5,999**	**121**	**1,254**	**320**	**864**	**3,152**	**288**	**-**	**-**
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	CA	386	386	-	-	-	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	IDU	726	-	-	-	-	-	726	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	OR	1,452	-	1,452	-	-	-	-	-	-

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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	UT	8,124	-	-	-	-	8,124	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WA	416	-	-	416	-	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYP	1,522	-	-	-	1,522	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYU	129	-	-	-	129	-	-	-	-
5830000 Total					**12,755**	**386**	**1,452**	**416**	**1,651**	**8,124**	**726**	**-**	**-**
5850000	STRT LGHT-SGNL SYS	DNEX	Distribution O&M Expense	SNPD	305	24	78	15	25	149	14	-	-
5850000 Total					**305**	**24**	**78**	**15**	**25**	**149**	**14**	**-**	**-**
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	CA	182	182	-	-	-	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	IDU	231	-	-	-	-	-	231	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	OR	1,510	-	1,510	-	-	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	SNPD	10	1	3	1	1	5	0	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	UT	1,354	-	-	-	-	1,354	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WA	327	-	-	327	-	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYP	421	-	-	-	421	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYU	91	-	-	-	91	-	-	-	-
5860000 Total					**4,127**	**183**	**1,513**	**328**	**513**	**1,359**	**232**	**-**	**-**
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	CA	819	819	-	-	-	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	IDU	1,056	-	-	-	-	-	1,056	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	OR	7,108	-	7,108	-	-	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	UT	8,513	-	-	-	-	8,513	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WA	1,606	-	-	1,606	-	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYP	1,734	-	-	-	1,734	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYU	132	-	-	-	132	-	-	-	-
5870000 Total					**20,969**	**819**	**7,108**	**1,606**	**1,867**	**8,513**	**1,056**	**-**	**-**
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	CA	(18)	(18)	-	-	-	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	IDU	53	-	-	-	-	-	53	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	OR	(774)	-	(774)	-	-	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	SNPD	(1,684)	(135)	(431)	(85)	(136)	(821)	(77)	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	UT	721	-	-	-	-	721	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WA	(101)	-	-	(101)	-	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYP	316	-	-	-	316	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYU	(89)	-	-	-	(89)	-	-	-	-
5880000 Total					**(1,576)**	**(153)**	**(1,205)**	**(186)**	**91**	**(100)**	**(23)**	**-**	**-**
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	CA	38	38	-	-	-	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	IDU	81	-	-	-	-	-	81	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	OR	1,846	-	1,846	-	-	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	SNPD	572	46	146	29	46	279	26	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	UT	809	-	-	-	-	809	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WA	173	-	-	173	-	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYP	355	-	-	-	355	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYU	21	-	-	-	21	-	-	-	-
5890000 Total					**3,894**	**84**	**1,992**	**202**	**422**	**1,088**	**107**	**-**	**-**
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	CA	157	157	-	-	-	-	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	12	-	-	-	-	-	12	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	OR	1,456	-	1,456	-	-	-	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	4,178	335	1,069	210	338	2,037	190	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	UT	2,491	-	-	-	-	2,491	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WA	234	-	-	234	-	-	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	595	-	-	-	595	-	-	-	-
5900000 Total					**9,123**	**492**	**2,524**	**444**	**932**	**4,528**	**202**	**-**	**-**
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	CA	108	108	-	-	-	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	IDU	112	-	-	-	-	-	112	-	-

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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	OR	1,406	-	1,406	-	-	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	SNPD	131	11	34	7	11	64	6	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	UT	1,316	-	-	-	-	1,316	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WA	214	-	-	214	-	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYP	213	-	-	-	213	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYU	71	-	-	-	71	-	-	-	-
5910000 Total					**3,572**	**119**	**1,440**	**221**	**295**	**1,380**	**118**	**-**	**-**
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	CA	476	476	-	-	-	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	IDU	511	-	-	-	-	-	511	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	OR	3,911	-	3,911	-	-	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	SNPD	296	24	76	15	24	144	13	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	UT	2,917	-	-	-	-	2,917	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WA	1,093	-	-	1,093	-	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYP	948	-	-	-	948	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYU	(23)	-	-	-	(23)	-	-	-	-
5920000 Total					**10,129**	**500**	**3,987**	**1,108**	**949**	**3,061**	**524**	**-**	**-**
5922000	MAINT COMP HW-DISTRI	DNEX	Distribution O&M Expense	CA	1	1	-	-	-	-	-	-	-
5922000	MAINT COMP HW-DISTRI	DNEX	Distribution O&M Expense	IDU	0	-	-	-	-	-	0	-	-
5922000	MAINT COMP HW-DISTRI	DNEX	Distribution O&M Expense	OR	1	-	1	-	-	-	-	-	-
5922000	MAINT COMP HW-DISTRI	DNEX	Distribution O&M Expense	SNPD	22	2	6	1	2	11	1	-	-
5922000	MAINT COMP HW-DISTRI	DNEX	Distribution O&M Expense	UT	50	-	-	-	-	50	-	-	-
5922000	MAINT COMP HW-DISTRI	DNEX	Distribution O&M Expense	WA	0	-	-	0	-	-	-	-	-
5922000 Total					**75**	**2**	**7**	**1**	**2**	**61**	**1**	**-**	**-**
5923000	MAINT COMP SW-DISTRI	DNEX	Distribution O&M Expense	CA	(2)	(2)	-	-	-	-	-	-	-
5923000	MAINT COMP SW-DISTRI	DNEX	Distribution O&M Expense	OR	0	-	0	-	-	-	-	-	-
5923000	MAINT COMP SW-DISTRI	DNEX	Distribution O&M Expense	SNPD	2,867	230	733	144	232	1,398	130	-	-
5923000 Total					**2,866**	**228**	**734**	**144**	**232**	**1,398**	**130**	**-**	**-**
5924000	MAINT COMM EQP-DISTR	DNEX	Distribution O&M Expense	CA	288	288	-	-	-	-	-	-	-
5924000	MAINT COMM EQP-DISTR	DNEX	Distribution O&M Expense	IDU	554	-	-	-	-	-	554	-	-
5924000	MAINT COMM EQP-DISTR	DNEX	Distribution O&M Expense	OR	1,151	-	1,151	-	-	-	-	-	-
5924000	MAINT COMM EQP-DISTR	DNEX	Distribution O&M Expense	SNPD	129	10	33	6	10	63	6	-	-
5924000	MAINT COMM EQP-DISTR	DNEX	Distribution O&M Expense	UT	644	-	-	-	-	644	-	-	-
5924000	MAINT COMM EQP-DISTR	DNEX	Distribution O&M Expense	WA	286	-	-	286	-	-	-	-	-
5924000	MAINT COMM EQP-DISTR	DNEX	Distribution O&M Expense	WYP	215	-	-	-	215	-	-	-	-
5924000 Total					**3,267**	**298**	**1,184**	**293**	**226**	**706**	**560**	**-**	**-**
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	CA	13,158	13,158	-	-	-	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	IDU	5,510	-	-	-	-	-	5,510	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	OR	96,454	-	96,454	-	-	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	SNPD	3,726	299	953	187	301	1,816	170	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	UT	41,487	-	-	-	-	41,487	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WA	11,577	-	-	11,577	-	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYP	9,569	-	-	-	9,569	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYU	1,377	-	-	-	1,377	-	-	-	-
5930000 Total					**182,859**	**13,457**	**97,407**	**11,764**	**11,248**	**43,304**	**5,680**	**-**	**-**
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	CA	(316)	(316)	-	-	-	-	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	IDU	(202)	-	-	-	-	-	(202)	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	OR	(2,058)	-	(2,058)	-	-	-	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	UT	2,010	-	-	-	-	2,010	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WA	(543)	-	-	(543)	-	-	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYP	901	-	-	-	901	-	-	-	-
5931000 Total					**(209)**	**(316)**	**(2,058)**	**(543)**	**901**	**2,010**	**(202)**	**-**	**-**
5932000	MAINT O/H LINES-WMP	DNEX	Distribution O&M Expense	OTHER	2,249	-	-	-	-	-	-	-	2,249

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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5932000	MAINT O/H LINES-WMP	DNEX	Distribution O&M Expense	OTHER	7,247	-	-	-	-	-	-	-	7,247
5932000	MAINT O/H LINES-WMP	DNEX	Distribution O&M Expense	OTHER	789	-	-	-	-	-	-	-	789
5932000	MAINT O/H LINES-WMP	DNEX	Distribution O&M Expense	OTHER	(279)	-	-	-	-	-	-	-	(279)
5932000	MAINT O/H LINES-WMP	DNEX	Distribution O&M Expense	OTHER	411	-	-	-	-	-	-	-	411
5932000	MAINT O/H LINES-WMP	DNEX	Distribution O&M Expense	OTHER	435	-	-	-	-	-	-	-	435
5932000 Total					**10,852**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**10,852**
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	CA	869	869	-	-	-	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	IDU	1,404	-	-	-	-	-	1,404	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	OR	10,894	-	10,894	-	-	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	SNPD	8	1	2	0	1	4	0	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	UT	23,753	-	-	-	-	23,753	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WA	2,589	-	-	2,589	-	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYP	2,277	-	-	-	2,277	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYU	349	-	-	-	349	-	-	-	-
5940000 Total					**42,143**	**870**	**10,896**	**2,589**	**2,627**	**23,756**	**1,404**	**-**	**-**
5950000	MAINT LINE TRNSFRM	DNEX	Distribution O&M Expense	SNPD	1,046	84	268	52	85	510	48	-	-
5950000 Total					**1,046**	**84**	**268**	**52**	**85**	**510**	**48**	**-**	**-**
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	CA	58	58	-	-	-	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	IDU	57	-	-	-	-	-	57	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	OR	824	-	824	-	-	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	UT	542	-	-	-	-	542	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WA	57	-	-	57	-	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYP	383	-	-	-	383	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYU	82	-	-	-	82	-	-	-	-
5960000 Total					**2,002**	**58**	**824**	**57**	**465**	**542**	**57**	**-**	**-**
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	CA	23	23	-	-	-	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	IDU	19	-	-	-	-	-	19	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	OR	216	-	216	-	-	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	SNPD	(149)	(12)	(38)	(8)	(12)	(73)	(7)	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	UT	211	-	-	-	-	211	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WA	207	-	-	207	-	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYP	26	-	-	-	26	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYU	33	-	-	-	33	-	-	-	-
5970000 Total					**586**	**11**	**178**	**199**	**47**	**138**	**13**	**-**	**-**
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	CA	165	165	-	-	-	-	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	IDU	173	-	-	-	-	-	173	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	OR	1,039	-	1,039	-	-	-	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	SNPD	1,719	138	440	86	139	838	78	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	UT	1,238	-	-	-	-	1,238	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WA	566	-	-	566	-	-	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYP	225	-	-	-	225	-	-	-	-
5980000 Total					**5,125**	**302**	**1,479**	**652**	**364**	**2,076**	**251**	**-**	**-**
5989500	MNT DIST PLNT-ENV AM	DNEX	Distribution O&M Expense	SNPD	2,663	213	681	134	215	1,298	121	-	-
5989500 Total					**2,663**	**213**	**681**	**134**	**215**	**1,298**	**121**	**-**	**-**
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	CN	21,093	463	6,357	1,449	1,459	10,461	904	-	-
9010000 Total					**21,093**	**463**	**6,357**	**1,449**	**1,459**	**10,461**	**904**	**-**	**-**
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CA	431	431	-	-	-	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CN	1,262	28	380	87	87	626	54	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	IDU	184	-	-	-	-	-	184	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	OR	2,037	-	2,037	-	-	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	UT	2,520	-	-	-	-	2,520	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WA	1,035	-	-	1,035	-	-	-	-	-

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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYP	1,416	-	-	-	1,416	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYU	299	-	-	-	299	-	-	-	-
9020000 Total					**9,186**	**459**	**2,418**	**1,122**	**1,803**	**3,146**	**238**	**-**	**-**
9030000	CUST RCRD/COLL EXP	CAEX	Customer Accounting Expense	CN	1,234	27	372	85	85	612	53	-	-
9030000 Total					**1,234**	**27**	**372**	**85**	**85**	**612**	**53**	**-**	**-**
9031000	CUST RCRD/CUST SYS	CAEX	Customer Accounting Expense	CN	2,226	49	671	153	154	1,104	95	-	-
9031000 Total					**2,226**	**49**	**671**	**153**	**154**	**1,104**	**95**	**-**	**-**
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	CN	11,038	242	3,327	758	764	5,474	473	-	-
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	OR	10	-	10	-	-	-	-	-	-
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	WYP	0	-	-	-	0	-	-	-	-
9032000 Total					**11,049**	**242**	**3,337**	**758**	**764**	**5,474**	**473**	**-**	**-**
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CA	39	39	-	-	-	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CN	2,114	46	637	145	146	1,048	91	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	IDU	127	-	-	-	-	-	127	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	OR	662	-	662	-	-	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	UT	3,659	-	-	-	-	3,659	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WA	805	-	-	805	-	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYP	390	-	-	-	390	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYU	59	-	-	-	59	-	-	-	-
9033000 Total					**7,853**	**85**	**1,299**	**950**	**595**	**4,707**	**218**	**-**	**-**
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	CA	45	45	-	-	-	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	IDU	22	-	-	-	-	-	22	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	OR	155	-	155	-	-	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	UT	154	-	-	-	-	154	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WA	35	-	-	35	-	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYP	33	-	-	-	33	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYU	11	-	-	-	11	-	-	-	-
9035000 Total					**455**	**45**	**155**	**35**	**44**	**154**	**22**	**-**	**-**
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	CN	13,241	291	3,991	910	916	6,566	567	-	-
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	OR	145	-	145	-	-	-	-	-	-
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	WA	3,033	-	-	3,033	-	-	-	-	-
9036000 Total					**16,418**	**291**	**4,135**	**3,943**	**916**	**6,566**	**567**	**-**	**-**
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CA	1,388	1,388	-	-	-	-	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CN	(8)	(0)	(3)	(1)	(1)	(4)	(0)	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	IDU	510	-	-	-	-	-	510	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	OR	11,370	-	11,370	-	-	-	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	UT	7,452	-	-	-	-	7,452	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WA	3,877	-	-	3,877	-	-	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WYP	1,834	-	-	-	1,834	-	-	-	-
9040000 Total					**26,423**	**1,388**	**11,368**	**3,876**	**1,833**	**7,448**	**510**	**-**	**-**
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	CA	(0)	(0)	-	-	-	-	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	IDU	1	-	-	-	-	-	1	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	OR	(44)	-	(44)	-	-	-	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	UT	(29)	-	-	-	-	(29)	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WA	(39)	-	-	(39)	-	-	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WYP	(8)	-	-	-	(8)	-	-	-	-
9042000 Total					**(119)**	**(0)**	**(44)**	**(39)**	**(8)**	**(29)**	**1**	**-**	**-**
9050000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	OR	0	-	0	-	-	-	-	-	-
9050000 Total					**0**	**-**	**0**	**-**	**-**	**-**	**-**	**-**	**-**
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	CN	890	20	268	61	62	441	38	-	-
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	OR	0	-	0	-	-	-	-	-	-
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	UT	(0)	-	-	-	-	(0)	-	-	-

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Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9080000 Total					**890**	**20**	**269**	**61**	**62**	**441**	**38**	**-**	**-**
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	CN	699	15	211	48	48	347	30	-	-
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	OTHER	4,569	-	-	-	-	-	-	-	4,569
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	UT	(1,851)	-	-	-	-	(1,851)	-	-	-
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	WA	2,326	-	-	2,326	-	-	-	-	-
9081000 Total					**5,743**	**15**	**211**	**2,374**	**48**	**(1,505)**	**30**	**-**	**4,569**
9084000	DSM DIRECT	CSEX	Customer Service Expense	CA	128	128	-	-	-	-	-	-	-
9084000	DSM DIRECT	CSEX	Customer Service Expense	CN	1,484	33	447	102	103	736	64	-	-
9084000	DSM DIRECT	CSEX	Customer Service Expense	OTHER	96	-	-	-	-	-	-	-	96
9084000	DSM DIRECT	CSEX	Customer Service Expense	WA	0	-	-	0	-	-	-	-	-
9084000 Total					**1,708**	**160**	**447**	**102**	**103**	**736**	**64**	**-**	**96**
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	OTHER	195,427	-	-	-	-	-	-	-	195,427
9085100 Total					**195,427**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**195,427**
9086000	CUST SERV	CSEX	Customer Service Expense	CA	203	203	-	-	-	-	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	CN	952	21	287	65	66	472	41	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	IDU	58	-	-	-	-	-	58	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	OR	2,214	-	2,214	-	-	-	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	UT	3,148	-	-	-	-	3,148	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	WA	420	-	-	420	-	-	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	WYP	1,035	-	-	-	1,035	-	-	-	-
9086000 Total					**8,031**	**224**	**2,501**	**486**	**1,101**	**3,620**	**99**	**-**	**-**
9089400	ELEC VEHICLE PROGRAM	CSEX	Customer Service Expense	OTHER	7,506	-	-	-	-	-	-	-	7,506
9089400	ELEC VEHICLE PROGRAM	CSEX	Customer Service Expense	WA	686	-	-	686	-	-	-	-	-
9089400 Total					**8,192**	**-**	**-**	**686**	**-**	**-**	**-**	**-**	**7,506**
9089500	BLUE SKY EXPENSE	CSEX	Customer Service Expense	OTHER	7,342	-	-	-	-	-	-	-	7,342
9089500 Total					**7,342**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**7,342**
9089600	SOLAR FEED-IN EXP	CSEX	Customer Service Expense	OTHER	2,991	-	-	-	-	-	-	-	2,991
9089600 Total					**2,991**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**2,991**
9089700	SUBSCRIBER SOLAR	CSEX	Customer Service Expense	UT	200	-	-	-	-	200	-	-	-
9089700 Total					**200**	**-**	**-**	**-**	**-**	**200**	**-**	**-**	**-**
9089800	COMMUNITY SOLAR	CSEX	Customer Service Expense	OTHER	1,669	-	-	-	-	-	-	-	1,669
9089800 Total					**1,669**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1,669**
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CA	76	76	-	-	-	-	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CN	3,420	75	1,031	235	237	1,696	147	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	IDU	86	-	-	-	-	-	86	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	OR	456	-	456	-	-	-	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	UT	729	-	-	-	-	729	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WA	236	-	-	236	-	-	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WYP	210	-	-	-	210	-	-	-	-
9090000 Total					**5,213**	**151**	**1,487**	**471**	**446**	**2,425**	**232**	**-**	**-**
9100000	MISC CUST SERV/INF	CSEX	Customer Service Expense	CN	154	3	46	11	11	76	7	-	-
9100000 Total					**154**	**3**	**46**	**11**	**11**	**76**	**7**	**-**	**-**
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	CA	7	7	-	-	-	-	-	-	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	OR	(25)	-	(25)	-	-	-	-	-	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	SO	88,243	2,676	24,628	6,194	10,721	39,278	4,745	2	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	UT	(0)	-	-	-	-	(0)	-	-	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	WYP	43	-	-	-	43	-	-	-	-
9200000 Total					**88,268**	**2,682**	**24,603**	**6,194**	**10,765**	**39,278**	**4,745**	**2**	**-**
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CA	2	2	-	-	-	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CN	117	3	35	8	8	58	5	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	IDU	3	-	-	-	-	-	3	-	-

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Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	OR	500	-	500	-	-	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	SO	13,956	423	3,895	980	1,696	6,212	750	0	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	UT	121	-	-	-	-	121	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WA	10	-	-	10	-	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYP	24	-	-	-	24	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYU	2	-	-	-	2	-	-	-	-
9210000 Total					**14,734**	**427**	**4,430**	**997**	**1,730**	**6,391**	**758**	**0**	**-**
9220000	A&G EXP TRANSF-CR	AGEX	Administrative & General Expense	SO	(45,396)	(1,376)	(12,670)	(3,186)	(5,516)	(20,206)	(2,441)	(1)	-
9220000 Total					**(45,396)**	**(1,376)**	**(12,670)**	**(3,186)**	**(5,516)**	**(20,206)**	**(2,441)**	**(1)**	**-**
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	CA	605	605	-	-	-	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	IDU	3	-	-	-	-	-	3	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	OR	(636)	-	(636)	-	-	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	SO	20,959	635	5,850	1,471	2,547	9,329	1,127	1	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	UT	521	-	-	-	-	521	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WA	1,027	-	-	1,027	-	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYP	64	-	-	-	64	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYU	110	-	-	-	110	-	-	-	-
9230000 Total					**22,655**	**1,241**	**5,214**	**2,498**	**2,721**	**9,850**	**1,130**	**1**	**-**
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	CA	(1)	(1)	-	-	-	-	-	-	-
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	SO	27,440	832	7,658	1,926	3,334	12,214	1,475	1	-
9239990 Total					**27,439**	**831**	**7,658**	**1,926**	**3,334**	**12,214**	**1,475**	**1**	**-**
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	CA	1,800	1,800	-	-	-	-	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	IDU	35	-	-	-	-	-	35	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	OR	14,545	-	14,545	-	-	-	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	UT	766	-	-	-	-	766	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	WA	1,378	-	-	1,378	-	-	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	WYP	250	-	-	-	250	-	-	-	-
9241000 Total					**18,775**	**1,800**	**14,545**	**1,378**	**250**	**766**	**35**	**-**	**-**
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	CA	75	75	-	-	-	-	-	-	-
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	IDU	16	-	-	-	-	-	16	-	-
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	OR	(166)	-	(166)	-	-	-	-	-	-
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	UT	130	-	-	-	-	130	-	-	-
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	WA	(93)	-	-	(93)	-	-	-	-	-
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	WYP	41	-	-	-	41	-	-	-	-
9242000 Total					**4**	**75**	**(166)**	**(93)**	**41**	**130**	**16**	**-**	**-**
9243000	PROP INS - PREMIUMS	AGEX	Administrative & General Expense	SO	6,154	187	1,717	432	748	2,739	331	0	-
9243000 Total					**6,154**	**187**	**1,717**	**432**	**748**	**2,739**	**331**	**0**	**-**
9250000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	261,348	7,924	72,939	18,343	31,753	116,329	14,052	7	-
9250000 Total					**261,348**	**7,924**	**72,939**	**18,343**	**31,753**	**116,329**	**14,052**	**7**	**-**
9251000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	OR	5,088	-	5,088	-	-	-	-	-	-
9251000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	(5,088)	(154)	(1,420)	(357)	(618)	(2,265)	(274)	(0)	-
9251000 Total					**-**	**(154)**	**3,668**	**(357)**	**(618)**	**(2,265)**	**(274)**	**(0)**	**-**
9261200	PEN EXP-OTH NBC	AGEX	Administrative & General Expense	SO	(6,679)	(202)	(1,864)	(469)	(811)	(2,973)	(359)	(0)	-
9261200 Total					**(6,679)**	**(202)**	**(1,864)**	**(469)**	**(811)**	**(2,973)**	**(359)**	**(0)**	**-**
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	CA	80	80	-	-	-	-	-	-	-
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	OR	536	-	536	-	-	-	-	-	-
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	UT	(33)	-	-	-	-	(33)	-	-	-
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	WA	236	-	-	236	-	-	-	-	-
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	WYP	319	-	-	-	319	-	-	-	-
9261500 Total					**1,138**	**80**	**536**	**236**	**319**	**(33)**	**-**	**-**	**-**
9262200	POSTRET EXP-OTH NBC	AGEX	Administrative & General Expense	SO	(4,244)	(129)	(1,184)	(298)	(516)	(1,889)	(228)	(0)	-

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Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9262200 Total					**(4,244)**	**(129)**	**(1,184)**	**(298)**	**(516)**	**(1,889)**	**(228)**	**(0)**	**-**
9262500	POSTRET EXP-ST SITUS	AGEX	Administrative & General Expense	IDU	87	-	-	-	-	-	87	-	-
9262500 Total					**87**	**-**	**-**	**-**	**-**	**-**	**87**	**-**	**-**
9263200	SERP EXP-OTH NBC	AGEX	Administrative & General Expense	SO	2,750	83	768	193	334	1,224	148	0	-
9263200 Total					**2,750**	**83**	**768**	**193**	**334**	**1,224**	**148**	**0**	**-**
9269100	GROSS-UP - PENSION	AGEX	Administrative & General Expense	SO	4,920	149	1,373	345	598	2,190	265	0	-
9269100 Total					**4,920**	**149**	**1,373**	**345**	**598**	**2,190**	**265**	**0**	**-**
9269200	GROSS-UP - POST-RETR	AGEX	Administrative & General Expense	SO	2,018	61	563	142	245	898	109	0	-
9269200 Total					**2,018**	**61**	**563**	**142**	**245**	**898**	**109**	**0**	**-**
9269400	GROSS-UP - MD/DN/V/L	AGEX	Administrative & General Expense	SO	74,370	2,255	20,756	5,220	9,036	33,103	3,999	2	-
9269400 Total					**74,370**	**2,255**	**20,756**	**5,220**	**9,036**	**33,103**	**3,999**	**2**	**-**
9269500	GROSS-UP - 401(K) EX	AGEX	Administrative & General Expense	SO	54,963	1,666	15,340	3,858	6,678	24,465	2,955	2	-
9269500 Total					**54,963**	**1,666**	**15,340**	**3,858**	**6,678**	**24,465**	**2,955**	**2**	**-**
9269600	GROSS-UP - POST-EMPL	AGEX	Administrative & General Expense	SO	4,859	147	1,356	341	590	2,163	261	0	-
9269600 Total					**4,859**	**147**	**1,356**	**341**	**590**	**2,163**	**261**	**0**	**-**
9269700	GROSS-UP - OTH BEN E	AGEX	Administrative & General Expense	SO	8,513	258	2,376	598	1,034	3,789	458	0	-
9269700 Total					**8,513**	**258**	**2,376**	**598**	**1,034**	**3,789**	**458**	**0**	**-**
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	CA	615	615	-	-	-	-	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	IDU	150	-	-	-	-	-	150	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	OR	2,109	-	2,109	-	-	-	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	SO	2,687	81	750	189	326	1,196	144	0	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	UT	1,776	-	-	-	-	1,776	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WA	165	-	-	165	-	-	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WYP	1,518	-	-	-	1,518	-	-	-	-
9280000 Total					**9,020**	**697**	**2,859**	**354**	**1,844**	**2,972**	**295**	**0**	**-**
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	CA	179	179	-	-	-	-	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	IDU	661	-	-	-	-	-	661	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	OR	9,690	-	9,690	-	-	-	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	SO	0	0	0	0	0	0	0	0	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	UT	6,577	-	-	-	-	6,577	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WA	1,699	-	-	1,699	-	-	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WYP	1,944	-	-	-	1,944	-	-	-	-
9282000 Total					**20,750**	**179**	**9,690**	**1,699**	**1,944**	**6,577**	**661**	**0**	**-**
9283000	FERC FILING FEE	AGEX	Administrative & General Expense	SG	4,665	65	1,295	342	621	2,080	263	0	-
9283000 Total					**4,665**	**65**	**1,295**	**342**	**621**	**2,080**	**263**	**0**	**-**
9290000	DUPLICATE CHRGS-CR	AGEX	Administrative & General Expense	SO	(14,686)	(445)	(4,099)	(1,031)	(1,784)	(6,537)	(790)	(0)	-
9290000 Total					**(14,686)**	**(445)**	**(4,099)**	**(1,031)**	**(1,784)**	**(6,537)**	**(790)**	**(0)**	**-**
9299100	DUP CHG CR - PENSION	AGEX	Administrative & General Expense	SO	(4,920)	(149)	(1,373)	(345)	(598)	(2,190)	(265)	(0)	-
9299100 Total					**(4,920)**	**(149)**	**(1,373)**	**(345)**	**(598)**	**(2,190)**	**(265)**	**(0)**	**-**
9299200	DUP CHG CR - POST-RT	AGEX	Administrative & General Expense	SO	(2,018)	(61)	(563)	(142)	(245)	(898)	(109)	(0)	-
9299200 Total					**(2,018)**	**(61)**	**(563)**	**(142)**	**(245)**	**(898)**	**(109)**	**(0)**	**-**
9299400	DUP CHG CR - M/D/V/L	AGEX	Administrative & General Expense	SO	(74,370)	(2,255)	(20,756)	(5,220)	(9,036)	(33,103)	(3,999)	(2)	-
9299400 Total					**(74,370)**	**(2,255)**	**(20,756)**	**(5,220)**	**(9,036)**	**(33,103)**	**(3,999)**	**(2)**	**-**
9299500	DUP CHRG CR - 401(K)	AGEX	Administrative & General Expense	SO	(54,963)	(1,666)	(15,340)	(3,858)	(6,678)	(24,465)	(2,955)	(2)	-
9299500 Total					**(54,963)**	**(1,666)**	**(15,340)**	**(3,858)**	**(6,678)**	**(24,465)**	**(2,955)**	**(2)**	**-**
9299600	DUP CHG CR - POST-EM	AGEX	Administrative & General Expense	SO	(4,859)	(147)	(1,356)	(341)	(590)	(2,163)	(261)	(0)	-
9299600 Total					**(4,859)**	**(147)**	**(1,356)**	**(341)**	**(590)**	**(2,163)**	**(261)**	**(0)**	**-**
9299700	DUP CHG CR - OTH BEN	AGEX	Administrative & General Expense	SO	(8,513)	(258)	(2,376)	(598)	(1,034)	(3,789)	(458)	(0)	-
9299700 Total					**(8,513)**	**(258)**	**(2,376)**	**(598)**	**(1,034)**	**(3,789)**	**(458)**	**(0)**	**-**
9301000	GEN ADVERTISNG EXP	AGEX	Administrative & General Expense	OR	3	-	3	-	-	-	-	-	-
9301000	GEN ADVERTISNG EXP	AGEX	Administrative & General Expense	SO	361	11	101	25	44	161	19	0	-

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9301000 Total					**364**	**11**	**104**	**25**	**44**	**161**	**19**	**0**	**-**
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	CA	(1)	(1)	-	-	-	-	-	-	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	OR	0	-	0	-	-	-	-	-	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	SO	2,094	63	584	147	254	932	113	0	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	WA	(3)	-	-	(3)	-	-	-	-	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	WYP	73	-	-	-	73	-	-	-	-
9302000 Total					**2,164**	**63**	**585**	**144**	**327**	**932**	**113**	**0**	**-**
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	CA	6	6	-	-	-	-	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	OR	90	-	90	-	-	-	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	SO	639	19	178	45	78	285	34	0	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	UT	2	-	-	-	-	2	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WA	5	-	-	5	-	-	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WYP	20	-	-	-	20	-	-	-	-
9310000 Total					**762**	**25**	**268**	**50**	**98**	**286**	**34**	**0**	**-**
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CA	204	204	-	-	-	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CN	83	2	25	6	6	41	4	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	IDU	49	-	-	-	-	-	49	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	OR	309	-	309	-	-	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	SO	19,850	602	5,540	1,393	2,412	8,836	1,067	1	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	UT	124	-	-	-	-	124	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WA	219	-	-	219	-	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYP	37	-	-	-	37	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYU	(5)	-	-	-	(5)	-	-	-	-
9350000 Total					**20,871**	**807**	**5,874**	**1,618**	**2,450**	**9,001**	**1,120**	**1**	**-**
9351000	MAINT COMP HW-GENERI	AGEX	Administrative & General Expense	OR	(2)	-	(2)	-	-	-	-	-	-
9351000	MAINT COMP HW-GENERI	AGEX	Administrative & General Expense	SO	707	21	197	50	86	315	38	0	-
9351000 Total					**705**	**21**	**195**	**50**	**86**	**315**	**38**	**0**	**-**
9352000	MAINT COMP SW-GENERI	AGEX	Administrative & General Expense	SO	16,914	513	4,720	1,187	2,055	7,529	909	0	-
9352000 Total					**16,914**	**513**	**4,720**	**1,187**	**2,055**	**7,529**	**909**	**0**	**-**
9353000	MNT COMM EQP-GENERA	AGEX	Administrative & General Expense	SO	27	1	7	2	3	12	1	0	-
9353000 Total					**27**	**1**	**7**	**2**	**3**	**12**	**1**	**0**	**-**
9359500	MAINT GEN PLT-ENV AM	AGEX	Administrative & General Expense	SO	273	8	76	19	33	121	15	0	-
9359500 Total					**273**	**8**	**76**	**19**	**33**	**121**	**15**	**0**	**-**
Grand Total					**4,732,744**	**82,939**	**1,230,239**	**302,578**	**535,128**	**1,834,148**	**231,142**	**155**	**516,415**

B3. DEPRECIATON EXPENSE

PACIFICORP

Depreciation Expense (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELEC	3102000	LAND RIGHTS	SG	393.27	5	109	29	52	175	22	0	-
4030000	DEPN EXPENSE-ELEC	3110000	STRUCTURES AND IMPROVEMENTS	SG	45,246.54	627	12,558	3,319	6,020	20,174	2,546	2	-
4030000	DEPN EXPENSE-ELEC	3120000	BOILER PLANT EQUIPMENT	SG	237,454.38	3,292	65,907	17,419	31,592	105,873	13,362	10	-
4030000	DEPN EXPENSE-ELEC	3140000	TURBOGENERATOR UNITS	SG	50,419.87	699	13,994	3,699	6,708	22,481	2,837	2	-
4030000	DEPN EXPENSE-ELEC	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	18,052.31	250	5,011	1,324	2,402	8,049	1,016	1	-
4030000	DEPN EXPENSE-ELEC	3151000	COMPUTER HARDWARE - STEAM	SG	27.72	0	8	2	4	12	2	0	-
4030000	DEPN EXPENSE-ELEC	3152000	COMPUTER SOFTWARE (MISC) - STEAM	SG	4.41	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELEC	3153000	COMMUNICATION EQUIPMENT - STEAM	SG	388.01	5	108	28	52	173	22	0	-
4030000	DEPN EXPENSE-ELEC	3153005	COMM EQUIP - MOBILE RADIOS - STEAM	SG	8.91	0	2	1	1	4	1	0	-
4030000	DEPN EXPENSE-ELEC	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	1.85	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	1,766.56	24	490	130	235	788	99	0	-
4030000	DEPN EXPENSE-ELEC	3302000	LAND RIGHTS	SG-P	11.64	0	3	1	2	5	1	0	-
4030000	DEPN EXPENSE-ELEC	3302000	LAND RIGHTS	SG-U	40.10	1	11	3	5	18	2	0	-
4030000	DEPN EXPENSE-ELEC	3303000	WATER RIGHTS	SG-P	0.42	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELEC	3303000	WATER RIGHTS	SG-U	1.66	0	0	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3304000	FLOOD RIGHTS	SG-P	(68.08)	(1)	(19)	(5)	(9)	(30)	(4)	(0)	-
4030000	DEPN EXPENSE-ELEC	3304000	FLOOD RIGHTS	SG-U	2.66	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	2.44	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3310000	STRUCTURES AND IMPROVE	SG-P	(2.26)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
4030000	DEPN EXPENSE-ELEC	3310000	STRUCTURES AND IMPROVE	SG-U	317.85	4	88	23	42	142	18	0	-
4030000	DEPN EXPENSE-ELEC	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	1,435.23	20	398	105	191	640	81	0	-
4030000	DEPN EXPENSE-ELEC	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	451.50	6	125	33	60	201	25	0	-
4030000	DEPN EXPENSE-ELEC	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	3,908.17	54	1,085	287	520	1,743	220	0	-
4030000	DEPN EXPENSE-ELEC	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	31.86	0	9	2	4	14	2	0	-
4030000	DEPN EXPENSE-ELEC	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	602.65	8	167	44	80	269	34	0	-
4030000	DEPN EXPENSE-ELEC	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	17.17	0	5	1	2	8	1	0	-
4030000	DEPN EXPENSE-ELEC	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	163.61	2	45	12	22	73	9	0	-
4030000	DEPN EXPENSE-ELEC	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	1,168.88	16	324	86	156	521	66	0	-
4030000	DEPN EXPENSE-ELEC	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	10,465.49	145	2,905	768	1,392	4,666	589	0	-
4030000	DEPN EXPENSE-ELEC	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	4,182.96	58	1,161	307	557	1,865	235	0	-
4030000	DEPN EXPENSE-ELEC	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	450.08	6	125	33	60	201	25	0	-
4030000	DEPN EXPENSE-ELEC	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	16.88	0	5	1	2	8	1	0	-
4030000	DEPN EXPENSE-ELEC	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	3.57	0	1	0	0	2	0	0	-
4030000	DEPN EXPENSE-ELEC	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	0.55	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELEC	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	3,790.43	53	1,052	278	504	1,690	213	0	-
4030000	DEPN EXPENSE-ELEC	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	1,966.95	27	546	144	262	877	111	0	-
4030000	DEPN EXPENSE-ELEC	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	1,503.41	21	417	110	200	670	85	0	-
4030000	DEPN EXPENSE-ELEC	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	594.16	8	165	44	79	265	33	0	-
4030000	DEPN EXPENSE-ELEC	3341000	COMPUTER HARDWARE - HYDRO	SG	11.43	0	3	1	2	5	1	0	-
4030000	DEPN EXPENSE-ELEC	3342000	COMPUTER SOFTWARE (MISC) - HYDRO	SG	0.19	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELEC	3343000	COMMUNICATION EQUIPMENT - HYDRO	SG	273.58	4	76	20	36	122	15	0	-
4030000	DEPN EXPENSE-ELEC	3343005	COMM EQUIP - MOBILE RADIOS - HYDRO	SG	2.87	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	18.52	0	5	1	2	8	1	0	-
4030000	DEPN EXPENSE-ELEC	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	5.18	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELEC	3350000	MISC POWER PLANT EQUIP	SG-U	7.62	0	2	1	1	3	0	0	-
4030000	DEPN EXPENSE-ELEC	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	76.34	1	21	6	10	34	4	0	-
4030000	DEPN EXPENSE-ELEC	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	872.46	12	242	64	116	389	49	0	-
4030000	DEPN EXPENSE-ELEC	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	216.98	3	60	16	29	97	12	0	-
4030000	DEPN EXPENSE-ELEC	3380002	STRUCTURES AND IMPROVEMENTS - SOLAR	OR	0.07	-	0	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3380002	STRUCTURES AND IMPROVEMENTS - SOLAR	UT	1.34	-	-	-	-	1	-	-	-
4030000	DEPN EXPENSE-ELEC	3380004	SOLAR PANELS	UT	6.22	-	-	-	-	6	-	-	-

PACIFICORP

Depreciation Expense (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELEC	3380005	COLLECTOR SYSTEM - SOLAR	UT	2.84	-	-	-	-	3	-	-	-
4030000	DEPN EXPENSE-ELEC	3380007	INVERTERS - SOLAR	UT	0.69	-	-	-	-	1	-	-	-
4030000	DEPN EXPENSE-ELEC	3380008	ACCESSORY ELECTRIC EQUIPMENT - SOLAR	UT	0.60	-	-	-	-	1	-	-	-
4030000	DEPN EXPENSE-ELEC	3380011	COMMUNICATION EQUIPMENT - SOLAR	OR	1.64	-	2	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3382000	LAND RIGHTS - WIND PRODUCTION	SG	167.43	2	46	12	22	75	9	0	-
4030000	DEPN EXPENSE-ELEC	3382100	STRUCTURES AND IMPROVEMENTS - WIND	SG	4,843.61	67	1,344	355	644	2,160	273	0	-
4030000	DEPN EXPENSE-ELEC	3382300	WIND TURBINES	SG	41,055.36	569	11,395	3,012	5,462	18,305	2,310	2	-
4030000	DEPN EXPENSE-ELEC	3382301	WIND TURBINES - GENERATORS	SG	4,378.57	61	1,215	321	583	1,952	246	0	-
4030000	DEPN EXPENSE-ELEC	3382400	WIND TOWERS AND FIXTURES	SG	14,133.71	196	3,923	1,037	1,880	6,302	795	1	-
4030000	DEPN EXPENSE-ELEC	3382600	COLLECTOR SYSTEM - WIND	SG	3,718.04	52	1,032	273	495	1,658	209	0	-
4030000	DEPN EXPENSE-ELEC	3382700	GSU AND ASSOC EQUIP - WIND	SG	552.54	8	153	41	74	246	31	0	-
4030000	DEPN EXPENSE-ELEC	3382800	INVERTERS - WIND	SG	47.36	1	13	3	6	21	3	0	-
4030000	DEPN EXPENSE-ELEC	3382900	ACCESSORY ELECTRIC EQUIPMENT - WIND	SG	137.20	2	38	10	18	61	8	0	-
4030000	DEPN EXPENSE-ELEC	3383000	COMPUTER HARDWARE - WIND	SG	19.10	0	5	1	3	9	1	0	-
4030000	DEPN EXPENSE-ELEC	3383100	COMPUTER SOFTWARE (MISC) - WIND	SG	2.65	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3383200	COMMUNICATION EQUIPMENT - WIND	SG	51.46	1	14	4	7	23	3	0	-
4030000	DEPN EXPENSE-ELEC	3383205	COMM EQUIP - MOBILE RADIOS - WIND	SG	3.01	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3383300	MISC POWER PLANT EQUIP - WIND	SG	236.60	3	66	17	31	105	13	0	-
4030000	DEPN EXPENSE-ELEC	3390001	LAND RIGHTS - OTHER REN	SG	317.44	4	88	23	42	142	18	0	-
4030000	DEPN EXPENSE-ELEC	3390002	STRUCTURES AND IMPROVEMENTS - OTHER REN	SG	123.93	2	34	9	16	55	7	0	-
4030000	DEPN EXPENSE-ELEC	3390003	FUEL HOLDERS - OTHER REN	SG	1,164.11	16	323	85	155	519	66	0	-
4030000	DEPN EXPENSE-ELEC	3390004	BOILER PLANT EQUIPMENT - OTHER REN	SG	40.71	1	11	3	5	18	2	0	-
4030000	DEPN EXPENSE-ELEC	3390006	GENERATORS - OTHER REN	SG	676.74	9	188	50	90	302	38	0	-
4030000	DEPN EXPENSE-ELEC	3390008	ACCESSORY ELECTRIC EQUIPMENT - OTHER REN	SG	135.12	2	38	10	18	60	8	0	-
4030000	DEPN EXPENSE-ELEC	3390009	COMPUTER HARDWARE - OTHER REN	SG	0.46	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELEC	3390011	COMMUNICATION EQUIPMENT - OTHER REN	SG	19.40	0	5	1	3	9	1	0	-
4030000	DEPN EXPENSE-ELEC	3390012	MISC POWER PLANT EQUIP - OTHER REN	SG	26.76	0	7	2	4	12	2	0	-
4030000	DEPN EXPENSE-ELEC	3390015	COMM EQUIP - MOBILE RADIOS - OTHER REN	SG	0.93	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELEC	3402000	LAND RIGHTS	SG	173.40	2	48	13	23	77	10	0	-
4030000	DEPN EXPENSE-ELEC	3410000	STRUCTURES & IMPROVEMENTS	OR	0.09	-	0	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3410000	STRUCTURES & IMPROVEMENTS	SG	6,425.93	89	1,784	471	855	2,865	362	0	-
4030000	DEPN EXPENSE-ELEC	3410000	STRUCTURES & IMPROVEMENTS	UT	1.58	-	-	-	-	2	-	-	-
4030000	DEPN EXPENSE-ELEC	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	540.92	7	150	40	72	241	30	0	-
4030000	DEPN EXPENSE-ELEC	3430000	PRIME MOVERS	SG	116,237.39	1,611	32,262	8,527	15,465	51,826	6,541	5	-
4030000	DEPN EXPENSE-ELEC	3440000	GENERATORS	SG	18,609.90	258	5,165	1,365	2,476	8,298	1,047	1	-
4030000	DEPN EXPENSE-ELEC	3440000	GENERATORS	UT	10.35	-	-	-	-	10	-	-	-
4030000	DEPN EXPENSE-ELEC	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	10,453.19	145	2,901	767	1,391	4,661	588	0	-
4030000	DEPN EXPENSE-ELEC	3450000	ACCESSORY ELECTRIC EQUIPMENT	UT	2.02	-	-	-	-	2	-	-	-
4030000	DEPN EXPENSE-ELEC	3451000	COMPUTER HARDWARE - OTHER PROD	SG	20.40	0	6	1	3	9	1	0	-
4030000	DEPN EXPENSE-ELEC	3452000	COMPUTER SOFTWARE (MISC) - OTHER PROD	SG	1.47	0	0	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3453000	COMMUNICATION EQUIPMENT - OTHER PROD	SG	50.88	1	14	4	7	23	3	0	-
4030000	DEPN EXPENSE-ELEC	3453005	COMM EQUIP - MOBILE RADIOS - OTHER PROD	SG	2.77	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	601.47	8	167	44	80	268	34	0	-
4030000	DEPN EXPENSE-ELEC	3502000	LAND RIGHTS	SG	3,371.24	47	936	247	449	1,503	190	0	-
4030000	DEPN EXPENSE-ELEC	3511000	COMPUTER HARDWARE - TRANS	SG	6.13	0	2	0	1	3	0	0	-
4030000	DEPN EXPENSE-ELEC	3512000	COMPUTER SOFTWARE (MISC) - TRANS	SG	0.87	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELEC	3512001	MONARCH EMS/SCADA	SG	2,178.47	30	605	160	290	971	123	0	-
4030000	DEPN EXPENSE-ELEC	3512003	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	11.85	0	3	1	2	5	1	0	-
4030000	DEPN EXPENSE-ELEC	3513000	COMMUNICATION EQUIPMENT - TRANS	SG	4,522.42	63	1,255	332	602	2,016	254	0	-
4030000	DEPN EXPENSE-ELEC	3513005	COMM EQUIP - MOBILE RADIOS - TRANS	SG	1.98	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3520000	STRUCTURES & IMPROVEMENTS	SG	5,768.65	80	1,601	423	767	2,572	325	0	-

PACIFICORP

Depreciation Expense (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELEC	3530000	STATION EQUIPMENT	SG	47,302.15	656	13,129	3,470	6,293	21,090	2,662	2	-
4030000	DEPN EXPENSE-ELEC	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	3,238.25	45	899	238	431	1,444	182	0	-
4030000	DEPN EXPENSE-ELEC	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	487.01	7	135	36	65	217	27	0	-
4030000	DEPN EXPENSE-ELEC	3540000	TOWERS AND FIXTURES	SG	26,685.30	370	7,407	1,958	3,550	11,898	1,502	1	-
4030000	DEPN EXPENSE-ELEC	3550000	POLES AND FIXTURES	SG	30,266.17	420	8,401	2,220	4,027	13,495	1,703	1	-
4030000	DEPN EXPENSE-ELEC	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	34,862.13	483	9,676	2,557	4,638	15,544	1,962	1	-
4030000	DEPN EXPENSE-ELEC	3570000	UNDERGROUND CONDUIT	SG	60.93	1	17	4	8	27	3	0	-
4030000	DEPN EXPENSE-ELEC	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	146.25	2	41	11	19	65	8	0	-
4030000	DEPN EXPENSE-ELEC	3590000	ROADS AND TRAILS	SG	146.91	2	41	11	20	66	8	0	-
4030000	DEPN EXPENSE-ELEC	3602000	LAND RIGHTS	CA	15.05	15	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3602000	LAND RIGHTS	IDU	28.39	-	-	-	-	-	28	-	-
4030000	DEPN EXPENSE-ELEC	3602000	LAND RIGHTS	OR	74.50	-	75	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3602000	LAND RIGHTS	UT	209.14	-	-	-	-	209	-	-	-
4030000	DEPN EXPENSE-ELEC	3602000	LAND RIGHTS	WA	10.06	-	-	10	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3602000	LAND RIGHTS	WYP	90.53	-	-	-	91	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3602000	LAND RIGHTS	WYU	125.42	-	-	-	125	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3610000	STRUCTURES & IMPROVEMENTS	CA	176.52	177	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3610000	STRUCTURES & IMPROVEMENTS	IDU	65.80	-	-	-	-	-	66	-	-
4030000	DEPN EXPENSE-ELEC	3610000	STRUCTURES & IMPROVEMENTS	OR	602.54	-	603	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3610000	STRUCTURES & IMPROVEMENTS	UT	1,327.49	-	-	-	-	1,327	-	-	-
4030000	DEPN EXPENSE-ELEC	3610000	STRUCTURES & IMPROVEMENTS	WA	145.12	-	-	145	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3610000	STRUCTURES & IMPROVEMENTS	WYP	328.08	-	-	-	328	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3610000	STRUCTURES & IMPROVEMENTS	WYU	79.47	-	-	-	79	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3620000	STATION EQUIPMENT	CA	1,117.62	1,118	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3620000	STATION EQUIPMENT	IDU	964.47	-	-	-	-	-	964	-	-
4030000	DEPN EXPENSE-ELEC	3620000	STATION EQUIPMENT	OR	6,526.64	-	6,527	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3620000	STATION EQUIPMENT	UT	14,343.54	-	-	-	-	14,344	-	-	-
4030000	DEPN EXPENSE-ELEC	3620000	STATION EQUIPMENT	WA	2,063.50	-	-	2,064	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3620000	STATION EQUIPMENT	WYP	2,686.57	-	-	-	2,687	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3620000	STATION EQUIPMENT	WYU	374.00	-	-	-	374	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	22.74	23	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	11.61	-	-	-	-	-	12	-	-
4030000	DEPN EXPENSE-ELEC	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	97.72	-	98	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	194.74	-	-	-	-	195	-	-	-
4030000	DEPN EXPENSE-ELEC	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	37.18	-	-	37	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	42.37	-	-	-	42	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	6.20	-	-	-	6	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3631000	COMPUTER HARDWARE - DIST	CA	2.93	3	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3631000	COMPUTER HARDWARE - DIST	IDU	23.67	-	-	-	-	-	24	-	-
4030000	DEPN EXPENSE-ELEC	3631000	COMPUTER HARDWARE - DIST	OR	51.50	-	51	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3631000	COMPUTER HARDWARE - DIST	UT	42.59	-	-	-	-	43	-	-	-
4030000	DEPN EXPENSE-ELEC	3631000	COMPUTER HARDWARE - DIST	WA	30.81	-	-	31	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3631000	COMPUTER HARDWARE - DIST	WYP	82.19	-	-	-	82	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3631000	COMPUTER HARDWARE - DIST	WYU	5.11	-	-	-	5	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3632000	COMPUTER SOFTWARE (MISC) - DIST	OR	8.18	-	8	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3632000	COMPUTER SOFTWARE (MISC) - DIST	UT	0.11	-	-	-	-	0	-	-	-
4030000	DEPN EXPENSE-ELEC	3632000	COMPUTER SOFTWARE (MISC) - DIST	WA	0.06	-	-	0	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3632000	COMPUTER SOFTWARE (MISC) - DIST	WYP	7.47	-	-	-	7	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3632004	ARCOS	SNPD	301.24	24	77	15	24	147	14	-	-
4030000	DEPN EXPENSE-ELEC	3632010	GWD - GRAPHICAL WORK DESIGN	SNPD	309.10	25	79	16	25	151	14	-	-
4030000	DEPN EXPENSE-ELEC	3633000	COMMUNICATION EQUIPMENT - DIST	CA	182.44	182	-	-	-	-	-	-	-

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Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELEC	3633000	COMMUNICATION EQUIPMENT - DIST	IDU	200.55	-	-	-	-	-	201	-	-
4030000	DEPN EXPENSE-ELEC	3633000	COMMUNICATION EQUIPMENT - DIST	OR	1,233.88	-	1,234	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3633000	COMMUNICATION EQUIPMENT - DIST	SNPD	2.09	0	1	0	0	1	0	-	-
4030000	DEPN EXPENSE-ELEC	3633000	COMMUNICATION EQUIPMENT - DIST	UT	1,057.36	-	-	-	-	1,057	-	-	-
4030000	DEPN EXPENSE-ELEC	3633000	COMMUNICATION EQUIPMENT - DIST	WA	164.46	-	-	164	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3633000	COMMUNICATION EQUIPMENT - DIST	WYP	340.53	-	-	-	341	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3633000	COMMUNICATION EQUIPMENT - DIST	WYU	65.96	-	-	-	66	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3633005	COMM EQUIP - MOBILE RADIOS - DIST	CA	0.41	0	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3633005	COMM EQUIP - MOBILE RADIOS - DIST	IDU	4.32	-	-	-	-	-	4	-	-
4030000	DEPN EXPENSE-ELEC	3633005	COMM EQUIP - MOBILE RADIOS - DIST	OR	0.95	-	1	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3633005	COMM EQUIP - MOBILE RADIOS - DIST	UT	18.71	-	-	-	-	19	-	-	-
4030000	DEPN EXPENSE-ELEC	3633005	COMM EQUIP - MOBILE RADIOS - DIST	WA	0.13	-	-	0	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3633005	COMM EQUIP - MOBILE RADIOS - DIST	WYP	5.15	-	-	-	5	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3633005	COMM EQUIP - MOBILE RADIOS - DIST	WYU	1.54	-	-	-	2	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3640000	"POLES, TOWERS AND FIXTURES"	CA	6,206.86	6,207	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3640000	"POLES, TOWERS AND FIXTURES"	IDU	4,157.51	-	-	-	-	-	4,158	-	-
4030000	DEPN EXPENSE-ELEC	3640000	"POLES, TOWERS AND FIXTURES"	OR	18,675.11	-	18,675	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3640000	"POLES, TOWERS AND FIXTURES"	UT	19,275.34	-	-	-	-	19,275	-	-	-
4030000	DEPN EXPENSE-ELEC	3640000	"POLES, TOWERS AND FIXTURES"	WA	5,173.37	-	-	5,173	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3640000	"POLES, TOWERS AND FIXTURES"	WYP	5,693.42	-	-	-	5,693	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3640000	"POLES, TOWERS AND FIXTURES"	WYU	1,109.19	-	-	-	1,109	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	3,140.08	3,140	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	1,143.78	-	-	-	-	-	1,144	-	-
4030000	DEPN EXPENSE-ELEC	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	8,329.98	-	8,330	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	8,527.15	-	-	-	-	8,527	-	-	-
4030000	DEPN EXPENSE-ELEC	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	2,692.45	-	-	2,692	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	2,988.59	-	-	-	2,989	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	382.13	-	-	-	382	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3660000	UNDERGROUND CONDUIT	CA	548.52	549	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3660000	UNDERGROUND CONDUIT	IDU	390.23	-	-	-	-	-	390	-	-
4030000	DEPN EXPENSE-ELEC	3660000	UNDERGROUND CONDUIT	OR	2,279.02	-	2,279	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3660000	UNDERGROUND CONDUIT	UT	7,177.96	-	-	-	-	7,178	-	-	-
4030000	DEPN EXPENSE-ELEC	3660000	UNDERGROUND CONDUIT	WA	611.56	-	-	612	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3660000	UNDERGROUND CONDUIT	WYP	951.58	-	-	-	952	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3660000	UNDERGROUND CONDUIT	WYU	164.59	-	-	-	165	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	613.58	614	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	712.41	-	-	-	-	-	712	-	-
4030000	DEPN EXPENSE-ELEC	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	5,003.65	-	5,004	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	15,359.19	-	-	-	-	15,359	-	-	-
4030000	DEPN EXPENSE-ELEC	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	836.02	-	-	836	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	1,438.46	-	-	-	1,438	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	517.76	-	-	-	518	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3680000	LINE TRANSFORMERS	CA	1,542.25	1,542	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3680000	LINE TRANSFORMERS	IDU	2,204.40	-	-	-	-	-	2,204	-	-
4030000	DEPN EXPENSE-ELEC	3680000	LINE TRANSFORMERS	OR	12,834.27	-	12,834	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3680000	LINE TRANSFORMERS	UT	17,260.81	-	-	-	-	17,261	-	-	-
4030000	DEPN EXPENSE-ELEC	3680000	LINE TRANSFORMERS	WA	3,249.77	-	-	3,250	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3680000	LINE TRANSFORMERS	WYP	3,667.19	-	-	-	3,667	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3680000	LINE TRANSFORMERS	WYU	505.87	-	-	-	506	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3691000	SERVICES - OVERHEAD	CA	350.03	350	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3691000	SERVICES - OVERHEAD	IDU	248.56	-	-	-	-	-	249	-	-

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Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELEC	3691000	SERVICES - OVERHEAD	OR	2,520.36	-	2,520	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3691000	SERVICES - OVERHEAD	UT	2,702.26	-	-	-	-	2,702	-	-	-
4030000	DEPN EXPENSE-ELEC	3691000	SERVICES - OVERHEAD	WA	657.77	-	-	658	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3691000	SERVICES - OVERHEAD	WYP	483.40	-	-	-	483	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3691000	SERVICES - OVERHEAD	WYU	112.24	-	-	-	112	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3692000	SERVICES - UNDERGROUND	CA	484.63	485	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3692000	SERVICES - UNDERGROUND	IDU	1,066.53	-	-	-	-	-	1,067	-	-
4030000	DEPN EXPENSE-ELEC	3692000	SERVICES - UNDERGROUND	OR	5,480.57	-	5,481	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3692000	SERVICES - UNDERGROUND	UT	8,234.72	-	-	-	-	8,235	-	-	-
4030000	DEPN EXPENSE-ELEC	3692000	SERVICES - UNDERGROUND	WA	1,380.48	-	-	1,380	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3692000	SERVICES - UNDERGROUND	WYP	1,302.89	-	-	-	1,303	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3692000	SERVICES - UNDERGROUND	WYU	442.70	-	-	-	443	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3700000	METERS	CA	461.29	461	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3700000	METERS	IDU	898.58	-	-	-	-	-	899	-	-
4030000	DEPN EXPENSE-ELEC	3700000	METERS	OR	1,894.19	-	1,894	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3700000	METERS	UT	8,741.57	-	-	-	-	8,742	-	-	-
4030000	DEPN EXPENSE-ELEC	3700000	METERS	WA	855.69	-	-	856	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3700000	METERS	WYP	829.05	-	-	-	829	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3700000	METERS	WYU	165.10	-	-	-	165	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3710000	INSTALL ON CUSTOMERS PREMISES	CA	14.81	15	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	7.70	-	-	-	-	-	8	-	-
4030000	DEPN EXPENSE-ELEC	3710000	INSTALL ON CUSTOMERS PREMISES	OR	118.89	-	119	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3710000	INSTALL ON CUSTOMERS PREMISES	UT	265.48	-	-	-	-	265	-	-	-
4030000	DEPN EXPENSE-ELEC	3710000	INSTALL ON CUSTOMERS PREMISES	WA	21.27	-	-	21	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	32.22	-	-	-	32	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	5.35	-	-	-	5	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	160.02	160	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	36.28	-	-	-	-	-	36	-	-
4030000	DEPN EXPENSE-ELEC	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	632.20	-	632	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	1,136.07	-	-	-	-	1,136	-	-	-
4030000	DEPN EXPENSE-ELEC	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	116.90	-	-	117	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	254.63	-	-	-	255	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	64.13	-	-	-	64	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3892000	LAND RIGHTS	IDU	0.08	-	-	-	-	-	0	-	-
4030000	DEPN EXPENSE-ELEC	3892000	LAND RIGHTS	OR	0.02	-	0	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3892000	LAND RIGHTS	SG	0.03	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELEC	3892000	LAND RIGHTS	SO	2.38	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3892000	LAND RIGHTS	UT	1.96	-	-	-	-	2	-	-	-
4030000	DEPN EXPENSE-ELEC	3892000	LAND RIGHTS	WYP	0.98	-	-	-	1	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3892000	LAND RIGHTS	WYU	0.41	-	-	-	0	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3900000	STRUCTURES AND IMPROVEMENTS	CA	78.03	78	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3900000	STRUCTURES AND IMPROVEMENTS	CN	209.58	5	63	14	14	104	9	-	-
4030000	DEPN EXPENSE-ELEC	3900000	STRUCTURES AND IMPROVEMENTS	IDU	247.36	-	-	-	-	-	247	-	-
4030000	DEPN EXPENSE-ELEC	3900000	STRUCTURES AND IMPROVEMENTS	OR	803.28	-	803	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3900000	STRUCTURES AND IMPROVEMENTS	SE	23.99	0	6	2	3	11	1	0	-
4030000	DEPN EXPENSE-ELEC	3900000	STRUCTURES AND IMPROVEMENTS	SG	278.21	4	77	20	37	124	16	0	-
4030000	DEPN EXPENSE-ELEC	3900000	STRUCTURES AND IMPROVEMENTS	SO	2,568.44	78	717	180	312	1,143	138	0	-
4030000	DEPN EXPENSE-ELEC	3900000	STRUCTURES AND IMPROVEMENTS	UT	1,240.05	-	-	-	-	1,240	-	-	-
4030000	DEPN EXPENSE-ELEC	3900000	STRUCTURES AND IMPROVEMENTS	WA	245.72	-	-	246	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3900000	STRUCTURES AND IMPROVEMENTS	WYP	359.64	-	-	-	360	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3900000	STRUCTURES AND IMPROVEMENTS	WYU	122.55	-	-	-	123	-	-	-	-

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Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELEC	3910000	OFFICE FURNITURE	CA	1.44	1	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3910000	OFFICE FURNITURE	CN	11.02	0	3	1	1	5	0	-	-
4030000	DEPN EXPENSE-ELEC	3910000	OFFICE FURNITURE	IDU	3.47	-	-	-	-	-	3	-	-
4030000	DEPN EXPENSE-ELEC	3910000	OFFICE FURNITURE	OR	54.69	-	55	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3910000	OFFICE FURNITURE	SE	0.19	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELEC	3910000	OFFICE FURNITURE	SG	100.89	1	28	7	13	45	6	0	-
4030000	DEPN EXPENSE-ELEC	3910000	OFFICE FURNITURE	SO	727.84	22	203	51	88	324	39	0	-
4030000	DEPN EXPENSE-ELEC	3910000	OFFICE FURNITURE	UT	50.29	-	-	-	-	50	-	-	-
4030000	DEPN EXPENSE-ELEC	3910000	OFFICE FURNITURE	WA	2.43	-	-	2	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3910000	OFFICE FURNITURE	WYP	24.71	-	-	-	25	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3910000	OFFICE FURNITURE	WYU	2.21	-	-	-	2	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTER	CA	5.34	5	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTER	CN	226.61	5	68	16	16	112	10	-	-
4030000	DEPN EXPENSE-ELEC	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTER	IDU	40.43	-	-	-	-	-	40	-	-
4030000	DEPN EXPENSE-ELEC	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTER	OR	87.95	-	88	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTER	SE	2.35	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTER	SG	151.82	2	42	11	20	68	9	0	-
4030000	DEPN EXPENSE-ELEC	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTER	SO	5,872.80	178	1,639	412	714	2,614	316	0	-
4030000	DEPN EXPENSE-ELEC	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTER	UT	74.02	-	-	-	-	74	-	-	-
4030000	DEPN EXPENSE-ELEC	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTER	WA	39.98	-	-	40	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTER	WYP	123.17	-	-	-	123	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTER	WYU	7.58	-	-	-	8	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3913000	OFFICE EQUIPMENT	CN	0.05	0	0	0	0	0	0	-	-
4030000	DEPN EXPENSE-ELEC	3913000	OFFICE EQUIPMENT	OR	0.01	-	0	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3913000	OFFICE EQUIPMENT	SG	2.87	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3913000	OFFICE EQUIPMENT	SO	91.65	3	26	6	11	41	5	0	-
4030000	DEPN EXPENSE-ELEC	3913000	OFFICE EQUIPMENT	UT	0.97	-	-	-	-	1	-	-	-
4030000	DEPN EXPENSE-ELEC	3913000	OFFICE EQUIPMENT	WYU	1.03	-	-	-	1	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3930000	STORES EQUIPMENT	CA	4.33	4	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3930000	STORES EQUIPMENT	IDU	47.36	-	-	-	-	-	47	-	-
4030000	DEPN EXPENSE-ELEC	3930000	STORES EQUIPMENT	OR	161.19	-	161	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3930000	STORES EQUIPMENT	SG	307.29	4	85	23	41	137	17	0	-
4030000	DEPN EXPENSE-ELEC	3930000	STORES EQUIPMENT	SO	11.34	0	3	1	1	5	1	0	-
4030000	DEPN EXPENSE-ELEC	3930000	STORES EQUIPMENT	UT	165.81	-	-	-	-	166	-	-	-
4030000	DEPN EXPENSE-ELEC	3930000	STORES EQUIPMENT	WA	40.19	-	-	40	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3930000	STORES EQUIPMENT	WYP	58.94	-	-	-	59	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3930000	STORES EQUIPMENT	WYU	0.05	-	-	-	0	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	46.66	47	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	97.28	-	-	-	-	-	97	-	-
4030000	DEPN EXPENSE-ELEC	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	437.46	-	437	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	3.95	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELEC	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	944.92	13	262	69	126	421	53	0	-
4030000	DEPN EXPENSE-ELEC	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	70.85	2	20	5	9	32	4	0	-
4030000	DEPN EXPENSE-ELEC	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	676.25	-	-	-	-	676	-	-	-
4030000	DEPN EXPENSE-ELEC	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	120.21	-	-	120	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	172.35	-	-	-	172	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	9.69	-	-	-	10	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3950000	LABORATORY EQUIPMENT	CA	39.34	39	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3950000	LABORATORY EQUIPMENT	IDU	71.92	-	-	-	-	-	72	-	-
4030000	DEPN EXPENSE-ELEC	3950000	LABORATORY EQUIPMENT	OR	529.44	-	529	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3950000	LABORATORY EQUIPMENT	SE	56.73	1	15	4	8	25	3	0	-

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Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELEC	3950000	LABORATORY EQUIPMENT	SG	328.40	5	91	24	44	146	18	0	-
4030000	DEPN EXPENSE-ELEC	3950000	LABORATORY EQUIPMENT	SO	224.46	7	63	16	27	100	12	0	-
4030000	DEPN EXPENSE-ELEC	3950000	LABORATORY EQUIPMENT	UT	497.00	-	-	-	-	497	-	-	-
4030000	DEPN EXPENSE-ELEC	3950000	LABORATORY EQUIPMENT	WA	72.35	-	-	72	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3950000	LABORATORY EQUIPMENT	WYP	169.85	-	-	-	170	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3950000	LABORATORY EQUIPMENT	WYU	4.33	-	-	-	4	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3970000	COMMUNICATION EQUIPMENT	CA	173.83	174	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3970000	COMMUNICATION EQUIPMENT	CN	76.11	2	23	5	5	38	3	-	-
4030000	DEPN EXPENSE-ELEC	3970000	COMMUNICATION EQUIPMENT	IDU	289.63	-	-	-	-	-	290	-	-
4030000	DEPN EXPENSE-ELEC	3970000	COMMUNICATION EQUIPMENT	OR	1,569.51	-	1,570	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3970000	COMMUNICATION EQUIPMENT	SE	6.51	0	2	0	1	3	0	0	-
4030000	DEPN EXPENSE-ELEC	3970000	COMMUNICATION EQUIPMENT	SG	4,912.70	68	1,364	360	654	2,190	276	0	-
4030000	DEPN EXPENSE-ELEC	3970000	COMMUNICATION EQUIPMENT	SO	2,221.00	67	620	156	270	989	119	0	-
4030000	DEPN EXPENSE-ELEC	3970000	COMMUNICATION EQUIPMENT	UT	1,747.60	-	-	-	-	1,748	-	-	-
4030000	DEPN EXPENSE-ELEC	3970000	COMMUNICATION EQUIPMENT	WA	304.14	-	-	304	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3970000	COMMUNICATION EQUIPMENT	WYP	615.90	-	-	-	616	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3970000	COMMUNICATION EQUIPMENT	WYU	157.31	-	-	-	157	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3971001	COMPUTER HARDWARE - GENERAL	CN	168.32	4	51	12	12	83	7	-	-
4030000	DEPN EXPENSE-ELEC	3971001	COMPUTER HARDWARE - GENERAL	SE	0.87	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELEC	3971001	COMPUTER HARDWARE - GENERAL	SO	4,779.27	145	1,334	335	581	2,127	257	0	-
4030000	DEPN EXPENSE-ELEC	3971001	COMPUTER HARDWARE - GENERAL	UT	0.45	-	-	-	-	0	-	-	-
4030000	DEPN EXPENSE-ELEC	3971001	COMPUTER HARDWARE - GENERAL	WA	0.00	-	-	0	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3972000	MOBILE RADIO EQUIPMENT	CA	2.50	2	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3972000	MOBILE RADIO EQUIPMENT	IDU	5.11	-	-	-	-	-	5	-	-
4030000	DEPN EXPENSE-ELEC	3972000	MOBILE RADIO EQUIPMENT	OR	1.89	-	2	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3972000	MOBILE RADIO EQUIPMENT	SG	21.48	0	6	2	3	10	1	0	-
4030000	DEPN EXPENSE-ELEC	3972000	MOBILE RADIO EQUIPMENT	SO	2.21	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3972000	MOBILE RADIO EQUIPMENT	UT	22.96	-	-	-	-	23	-	-	-
4030000	DEPN EXPENSE-ELEC	3972000	MOBILE RADIO EQUIPMENT	WA	0.15	-	-	0	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3972000	MOBILE RADIO EQUIPMENT	WYP	6.08	-	-	-	6	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3972000	MOBILE RADIO EQUIPMENT	WYU	1.83	-	-	-	2	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3972001	COMPUTER SOFTWARE (MISC) - GENERAL	CN	2.19	0	1	0	0	1	0	-	-
4030000	DEPN EXPENSE-ELEC	3972001	COMPUTER SOFTWARE (MISC) - GENERAL	SE	0.76	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELEC	3972001	COMPUTER SOFTWARE (MISC) - GENERAL	SO	2,447.40	74	683	172	297	1,089	132	0	-
4030000	DEPN EXPENSE-ELEC	3972003	SAP - SAP	SO	2,529.63	77	706	178	307	1,126	136	0	-
4030000	DEPN EXPENSE-ELEC	3972004	VMWARE	SO	696.07	21	194	49	85	310	37	0	-
4030000	DEPN EXPENSE-ELEC	3972005	AUGMENTED REALITY	SO	1,542.93	47	431	108	187	687	83	0	-
4030000	DEPN EXPENSE-ELEC	3972011	CSS - CUSTOMER SERVICE SYSTEM	CN	201.11	4	61	14	14	100	9	-	-
4030000	DEPN EXPENSE-ELEC	3972013	NODAL PRICING SOFTWARE	SG	303.23	4	84	22	40	135	17	0	-
4030000	DEPN EXPENSE-ELEC	3972014	ESM-IRP	SO	380.46	12	106	27	46	169	20	0	-
4030000	DEPN EXPENSE-ELEC	3972015	CELONIS	SO	387.38	12	108	27	47	172	21	0	-
4030000	DEPN EXPENSE-ELEC	3972016	IAM - SCHEDULING/TAGGING SYSTEM	SO	125.15	4	35	9	15	56	7	0	-
4030000	DEPN EXPENSE-ELEC	3972017	AZURE B2C - IDENTITY MGT	SO	131.02	4	37	9	16	58	7	0	-
4030000	DEPN EXPENSE-ELEC	3972018	PCI GENTRADER	SO	9.43	0	3	1	1	4	1	0	-
4030000	DEPN EXPENSE-ELEC	3972019	ITOA	SO	428.22	13	120	30	52	191	23	0	-
4030000	DEPN EXPENSE-ELEC	3972020	TSSA - TRUESIGHT SERVER AUTOMATION	SO	146.62	4	41	10	18	65	8	0	-
4030000	DEPN EXPENSE-ELEC	3972023	AMBIENT AI	SO	60.18	2	17	4	7	27	3	0	-
4030000	DEPN EXPENSE-ELEC	3972026	SETTLECORE	SG	117.27	2	33	9	16	52	7	0	-
4030000	DEPN EXPENSE-ELEC	3972031	UII - UTILITY INTERNATIONAL FORECASTING	SO	1,046.31	32	292	73	127	466	56	0	-
4030000	DEPN EXPENSE-ELEC	3972035	VERVE OPERATIONAL TECHNOLOGY SYSTEM	SG	49.45	1	14	4	7	22	3	0	-
4030000	DEPN EXPENSE-ELEC	3972039	AMI METERING SOFTWARE	CN	2,298.67	50	693	158	159	1,140	99	-	-

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Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELEC	3972040	BIG DATA & ANALYTICS	SO	531.62	16	148	37	65	237	29	0	-
4030000	DEPN EXPENSE-ELEC	3972041	CES - CUSTOMER EXPERIENCE SYSTEM	CN	975.73	21	294	67	68	484	42	-	-
4030000	DEPN EXPENSE-ELEC	3972042	MAPAPPS - MAPPING SYSTEMS APPLICATION	SO	826.43	25	231	58	100	368	44	0	-
4030000	DEPN EXPENSE-ELEC	3972043	CUSTOMER CONTACTS	CN	358.04	8	108	25	25	178	15	-	-
4030000	DEPN EXPENSE-ELEC	3972045	C&T - ENERGY TRADING SYSTEM	SO	282.40	9	79	20	34	126	15	0	-
4030000	DEPN EXPENSE-ELEC	3972047	M365	SO	340.28	10	95	24	41	151	18	0	-
4030000	DEPN EXPENSE-ELEC	3972048	ADS	SO	353.63	11	99	25	43	157	19	0	-
4030000	DEPN EXPENSE-ELEC	3972049	TECHNOSYLVA	SO	3,503.60	106	978	246	426	1,559	188	0	-
4030000	DEPN EXPENSE-ELEC	3972050	SITUATIONAL AWARENESS	SO	112.49	3	31	8	14	50	6	0	-
4030000	DEPN EXPENSE-ELEC	3972051	MAXIMO	SO	979.21	30	273	69	119	436	53	0	-
4030000	DEPN EXPENSE-ELEC	3972052	AURORA	SO	177.74	5	50	12	22	79	10	0	-
4030000	DEPN EXPENSE-ELEC	3972053	CXP - CUSTOMER EXPERIENCE (CX) PLATFORM	CN	221.35	5	67	15	15	110	9	-	-
4030000	DEPN EXPENSE-ELEC	3972054	SOLARWINDS	SG	39.45	1	11	3	5	18	2	0	-
4030000	DEPN EXPENSE-ELEC	3972055	APIM - ASSET PERFORMANCE & INVESTMENT MA	SO	529.58	16	148	37	64	236	28	0	-
4030000	DEPN EXPENSE-ELEC	3972056	ENTERPRISE GEOGRAPHIC INFORMATION SYSTE	SO	106.38	3	30	7	13	47	6	0	-
4030000	DEPN EXPENSE-ELEC	3972057	FOUNDRY	SO	3,672.97	111	1,025	258	446	1,635	197	0	-
4030000	DEPN EXPENSE-ELEC	3972058	PSP - PUBLIC SAFETY PORTAL	SO	1,087.98	33	304	76	132	484	58	0	-
4030000	DEPN EXPENSE-ELEC	3973001	COMMUNICATION EQUIPMENT - GENERAL	CA	0.20	0	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3973001	COMMUNICATION EQUIPMENT - GENERAL	CN	61.89	1	19	4	4	31	3	-	-
4030000	DEPN EXPENSE-ELEC	3973001	COMMUNICATION EQUIPMENT - GENERAL	IDU	13.59	-	-	-	-	-	14	-	-
4030000	DEPN EXPENSE-ELEC	3973001	COMMUNICATION EQUIPMENT - GENERAL	OR	74.67	-	75	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3973001	COMMUNICATION EQUIPMENT - GENERAL	SE	5.13	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELEC	3973001	COMMUNICATION EQUIPMENT - GENERAL	SG	39.96	1	11	3	5	18	2	0	-
4030000	DEPN EXPENSE-ELEC	3973001	COMMUNICATION EQUIPMENT - GENERAL	SO	1,373.01	42	383	96	167	611	74	0	-
4030000	DEPN EXPENSE-ELEC	3973001	COMMUNICATION EQUIPMENT - GENERAL	UT	112.30	-	-	-	-	112	-	-	-
4030000	DEPN EXPENSE-ELEC	3973001	COMMUNICATION EQUIPMENT - GENERAL	WA	0.96	-	-	1	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3973001	COMMUNICATION EQUIPMENT - GENERAL	WYP	0.63	-	-	-	1	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3973001	COMMUNICATION EQUIPMENT - GENERAL	WYU	31.31	-	-	-	31	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3973005	COMM EQUIP - MOBILE RADIOS - GENERAL	SO	1.87	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELEC	3973005	COMM EQUIP - MOBILE RADIOS - GENERAL	UT	0.34	-	-	-	-	0	-	-	-
4030000	DEPN EXPENSE-ELEC	3980000	MISCELLANEOUS EQUIPMENT	CA	3.28	3	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3980000	MISCELLANEOUS EQUIPMENT	CN	3.93	0	1	0	0	2	0	-	-
4030000	DEPN EXPENSE-ELEC	3980000	MISCELLANEOUS EQUIPMENT	IDU	4.05	-	-	-	-	-	4	-	-
4030000	DEPN EXPENSE-ELEC	3980000	MISCELLANEOUS EQUIPMENT	OR	68.89	-	69	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3980000	MISCELLANEOUS EQUIPMENT	SE	0.11	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELEC	3980000	MISCELLANEOUS EQUIPMENT	SG	148.24	2	41	11	20	66	8	0	-
4030000	DEPN EXPENSE-ELEC	3980000	MISCELLANEOUS EQUIPMENT	SO	73.64	2	21	5	9	33	4	0	-
4030000	DEPN EXPENSE-ELEC	3980000	MISCELLANEOUS EQUIPMENT	UT	88.29	-	-	-	-	88	-	-	-
4030000	DEPN EXPENSE-ELEC	3980000	MISCELLANEOUS EQUIPMENT	WA	10.48	-	-	10	-	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3980000	MISCELLANEOUS EQUIPMENT	WYP	13.65	-	-	-	14	-	-	-	-
4030000	DEPN EXPENSE-ELEC	3980000	MISCELLANEOUS EQUIPMENT	WYU	1.27	-	-	-	1	-	-	-	-
4030000 Total					**1,079,298.01**	**27,563**	**299,042**	**79,168**	**136,070**	**478,238**	**59,185**	**33**	**-**
4032000	DEPR - STEAM	565131	DEPR - PROD STEAM NOT CLASSIFIED	SG	1,854.92	26	515	136	247	827	104	0	-
4032000	DEPR - STEAM	565247	Depr - Prod Steam UT STEP	OTHER	77,177.36	-	-	-	-	-	-	-	77,177
4032000 Total					**79,032.28**	**26**	**515**	**136**	**247**	**827**	**104**	**0**	**77,177**
4032050	DEPR - OTH REN	565137	Depr - Other Renewables Not Classified	SG	10.43	0	3	1	1	5	1	0	-
4032050 Total					**10.43**	**0**	**3**	**1**	**1**	**5**	**1**	**0**	**-**
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-P	(385.08)	(5)	(107)	(28)	(51)	(172)	(22)	(0)	-
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-U	359.10	5	100	26	48	160	20	0	-
4033000 Total					**(25.99)**	**(0)**	**(7)**	**(2)**	**(3)**	**(12)**	**(1)**	**(0)**	**-**
4033050	DEPR - WIND	565248	Depr - Wind Not Classified	SG	2,714.21	38	753	199	361	1,210	153	0	-

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Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4033050 Total					**2,714.21**	**38**	**753**	**199**	**361**	**1,210**	**153**	**0**	**-**
4034000	DEPR - OTHER	565134	DEPR - PROD OTHER NOT CLASSIFIED	SG	1,296.15	18	360	95	172	578	73	0	-
4034000 Total					**1,296.15**	**18**	**360**	**95**	**172**	**578**	**73**	**0**	**-**
4034050	DEPR - SOLAR	565249	Depr - Solar Not Classified	OR	0.15	-	0	-	-	-	-	-	-
4034050 Total					**0.15**	**-**	**0**	**-**	**-**	**-**	**-**	**-**	**-**
4035000	DEPR-TRANSMISSION	565141	DEPR - TRANS ASSETS NOT CLASSIFIED	SG	21,350.82	296	5,926	1,566	2,841	9,520	1,201	1	-
4035000	DEPR-TRANSMISSION	565144	Depr - Transm - OR Adjustment	OTHER	(1,001.44)	-	-	-	-	-	-	-	(1,001)
4035000 Total					**20,349.38**	**296**	**5,926**	**1,566**	**2,841**	**9,520**	**1,201**	**1**	**(1,001)**
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	CA	722.29	722	-	-	-	-	-	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	IDU	218.72	-	-	-	-	-	219	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	OR	2,374.60	-	2,375	-	-	-	-	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	SG	1.46	0	0	0	0	1	0	0	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	UT	2,892.95	-	-	-	-	2,893	-	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WA	246.69	-	-	247	-	-	-	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WYP	324.14	-	-	-	324	-	-	-	-
4036000	DEPR-DISTRIBUTION	565162	Depr - Dist - CA Adjustment	CA	51.16	51	-	-	-	-	-	-	-
4036000	DEPR-DISTRIBUTION	565164	Depr - Dist - OR Adjustment	OTHER	(2,576.13)	-	-	-	-	-	-	-	(2,576)
4036000 Total					**4,255.88**	**773**	**2,375**	**247**	**324**	**2,894**	**219**	**0**	**(2,576)**
4037000	DEPR - GENERAL	565201	DEPR - GEN ASSETS NOT CLASSIFIED	SG	7,835.92	109	2,175	575	1,043	3,494	441	0	-
4037000 Total					**7,835.92**	**109**	**2,175**	**575**	**1,043**	**3,494**	**441**	**0**	**-**
4039999	DEPR EXP-ELEC, OTH	565970	DEPRECIATION-JOINT OWNER BILLED-CREDIT	SG	(257.21)	(4)	(71)	(19)	(34)	(115)	(14)	(0)	-
4039999 Total					**(257.21)**	**(4)**	**(71)**	**(19)**	**(34)**	**(115)**	**(14)**	**(0)**	**-**
Grand Total					**1,194,509.23**	**28,819**	**311,070**	**81,966**	**141,021**	**496,639**	**61,360**	**34**	**73,600**

B4. AMORTIZATION EXPENSE

PACIFICORP

Amortization Expense (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG	1,247	17	346	91	166	556	70	0	-
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-P	2,683	37	745	197	357	1,196	151	0	-
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-U	263	4	73	19	35	117	15	0	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	OR	9	-	9	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	SG	1,136	16	315	83	151	507	64	0	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	UT	96	-	-	-	-	96	-	-	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	WYP	59	-	-	-	59	-	-	-	-
4040000	AMOR LTD TRM PLNT	3031680	CADOPS - COMPUTER-ASSISTED DISTRIBUTION	SO	424	13	118	30	52	189	23	0	-
4040000	AMOR LTD TRM PLNT	3031830	CUSTOMER SERVICE SYSTEM	CN	1,552	34	468	107	107	770	67	-	-
4040000	AMOR LTD TRM PLNT	3032040	SAP	SO	2,932	89	818	206	356	1,305	158	0	-
4040000	AMOR LTD TRM PLNT	3032130	NODAL PRICING SOFTWARE	SG	358	5	99	26	48	160	20	0	-
4040000	AMOR LTD TRM PLNT	3032140	ESM-IRP	SO	450	14	125	32	55	200	24	0	-
4040000	AMOR LTD TRM PLNT	3032150	CELONIS	SO	458	14	128	32	56	204	25	0	-
4040000	AMOR LTD TRM PLNT	3032160	ARCOS	SO	337	10	94	24	41	150	18	0	-
4040000	AMOR LTD TRM PLNT	3032170	AZURE B2C - IDENTITY MGT	SO	155	5	43	11	19	69	8	0	-
4040000	AMOR LTD TRM PLNT	3032180	IAM - SCHEDULING/TAGGING SYSTEM	SO	148	4	41	10	18	66	8	0	-
4040000	AMOR LTD TRM PLNT	3032190	4040000/3032190	SO	17	1	5	1	2	8	1	0	-
4040000	AMOR LTD TRM PLNT	3032200	ITOA	SO	475	14	133	33	58	211	26	0	-
4040000	AMOR LTD TRM PLNT	3032210	FACILITY INSPECTION REPORTING SYS	SO	173	5	48	12	21	77	9	0	-
4040000	AMOR LTD TRM PLNT	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	2	0	1	0	0	1	0	0	-
4040000	AMOR LTD TRM PLNT	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	3	0	1	0	0	1	0	0	-
4040000	AMOR LTD TRM PLNT	3032640	TIBCO SOFTWARE	SO	290	9	81	20	35	129	16	0	-
4040000	AMOR LTD TRM PLNT	3032690	UTILITY INTERNATIONAL FORECASTING MODEL	SO	1,157	35	323	81	141	515	62	0	-
4040000	AMOR LTD TRM PLNT	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	7	0	2	0	1	3	0	0	-
4040000	AMOR LTD TRM PLNT	3032740	GADSBY INTANGIBLE ASSETS	SG	4	0	1	0	0	2	0	0	-
4040000	AMOR LTD TRM PLNT	3032760	SWIFT 2 IMPROVEMENTS	SG	432	6	120	32	57	193	24	0	-
4040000	AMOR LTD TRM PLNT	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	24	0	7	2	3	11	1	0	-
4040000	AMOR LTD TRM PLNT	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	2	0	1	0	0	1	0	0	-
4040000	AMOR LTD TRM PLNT	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG-U	1	0	0	0	0	0	0	0	-
4040000	AMOR LTD TRM PLNT	3032860	WEB SOFTWARE	SO	78	2	22	5	9	35	4	0	-
4040000	AMOR LTD TRM PLNT	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSET	SG	360	5	100	26	48	160	20	0	-
4040000	AMOR LTD TRM PLNT	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	2,392	33	664	175	318	1,067	135	0	-
4040000	AMOR LTD TRM PLNT	3033220	MONARCH EMS/SCADA	SO	2,449	74	683	172	297	1,090	132	0	-
4040000	AMOR LTD TRM PLNT	3033250	AMI Metering Software	CN	2,712	60	817	186	188	1,345	116	-	-
4040000	AMOR LTD TRM PLNT	3033260	Big Data & Analytics	SO	293	9	82	21	36	130	16	0	-
4040000	AMOR LTD TRM PLNT	3033270	CES - Customer Experience System	CN	1,153	25	348	79	80	572	49	-	-
4040000	AMOR LTD TRM PLNT	3033280	MAPAPPS - Mapping Systems Application	SO	977	30	273	69	119	435	53	0	-
4040000	AMOR LTD TRM PLNT	3033290	CUSTOMER CONTACTS	CN	423	9	128	29	29	210	18	-	-
4040000	AMOR LTD TRM PLNT	3033310	C&T - ENERGY TRADING SYSTEM	SO	179	5	50	13	22	80	10	0	-
4040000	AMOR LTD TRM PLNT	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SO	8	0	2	1	1	4	0	0	-
4040000	AMOR LTD TRM PLNT	3033410	M365	SO	402	12	112	28	49	179	22	0	-
4040000	AMOR LTD TRM PLNT	3033420	SUBSTATION RELIABILITY SOFTWARE	SO	405	12	113	28	49	180	22	0	-
4040000	AMOR LTD TRM PLNT	3033430	DEPLOY DISTRIBUTION MGMT SYSTEM	SO	195	6	55	14	24	87	10	0	-
4040000	AMOR LTD TRM PLNT	3033440	DISTRIBUTION ENGINEERING COSTS	SO	127	4	35	9	15	56	7	0	-
4040000	AMOR LTD TRM PLNT	3033450	MAXIMO	SO	1,157	35	323	81	141	515	62	0	-
4040000	AMOR LTD TRM PLNT	3033460	AURORA	SO	206	6	58	14	25	92	11	0	-
4040000	AMOR LTD TRM PLNT	3033470	AUGMENTED REALITY	SO	1,288	39	359	90	156	573	69	0	-
4040000	AMOR LTD TRM PLNT	3033480	CXP	CN	262	6	79	18	18	130	11	-	-
4040000	AMOR LTD TRM PLNT	3033490	VMWARE	SO	823	25	230	58	100	366	44	0	-
4040000	AMOR LTD TRM PLNT	3033510	APIM	SO	695	21	194	49	84	309	37	0	-
4040000	AMOR LTD TRM PLNT	3033520	EGIS	SO	126	4	35	9	15	56	7	0	-
4040000	AMOR LTD TRM PLNT	3033530	SETTLECORE	SO	139	4	39	10	17	62	7	0	-

PACIFICORP

Amortization Expense (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4040000	AMOR LTD TRM PLNT	3033540	FOUNDRY	SO	4,507	137	1,258	316	548	2,006	242	0	-
4040000	AMOR LTD TRM PLNT	3033550	PSP - PUBLIC SAFETY PORTAL	SO	973	29	271	68	118	433	52	0	-
4040000	AMOR LTD TRM PLNT	3033560	VERVE OPERATIONAL TECHNOLOGY SYSTEM	SO	58	2	16	4	7	26	3	0	-
4040000	AMOR LTD TRM PLNT	3033570	PURCHASE SPINWARE SOFTWARE	SO	112	3	31	8	14	50	6	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	CN	3	0	1	0	0	1	0	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	OR	0	-	0	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SE	1	0	0	0	0	0	0	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SG	3,220	45	894	236	428	1,436	181	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SO	209	6	58	15	25	93	11	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	UT	0	-	-	-	-	0	-	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WA	0	-	-	0	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WYP	9	-	-	-	9	-	-	-	-
4040000	AMOR LTD TRM PLNT	3035320	HYDRO PLANT INTANGIBLES	SG	126	2	35	9	17	56	7	0	-
4040000	AMOR LTD TRM PLNT	3035320	HYDRO PLANT INTANGIBLES	SG-P	15	0	4	1	2	7	1	0	-
4040000	AMOR LTD TRM PLNT	3035330	OATI-OASIS INTERFACE	SO	32	1	9	2	4	14	2	0	-
4040000	AMOR LTD TRM PLNT	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	315	4	87	23	42	140	18	0	-
4040000	AMOR LTD TRM PLNT	3380018	INVERTERS - SOLAR - LSHLD IMPRV	OR	47	-	47	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3456000	Electric Equipment - Leasehold Improveme	OR	55	-	55	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	3	3	-	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	75	-	75	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	188	6	53	13	23	84	10	0	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	108	-	-	108	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	3	-	-	-	3	-	-	-	-
4040000 Total					**41,801**	**998**	**11,840**	**3,040**	**4,919**	**18,815**	**2,187**	**1**	**-**
4049000	AMR LTD TRM PLNT-OTH	566205	Amort Exp - Non-Rec	SO	(2,322)	(70)	(648)	(163)	(282)	(1,034)	(125)	(0)	-
4049000	AMR LTD TRM PLNT-OTH	566970	AMORTIZATION JO BILL CREDIT	SG	(409)	(6)	(114)	(30)	(54)	(182)	(23)	(0)	-
4049000 Total					**(2,731)**	**(76)**	**(762)**	**(193)**	**(337)**	**(1,216)**	**(148)**	**(0)**	**-**
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	SG	75	1	21	6	10	34	4	0	-
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	UT	302	-	-	-	-	302	-	-	-
4061000 Total					**377**	**1**	**21**	**6**	**10**	**335**	**4**	**0**	**-**
4073000	REGULATORY DEBITS	566909	Regulatory Debits O&M - 407.3	CA	3,455	3,455	-	-	-	-	-	-	-
4073000	REGULATORY DEBITS	566940	AMORT OF REG ASSETS - DEBITS	SG	1,384	19	384	102	184	617	78	0	-
4073000	REGULATORY DEBITS	566981	Amortz Reg A-Unrcvrd Plt/Decom Csts-CA	CA	1,264	1,264	-	-	-	-	-	-	-
4073000	REGULATORY DEBITS	566982	Amortz Reg A-Unrcvrd Plt/Decom Csts-ID	IDU	33	-	-	-	-	-	33	-	-
4073000	REGULATORY DEBITS	566983	Amortz Reg A-Unrcvrd Plt/Decom Csts-OR	OR	179	-	179	-	-	-	-	-	-
4073000	REGULATORY DEBITS	566984	Amortz Reg A-Unrcvrd Plt/Decom Csts-UT	UT	1,714	-	-	-	-	1,714	-	-	-
4073000	REGULATORY DEBITS	566986	Amortz Reg A-Unrcvrd Plt/Decom Csts-WY	WYP	4,794	-	-	-	4,794	-	-	-	-
4073000	REGULATORY DEBITS	566987	OR Wildfire-Damaged NBV Amortization	OTHER	126	-	-	-	-	-	-	-	126
4073000	REGULATORY DEBITS	566992	OR Meters Replaced by AMI Amortization	OTHER	3,993	-	-	-	-	-	-	-	3,993
4073000 Total					**16,942**	**4,738**	**564**	**102**	**4,978**	**2,330**	**111**	**0**	**4,119**
4074000	REGULATORY CREDITS	566990	UT Wildland Fire Mitigation - Deferral	OTHER	(4,654)	-	-	-	-	-	-	-	(4,654)
4074000	REGULATORY CREDITS	566993	CA Wildfire Mitigation Plan - Deferral	OTHER	(5,348)	-	-	-	-	-	-	-	(5,348)
4074000 Total					**(10,002)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(10,002)**
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	IDU	6,506	-	-	-	-	-	6,506	-	-
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	OR	49,393	-	49,393	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	WA	13,426	-	-	13,426	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	IDU	392	-	-	-	-	-	392	-	-
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	OR	1,030	-	1,030	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	WA	537	-	-	537	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	IDU	25	-	-	-	-	-	25	-	-
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	OR	1	-	1	-	-	-	-	-	-

PACIFICORP

Amortization Expense (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	WA	13	-	-	13	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	IDU	1,863	-	-	-	-	-	1,863	-	-
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	OR	834	-	834	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	WA	626	-	-	626	-	-	-	-	-
4074100 Total					**74,646**	**-**	**51,258**	**14,603**	**-**	**-**	**8,785**	**-**	**-**
4074200	Reg Credits-BPA Exch	505201	Regional Bill Intchg Rec/Del-OR (PP)	OR	(51,314)	-	(51,314)	-	-	-	-	-	-
4074200	Reg Credits-BPA Exch	505202	Regional Bill Intchg Rec/Del-WA (PP)	WA	(14,603)	-	-	(14,603)	-	-	-	-	-
4074200	Reg Credits-BPA Exch	505204	Regional Bill Intchg Rec/Del-ID (RMP)	IDU	(8,729)	-	-	-	-	-	(8,729)	-	-
4074200 Total					**(74,646)**	**-**	**(51,314)**	**(14,603)**	**-**	**-**	**(8,729)**	**-**	**-**
Grand Total					**46,387**	**5,662**	**11,606**	**2,954**	**9,571**	**20,265**	**2,211**	**1**	**(5,883)**

B5. TAXES OTHER THAN INCOME

PACIFICORP

Taxes Other Than Income (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4081000	TAX OTH INC-U OP I	584960	Taxes Other Non-Income - Credit	SO	(539)	(16)	(151)	(38)	(66)	(240)	(29)	(0)	-
4081000 Total					**(539)**	**(16)**	**(151)**	**(38)**	**(66)**	**(240)**	**(29)**	**(0)**	**-**
4081500	PROPERTY TAXES	579000	PROPERTY TAX	GPS	152,361	4,945	42,554	10,634	18,288	67,794	8,144	4	-
4081500	PROPERTY TAXES	579012	Property Tax Exp - Reg Deferral/Amortz	OR	236	-	236	-	-	-	-	-	-
4081500 Total					**152,597**	**4,945**	**42,790**	**10,634**	**18,288**	**67,794**	**8,144**	**4**	**-**
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	CA	1,986	1,986	-	-	-	-	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	OR	43,348	-	43,348	-	-	-	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	UT	9	-	-	-	-	9	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	WYP	2,514	-	-	-	2,514	-	-	-	-
4081800 Total					**47,857**	**1,986**	**43,348**	**-**	**2,514**	**9**	**-**	**-**	**-**
4081990	MISC TAXES - OTHER	583252	Federal Excise Tax	SO	3,880	118	1,083	272	471	1,727	209	0	-
4081990	MISC TAXES - OTHER	583260	PUBLIC UTILITY TAX	SO	18,676	566	5,212	1,311	2,269	8,313	1,004	1	-
4081990	MISC TAXES - OTHER	583261	OREGON ENERGY RESOURCE SUPPLIER TAX	OR	1,479	-	1,479	-	-	-	-	-	-
4081990	MISC TAXES - OTHER	583263	MONTANA ENERGY TAX	SE	331	4	89	22	47	148	20	0	-
4081990	MISC TAXES - OTHER	583265	WASHINGTON GROSS REVENUE TAX - SERVICE	WA	22	-	-	22	-	-	-	-	-
4081990	MISC TAXES - OTHER	583266	IDAHO KILOWATT HOUR TAX	SE	54	1	15	4	8	24	3	0	-
4081990	MISC TAXES - OTHER	583267	WYOMING ANNUAL CORPORATION FEE (TAX)	WYP	123	-	-	-	123	-	-	-	-
4081990	MISC TAXES - OTHER	583269	MONTANA WHOLESALE ENERGY TAX	SE	236	3	63	16	34	106	14	0	-
4081990	MISC TAXES - OTHER	583273	Wyoming Wind Generation Tax	SG	4,985	69	1,384	366	663	2,222	280	0	-
4081990	MISC TAXES - OTHER	583274	Nevada Commerce Tax	SO	8	0	2	1	1	4	0	0	-
4081990	MISC TAXES - OTHER	584100	GOVERNMENT ROYALTIES	SE	539	7	145	36	77	242	32	0	-
4081990 Total					**30,333**	**768**	**9,471**	**2,049**	**3,694**	**12,786**	**1,563**	**1**	**-**
Grand Total					**230,247**	**7,681**	**95,459**	**12,645**	**24,431**	**80,349**	**9,678**	**5**	**-**

B6. FEDERAL INCOME TAXES

PACIFICORP

Interest Expense & Renewable Energy Tax Credits
Twelve Months Ended - June 2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4091000		310310	Renewable Electricity Production Tax Cre	SG	(228,635)	(3,169)	(63,459)	(16,772)	(30,419)	(101,941)	(12,866)	(9)	-
4091000		310319	Alternative Fuel Vehicle Refueling Prope	SG	(310)	(4)	(86)	(23)	(41)	(138)	(17)	(0)	-
4091000		600600	Fuel Tax Credit	SE	(32)	(0)	(9)	(2)	(5)	(14)	(2)	(0)	-
4091000		900900	Foreign Tax Credit	SO	(54)	(2)	(15)	(4)	(7)	(24)	(3)	(0)	-
4091000 Total					**(229,031)**	**(3,176)**	**(63,569)**	**(16,800)**	**(30,471)**	**(102,118)**	**(12,888)**	**(9)**	**-**
4191000	AFUDC - OTHER	0	AFUDC - EQUITY	SNP	(161,070)	(6,469)	(42,775)	(10,338)	(18,345)	(74,630)	(8,510)	(4)	-
4191000 Total					**(161,070)**	**(6,469)**	**(42,775)**	**(10,338)**	**(18,345)**	**(74,630)**	**(8,510)**	**(4)**	**-**
4270000	INT ON LNG-TRM DBT	585001	INTEREST EXPENSE - LONG-TERM DEBT - FMBS	SNP	680,375	27,327	180,684	43,667	77,490	315,242	35,947	17	-
4270000	INT ON LNG-TRM DBT	585002	INTEREST EXPENSE - LONG-TERM DEBT - MTNS	SNP	6,710	270	1,782	431	764	3,109	355	0	-
4270000	INT ON LNG-TRM DBT	585004	INTEREST EXPENSE - LT DEBT - PCRBS VARIA	SNP	3,860	155	1,025	248	440	1,788	204	0	-
4270000	INT ON LNG-TRM DBT	585005	INTEREST EXPENSE - LT DEBT - PCRB FEES &	SNP	423	17	112	27	48	196	22	0	-
4270000	INT ON LNG-TRM DBT	585006	Interest Expense - LT Debt - JSNs	SNP	17,587	706	4,671	1,129	2,003	8,149	929	0	-
4270000 Total					**708,955**	**28,475**	**188,274**	**45,501**	**80,745**	**328,485**	**37,457**	**17**	**-**
4280000	AMT DBT DISC & EXP	586160	AMORTIZATION - DEBT DISCOUNT	SNP	1,973	79	524	127	225	914	104	0	-
4280000	AMT DBT DISC & EXP	586170	AMORTIZATION - DEBT ISSUANCE EXP	SNP	5,270	212	1,400	338	600	2,442	278	0	-
4280000 Total					**7,244**	**291**	**1,924**	**465**	**825**	**3,356**	**383**	**0**	**-**
4281000	AMORTZN OF LOSS	586190	AMORTIZATION - LOSS ON REQACQUIRED DEB	SNP	282	11	75	18	32	131	15	0	-
4281000 Total					**282**	**11**	**75**	**18**	**32**	**131**	**15**	**0**	**-**
4310000	OTHER INTEREST EXP	0	4310000/0	SNP	48,628	1,953	12,914	3,121	5,538	22,531	2,569	1	-
4310000	OTHER INTEREST EXP	575059	Current state tax interest income	SNP	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
4310000 Total					**48,628**	**1,953**	**12,914**	**3,121**	**5,538**	**22,531**	**2,569**	**1**	**-**
4313000	INT EXP ON REG LIAB	0	INTEREST EXPENSE ON REG LIABILITIES	SNP	122	5	32	8	14	56	6	0	-
4313000 Total					**122**	**5**	**32**	**8**	**14**	**56**	**6**	**0**	**-**
4320000	AFUDC - BORROWED	585800	INTEREST CAPITALIZED (SEE OTH INCOME)	SNP	(111,660)	(4,485)	(29,653)	(7,166)	(12,717)	(51,736)	(5,899)	(3)	-
4320000	AFUDC - BORROWED	585851	Int Exp - AFUDC Calc	SNP	0	0	0	0	0	0	0	0	-
4320000	AFUDC - BORROWED	585860	INTEREST EXPENSE - AFUDC MANUAL ADJ	SNP	4,634	186	1,231	297	528	2,147	245	0	-
4320000 Total					**(107,026)**	**(4,299)**	**(28,422)**	**(6,869)**	**(12,190)**	**(49,589)**	**(5,655)**	**(3)**	**-**
Grand Total					**268,102**	**16,792**	**68,453**	**15,106**	**26,149**	**128,222**	**13,378**	**3**	**-**

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Schedule M (Actuals)
Twelve Months Ending - June 2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
SCHMAP	105127	Book Depr Allocated to Medicare and M&E	SCHMDEXP	143	5	39	10	17	64	8	0	-
SCHMAP	130100	Non - Deductible Expenses	SO	1,833	56	511	129	223	816	99	0	-
SCHMAP	130400	PMINondeductible Exp	SE	6	0	2	0	1	3	0	0	-
SCHMAP	130505	Executive Compensation 162(m)	SO	1,964	60	548	138	239	874	106	0	-
SCHMAP	130750	Nondeductible Fringe Benefits	SO	130	4	36	9	16	58	7	0	-
SCHMAP	130755	Nondeductible Parking Costs	SO	245	7	68	17	30	109	13	0	-
SCHMAP	505505	Income Tax Interest	SO	(2,560)	(78)	(714)	(180)	(311)	(1,139)	(138)	(0)	-
SCHMAP	610106	PMIFuel Tax Cr	SE	32	0	9	2	5	14	2	0	-
SCHMAP	610107	PMI Dividend Gross Up for Foreign Tax Cr	SO	54	2	15	4	7	24	3	0	-
SCHMAP Total				**1,847**	**56**	**514**	**130**	**225**	**823**	**100**	**0**	**-**
SCHMAT	105100	Capitalized Labor Costs	SO	1,525	46	426	107	185	679	82	0	-
SCHMAT	105120	Book Depreciation	SCHMDEXP	1,188,372	39,749	323,787	83,949	145,341	531,741	63,773	33	-
SCHMAT	105121	PMIBook Depreciation	SE	6,970	87	1,870	468	1,000	3,126	420	0	-
SCHMAT	105130	CIAC	CIAC	182,025	14,589	46,559	9,134	14,717	88,743	8,283	-	-
SCHMAT	105140	Highway relocation	SNPD	3,743	300	957	188	303	1,825	170	-	-
SCHMAT	105142	Avoided Costs	SNP	207,194	8,322	55,024	13,298	23,598	96,001	10,947	5	-
SCHMAT	105146	Capitalization of Test Energy	SG	1,423	20	395	104	189	635	80	0	-
SCHMAT	210200	Prepaid Taxes-property taxes	GPS	(2,062)	(67)	(576)	(144)	(248)	(918)	(110)	(0)	-
SCHMAT	220100	Bad Debts Allowance - Cash Basis	BADDEBT	(5,197)	(276)	(2,220)	(762)	(363)	(1,474)	(101)	-	-
SCHMAT	320270	Reg Asset FAS 158 Pension Liab Adj	SO	5,291	160	1,477	371	643	2,355	285	0	-
SCHMAT	320280	Reg Asset FAS 158 Post Retire Liab	SO	(13,715)	(416)	(3,828)	(963)	(1,666)	(6,104)	(737)	(0)	-
SCHMAT	320281	Reg Asset - Post-Retirement Settlement L	SO	87	3	24	6	11	39	5	0	-
SCHMAT	415115	Reg Asset - UT STEP Pilot Programs Balan	OTHER	1,232	-	-	-	-	-	-	-	1,232
SCHMAT	415251	Reg Asset - Low Carbon Energy Standards	OTHER	2,101	-	-	-	-	-	-	-	2,101
SCHMAT	415252	Reg Asset - Distribution System Plan - O	OTHER	2,790	-	-	-	-	-	-	-	2,790
SCHMAT	415261	Reg Asset-UT Wildland Fire Protection	OTHER	6,901	-	-	-	-	-	-	-	6,901
SCHMAT	415262	Reg Asset -Wildfire Mitigation Account -	OTHER	9,222	-	-	-	-	-	-	-	9,222
SCHMAT	415263	Reg Asset - Wildfire Damaged Asset - OR	OR	1,749	-	1,749	-	-	-	-	-	-
SCHMAT	415264	Reg Asset - TB Flats - OR	OTHER	2,919	-	-	-	-	-	-	-	2,919
SCHMAT	415265	Reg Asset - NTO Transfer Deferral	OTHER	(4,212)	-	-	-	-	-	-	-	(4,212)
SCHMAT	415270	Reg Asset - Electric Vehicle Charging In	OTHER	(4,316)	-	-	-	-	-	-	-	(4,316)
SCHMAT	415301	Environmental Costs WA	WA	9	-	-	9	-	-	-	-	-
SCHMAT	415305	Reg Asset - Cedar Springs II - OR	OTHER	108	-	-	-	-	-	-	-	108
SCHMAT	415424	Contra Reg Asset - Deer Creek Abandonmen	SE	349	4	94	23	50	156	21	0	-
SCHMAT	415426	Reg Asset - 2020 GRC - Meters Replaced b	OTHER	3,835	-	-	-	-	-	-	-	3,835
SCHMAT	415430	Reg Asset - CA - Transportation Electri	OTHER	12	-	-	-	-	-	-	-	12
SCHMAT	415702	Reg Asset - Lake Side Liq.	WYP	27	-	-	-	27	-	-	-	-
SCHMAT	415703	Goodnoe Hills Liquidation Damages - WY	WYP	21	-	-	-	21	-	-	-	-
SCHMAT	415728	Contra Reg Asset - Cholla U4 Closure - O	OTHER	221	-	-	-	-	-	-	-	221
SCHMAT	415729	Contra Reg Asset - Cholla U4 Closure - U	UT	(1,079)	-	-	-	-	(1,079)	-	-	-
SCHMAT	415734	Reg Asset - Cholla Unrecovered Plant - C	CA	674	674	-	-	-	-	-	-	-
SCHMAT	415736	Reg Asset - Cholla Unrecovered Plant - W	WYP	3,810	-	-	-	3,810	-	-	-	-
SCHMAT	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	(30)	-	-	-	-	-	-	-	(30)
SCHMAT	415841	Reg Asset - Emergency Service Programs -	OTHER	42	-	-	-	-	-	-	-	42
SCHMAT	415855	CA - January 2010 Storm Costs	OTHER	643	-	-	-	-	-	-	-	643
SCHMAT	415857	ID - Deferred Overburden Costs	OTHER	(360)	-	-	-	-	-	-	-	(360)
SCHMAT	415858	WY - Deferred Overburden Costs	WYP	(972)	-	-	-	(972)	-	-	-	-
SCHMAT	415868	Reg Asset - UT - Solar Incentive Program	OTHER	203	-	-	-	-	-	-	-	203
SCHMAT	415876	Deferred Excess Net PowerCosts - OR	OTHER	45,641	-	-	-	-	-	-	-	45,641
SCHMAT	415881	Deferral of Renewable Energy Credit - UT	OTHER	154	-	-	-	-	-	-	-	154
SCHMAT	415883	Deferral of Renewable Energy Credit - WY	OTHER	627	-	-	-	-	-	-	-	627
SCHMAT	415940	Reg Liability - Steam Decommissioning -	CA	743	743	-	-	-	-	-	-	-
SCHMAT	415941	Reg Liability - Steam Decommissioning -	OR	1,071	-	1,071	-	-	-	-	-	-
SCHMAT	415942	Reg Liability - Steam Decommissioning -	WA	3,570	-	-	3,570	-	-	-	-	-
SCHMAT	425105	Reg Asset - OR Asset Sale Gain Giveback	OTHER	221	-	-	-	-	-	-	-	221
SCHMAT	425360	Hermiston Swap	SG	172	2	48	13	23	77	10	0	-
SCHMAT	425380	Idaho Customer Balancing Account	OTHER	711	-	-	-	-	-	-	-	711
SCHMAT	430100	Customer Service / Weatherization	OTHER	(94,828)	-	-	-	-	-	-	-	(94,828)
SCHMAT	505125	ACCRUED ROYALTIES	SE	65	1	17	4	9	29	4	0	-

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Schedule M (Actuals)
Twelve Months Ending - June 2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
SCHMAT	505600	Sick Leave Vacation & Personal Time	SO	3,119	95	871	219	379	1,388	168	0	-
SCHMAT	505601	Sick Leave Accrual - PMI	SE	0	0	0	0	0	0	0	0	-
SCHMAT	605100	Trojan Decomissioning Costs	TROJD	236	3	65	17	32	105	13	0	-
SCHMAT	605710	Reverse Accrued Final Reclamation	OTHER	(369)	-	-	-	-	-	-	-	(369)
SCHMAT	605715	Trapper Mine Contract Obligation	SE	76	1	21	5	11	34	5	0	-
SCHMAT	610141	WA Rate Refunds	OTHER	1,366	-	-	-	-	-	-	-	1,366
SCHMAT	610145	REG LIAB-DSM	OTHER	4,306	-	-	-	-	-	-	-	4,306
SCHMAT	610150	REG LIABILITY - BRIDGER MINE ACCELERATED	OR	3,727	-	3,727	-	-	-	-	-	-
SCHMAT	610155	Reg Liability - Plant Closure Cost - WA	WA	1,356	-	-	1,356	-	-	-	-	-
SCHMAT	610156	Reg Liability - Plant Closure Cost - CA	CA	634	634	-	-	-	-	-	-	-
SCHMAT	610157	Reg Liability - Plant Closure Cost - OR	OR	673	-	673	-	-	-	-	-	-
SCHMAT	705240	CA Alternative Rate for Energy Program(C	OTHER	(1,592)	-	-	-	-	-	-	-	(1,592)
SCHMAT	705245	REG LIABILITY - OR DIRECT ACCESS 5 YEAR	OTHER	(1,685)	-	-	-	-	-	-	-	(1,685)
SCHMAT	705246	Reg Liability - Pension Settlement - UT	OTHER	4,138	-	-	-	-	-	-	-	4,138
SCHMAT	705263	Reg Liability - Sale of REC's-WA	OTHER	(156)	-	-	-	-	-	-	-	(156)
SCHMAT	705266	Reg Liability - Energy Savings Assistanc	OTHER	(26)	-	-	-	-	-	-	-	(26)
SCHMAT	705267	Reg Liability - WA Decoupling Mechanism	OTHER	(2,950)	-	-	-	-	-	-	-	(2,950)
SCHMAT	705336	Reg Liability - Sale of Renewable Energy	OTHER	1,991	-	-	-	-	-	-	-	1,991
SCHMAT	705344	Reg Liability - Excess Income Tax Deferr	OTHER	(2,727)	-	-	-	-	-	-	-	(2,727)
SCHMAT	705352	Reg Liability - CA Klamath River Dams Re	CA	(1)	(1)	-	-	-	-	-	-	-
SCHMAT	705400	Reg Liability - OR Injuries & Damages Re	OR	(4,709)	-	(4,709)	-	-	-	-	-	-
SCHMAT	705410	Reg Liability - Cholla Decommissioning -	CA	(127)	(127)	-	-	-	-	-	-	-
SCHMAT	705411	Reg Liability - Cholla Decommissioning -	IDU	(969)	-	-	-	-	-	(969)	-	-
SCHMAT	705412	Reg Liability - Cholla Decommissioning -	OR	(4,266)	-	(4,266)	-	-	-	-	-	-
SCHMAT	705413	Reg Liability - Cholla Decommissioning -	UT	(7,213)	-	-	-	-	(7,213)	-	-	-
SCHMAT	705414	Reg Liability - Cholla Decommissioning -	WYP	(1,781)	-	-	-	(1,781)	-	-	-	-
SCHMAT	705420	Reg Liability - CA GHG Allowance Revenue	OTHER	3,494	-	-	-	-	-	-	-	3,494
SCHMAT	705425	Reg Liability - Bridger Mine Accelerated	WA	1,986	-	-	1,986	-	-	-	-	-
SCHMAT	705450	Reg Liability - Property Insurance Reser	CA	(2,249)	(2,249)	-	-	-	-	-	-	-
SCHMAT	705451	Reg Liability - OR Property Insurance Re	OR	(5,750)	-	(5,750)	-	-	-	-	-	-
SCHMAT	705452	Reg Liability - Property Insurance Reser	WA	444	-	-	444	-	-	-	-	-
SCHMAT	705453	Reg Liability - ID Property Insurance Re	IDU	51	-	-	-	-	-	51	-	-
SCHMAT	705455	Reg Liability - WY Property Insurance Re	WYP	280	-	-	-	280	-	-	-	-
SCHMAT	705519	Regulatory Liability - WA Deferred Exces	OTHER	(0)	-	-	-	-	-	-	-	(0)
SCHMAT	715105	MCI FOG Wire Lease	SG	17	0	5	1	2	8	1	0	-
SCHMAT	720300	Pension / Retirement (Accrued / Prepaid)	SO	(71)	(2)	(20)	(5)	(9)	(32)	(4)	(0)	-
SCHMAT	740100	Post Merger Loss-Reacquired Debt	SNP	282	11	75	18	32	131	15	0	-
SCHMAT	910241	PMI Legal Reserve	SE	1,757	22	471	118	252	788	106	0	-
SCHMAT	910242	Joint Owner Receivable in Dispute	SO	2,439	74	681	171	296	1,085	131	0	-
SCHMAT	910245	Contra Receivable from Joint Owners	SO	(52)	(2)	(15)	(4)	(6)	(23)	(3)	(0)	-
SCHMAT	910905	Bridger Coal Company Underground Mine Co	SE	62	1	17	4	9	28	4	0	-
SCHMAT	920110	PMIWY Extraction Tax	SE	(1,828)	(23)	(490)	(123)	(262)	(820)	(110)	(0)	-
SCHMAT Total				**1,553,614**	**62,379**	**418,227**	**113,583**	**185,913**	**711,310**	**82,538**	**38**	**(20,375)**
SCHMDP	1102051	TAX PERCENTAGE DEPLETION - DEDUCTION	SE	664	8	178	45	95	298	40	0	-
SCHMDP	120100	Preferred Dividend - PPL	SNP	79	3	21	5	9	37	4	0	-
SCHMDP	910900	PMIDepletion	SE	2,960	37	794	199	424	1,328	178	0	-
SCHMDP Total				**3,703**	**48**	**993**	**248**	**529**	**1,662**	**222**	**0**	**-**
SCHMDT	105122	Repair Deduction	SG	185,351	2,569	51,445	13,597	24,660	82,642	10,430	8	-
SCHMDT	105125	Tax Depreciation	TAXDEPR	1,445,350	54,787	400,506	95,388	165,249	653,419	75,847	40	113
SCHMDT	105126	PMITax Depreciation	SE	4,118	51	1,105	276	591	1,847	248	0	-
SCHMDT	105137	Capitalized Depreciation	SO	11,730	356	3,274	823	1,425	5,221	631	0	-
SCHMDT	1051411	AFUDC - DEBT	SNP	106,927	4,295	28,396	6,863	12,178	49,543	5,649	3	-
SCHMDT	1051412	AFUDC - Equity	SNP	160,903	6,463	42,730	10,327	18,326	74,552	8,501	4	-
SCHMDT	105143	Basis Intangible Difference	SNP	266	11	71	17	30	123	14	0	-
SCHMDT	105152	Gain/(Loss) on Prop Dispositions	GPS	10,617	345	2,965	741	1,274	4,724	567	0	-
SCHMDT	105175	Removal Cost (net of salvage)	GPS	86,325	2,802	24,110	6,025	10,362	38,411	4,614	2	-
SCHMDT	105470	Book Gain/Loss on Land Sales	GPS	6,054	196	1,691	423	727	2,694	324	0	-
SCHMDT	1102051	Tax Percentage Depletion - Deduction	SE	188	2	50	13	27	84	11	0	-
SCHMDT	205025	PMI - Fuel Cost Adjustment	SE	(1,235)	(15)	(331)	(83)	(177)	(554)	(74)	(0)	-

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Schedule M (Actuals)
Twelve Months Ending - June 2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
SCHMDT	205200	Coal M&S Inventory Write-Off	SNPD	290	23	74	15	23	141	13	-	-
SCHMDT	205411	PMISEC 263A Adjustment	SE	(1,161)	(15)	(311)	(78)	(167)	(521)	(70)	(0)	-
SCHMDT	210100	Prepaid Taxes-OR PUC	OR	641	-	641	-	-	-	-	-	-
SCHMDT	210120	Prepaid Taxes-UT PUC	UT	681	-	-	-	-	681	-	-	-
SCHMDT	210130	Prepaid Taxes-ID PUC	IDU	65	-	-	-	-	-	65	-	-
SCHMDT	210170	Prepaid Lease-Gadsby Gas Turbine	SG	(575)	(8)	(160)	(42)	(76)	(256)	(32)	(0)	-
SCHMDT	210175	Prepaid - FSA O&M - East	SG	1,478	20	410	108	197	659	83	0	-
SCHMDT	210180	OTHER PREPAIDS	SO	2,544	77	710	179	309	1,132	137	0	-
SCHMDT	210185	Prepaid Aircraft Maintenance Costs	SG	37	1	10	3	5	16	2	0	-
SCHMDT	320279	Reg Liability - FAS 158 Post Retirement	SO	(11,176)	(339)	(3,119)	(784)	(1,358)	(4,974)	(601)	(0)	-
SCHMDT	320286	Reg Asset - Pension Settlement - OR	OTHER	(585)	-	-	-	-	-	-	-	(585)
SCHMDT	320288	Reg Asset - Pension Settlement - WY	WYU	(270)	-	-	-	(270)	-	-	-	-
SCHMDT	415100	Reg Asset -WA Equity Advisory Group (CET	OTHER	(198)	-	-	-	-	-	-	-	(198)
SCHMDT	415110	Def Reg Asset-Transmission Srvc Deposit	SG	3,202	44	889	235	426	1,428	180	0	-
SCHMDT	415200	REG ASSET - OR TRANSPORTATION ELECTRIFIC	OTHER	(2,463)	-	-	-	-	-	-	-	(2,463)
SCHMDT	415250	Reg Asset - OR Energy Storage Pilot Prog	OTHER	(393)	-	-	-	-	-	-	-	(393)
SCHMDT	415255	Reg Asset-WY Wind Test Energy Deferral	WYU	(8)	-	-	-	(8)	-	-	-	-
SCHMDT	415260	Reg Asset - Fire Risk Mitigation - CA	OTHER	24,383	-	-	-	-	-	-	-	24,383
SCHMDT	415300	Hazardous Waste Clean-up Costs	SO	9,242	280	2,579	649	1,123	4,114	497	0	-
SCHMDT	415410	Reg Asset - Energy West Mining	SE	(121)	(2)	(32)	(8)	(17)	(54)	(7)	(0)	-
SCHMDT	415411	ContraRA DeerCreekAband CA	CA	2	2	-	-	-	-	-	-	-
SCHMDT	415412	ContraRA DeerCreekAband ID	IDU	477	-	-	-	-	-	477	-	-
SCHMDT	415415	ContraRA DeerCreekAband WA	WA	13	-	-	13	-	-	-	-	-
SCHMDT	415416	ContraRA DeerCreekAband WY	WYU	(1,431)	-	-	-	(1,431)	-	-	-	-
SCHMDT	415431	Reg Asset - WA Transportation Electrific	OTHER	(494)	-	-	-	-	-	-	-	(494)
SCHMDT	415440	Reg Asset - Low Income Bill Discount - O	OTHER	(2,605)	-	-	-	-	-	-	-	(2,605)
SCHMDT	415441	Reg Asset - Utility Community Advisory G	OTHER	(248)	-	-	-	-	-	-	-	(248)
SCHMDT	415445	Reg Asset - Klamath Unrecovered Plant &	SG	(4,598)	(64)	(1,276)	(337)	(612)	(2,050)	(259)	(0)	-
SCHMDT	415446	Reg Asset - Klamath Unrecovered Plant -	OTHER	10	-	-	-	-	-	-	-	10
SCHMDT	415504	Reg Asset - Deferred Insurance Premiums	OTHER	3,606	-	-	-	-	-	-	-	3,606
SCHMDT	415505	Reg Asset - Deferred Insurance Premiums	OTHER	33,831	-	-	-	-	-	-	-	33,831
SCHMDT	415506	Reg Asset - Deferred Insurance Premium -	OTHER	11,895	-	-	-	-	-	-	-	11,895
SCHMDT	415520	Reg Asset - WA Decoupling Mechanism	OTHER	9,637	-	-	-	-	-	-	-	9,637
SCHMDT	415533	Reg Asset - GRC Memo Account - CA	CA	(5,783)	(5,783)	-	-	-	-	-	-	-
SCHMDT	415535	Reg Asset - WBA GRC Deferral - UT	OTHER	5,615	-	-	-	-	-	-	-	5,615
SCHMDT	415655	CA GHG Allowance	OTHER	5,889	-	-	-	-	-	-	-	5,889
SCHMDT	415680	Deferred Intervenor Funding Grants-OR	OTHER	(1,823)	-	-	-	-	-	-	-	(1,823)
SCHMDT	415681	Reg Asset-Defer Intervenor Funding_Gran	OTHER	65	-	-	-	-	-	-	-	65
SCHMDT	415700	Reg Liability BPA balancing accounts-OR	OTHER	(1,527)	-	-	-	-	-	-	-	(1,527)
SCHMDT	415701	CA Deferred Intervenor Funding	OTHER	35	-	-	-	-	-	-	-	35
SCHMDT	415720	Reg Asset - Community Solar - OR	OTHER	791	-	-	-	-	-	-	-	791
SCHMDT	415755	Reg Asset - Major Mtc Exp - Colstrip U4	WA	(194)	-	-	(194)	-	-	-	-	-
SCHMDT	415815	Insurance Reserve	SO	(138,750)	(4,207)	(38,724)	(9,739)	(16,858)	(61,759)	(7,460)	(4)	-
SCHMDT	415833	Reg Asset - Pension Settlement - CA	OTHER	(24)	-	-	-	-	-	-	-	(24)
SCHMDT	415862	Reg Asset - CA Mobile Home Park Conversi	OTHER	(24)	-	-	-	-	-	-	-	(24)
SCHMDT	415863	Reg Asset - UT Subscriber Solar Program	UT	(84)	-	-	-	-	(84)	-	-	-
SCHMDT	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	819	-	-	-	-	-	-	-	819
SCHMDT	415870	CA Def Excess NPC	OTHER	3,033	-	-	-	-	-	-	-	3,033
SCHMDT	415874	Deferred Excess Net Power Costs - WY 08	OTHER	(62,719)	-	-	-	-	-	-	-	(62,719)
SCHMDT	415875	Deferred Excess Net Power Costs - UT	OTHER	(40,797)	-	-	-	-	-	-	-	(40,797)
SCHMDT	415878	REG ASSET - UT LIQUIDATED DAMAGES NAUGHT	UT	(35)	-	-	-	-	(35)	-	-	-
SCHMDT	415879	Reg Asset - WY Liquidation Damages N2	WYP	(6)	-	-	-	(6)	-	-	-	-
SCHMDT	415885	Reg Asset - Noncurrent Reclass - Other	OTHER	58,417	-	-	-	-	-	-	-	58,417
SCHMDT	415892	Deferred Excess Net Power Costs - ID 09	OTHER	(16,303)	-	-	-	-	-	-	-	(16,303)
SCHMDT	415920	Reg Asset - Depreciation Increase - ID	IDU	(3,485)	-	-	-	-	-	(3,485)	-	-
SCHMDT	415921	Reg Asset - Depreciation Increase - UT	UT	(128)	-	-	-	-	(128)	-	-	-
SCHMDT	415922	Reg Asset - Depreciation Increase - WY	WYP	(442)	-	-	-	(442)	-	-	-	-
SCHMDT	415924	Reg Asset - Carbon Unrecovered Plant - U	UT	(16,746)	-	-	-	-	(16,746)	-	-	-
SCHMDT	415933	Reg Liability - Contra - Carbon Decommis	IDU	(2,573)	-	-	-	-	-	(2,573)	-	-

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Schedule M (Actuals)
Twelve Months Ending - June 2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
SCHMDT	415934	Reg Liability - Contra - Carbon Decommis	UT	(17,054)	-	-	-	-	(17,054)	-	-	-
SCHMDT	415935	Reg Liability - Contra - Carbon Decommis	WYP	(5,669)	-	-	-	(5,669)	-	-	-	-
SCHMDT	415936	REG ASSET - CARBON PLANT DECOMMISSIONIN	SG	(212)	(3)	(59)	(16)	(28)	(95)	(12)	(0)	-
SCHMDT	415943	Reg Asset - Covid-19 Bill Assistance Pro	OTHER	(1,436)	-	-	-	-	-	-	-	(1,436)
SCHMDT	415944	Reg Asset - Covid-19 Bill Assistance Pro	OTHER	(2,326)	-	-	-	-	-	-	-	(2,326)
SCHMDT	425100	Deferred Regulatory Expense-IDU	IDU	(5)	-	-	-	-	-	(5)	-	-
SCHMDT	425215	Unearned Joint Use Pole Contact Revenue	SNPD	(252)	(20)	(65)	(13)	(20)	(123)	(11)	-	-
SCHMDT	430110	Reg Asset balance reclass	OTHER	4,306	-	-	-	-	-	-	-	4,306
SCHMDT	430112	Reg Asset - Other - Balance Reclass	OTHER	(2,723)	-	-	-	-	-	-	-	(2,723)
SCHMDT	505510	Vacation Accrual - PMI	SE	(35)	(0)	(9)	(2)	(5)	(16)	(2)	(0)	-
SCHMDT	505520	PMI Bonus Accrual	SE	69	1	19	5	10	31	4	0	-
SCHMDT	605103	ARO/Reg Diff - Trojan - WA	WA	(61)	-	-	(61)	-	-	-	-	-
SCHMDT	610100	PMIDEVT COST AMORT	SE	(298)	(4)	(80)	(20)	(43)	(133)	(18)	(0)	-
SCHMDT	610111	Bridger Coal Company Gain/Loss on Assets	SE	(6)	(0)	(2)	(0)	(1)	(3)	(0)	(0)	-
SCHMDT	610114	PMI EITF Pre Stripping Costs	SE	(2,130)	(27)	(571)	(143)	(305)	(955)	(128)	(0)	-
SCHMDT	610146	OR Reg Asset/Liability Consolidation	OR	36	-	36	-	-	-	-	-	-
SCHMDT	705200	Oregon Gain on Sale of Halsey-OR	OTHER	(521)	-	-	-	-	-	-	-	(521)
SCHMDT	705261	Reg Liability - Sale of Renewable Energy	OTHER	(928)	-	-	-	-	-	-	-	(928)
SCHMDT	705265	Reg Liab - OR Energy Conservation Charge	OTHER	(2,251)	-	-	-	-	-	-	-	(2,251)
SCHMDT	705337	Reg Liability - Sale of Renewable Energy	OTHER	(1,066)	-	-	-	-	-	-	-	(1,066)
SCHMDT	705454	Reg Liability - UT Property Insurance Re	UT	(844)	-	-	-	-	(844)	-	-	-
SCHMDT	705755	Reg Liability - Non current Reclass - Ot	OTHER	(58,417)	-	-	-	-	-	-	-	(58,417)
SCHMDT	715295	Reg Liability - Fly Ash - OR	OTHER	(116)	-	-	-	-	-	-	-	(116)
SCHMDT	715296	Reg Liability - Fly Ash - WA	OTHER	1,360	-	-	-	-	-	-	-	1,360
SCHMDT	720200	Deferred Comp Plan Benefits-PPL	SO	579	18	161	41	70	258	31	0	-
SCHMDT	720500	Severance Accrual	SO	2,771	84	773	194	337	1,233	149	0	-
SCHMDT	720805	FAS 158 - Funded Pension Asset	SO	11,284	342	3,149	792	1,371	5,022	607	0	-
SCHMDT	720815	FAS 158 Post Retirement Liability	SO	1,200	36	335	84	146	534	65	0	-
SCHMDT	910530	Injuries and Damages Reserve	SO	509,038	15,434	142,067	35,728	61,847	226,578	27,369	14	-
SCHMDT Total				**2,309,816**	**77,753**	**663,459**	**161,016**	**273,219**	**1,048,705**	**121,778**	**68**	**(36,183)**
Grand Total				**3,868,981**	**140,237**	**1,083,194**	**274,977**	**459,886**	**1,762,500**	**204,638**	**107**	**(56,557)**

B7. D.I.T. EXPENSE AND I.T.C. ADJUSTMENT

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
DIT-ELEC-DEBIT	105122	Repair Deduction	SG	45,571	632	12,649	3,343	6,063	20,319	2,564	2	-
DIT-ELEC-DEBIT	105125	Tax Depreciation	TAXDEPR	355,362	13,470	98,471	23,453	40,629	160,654	18,648	10	28
DIT-ELEC-DEBIT	105126	282DIT PMIDepreciation-Tax	SE	1,013	13	272	68	145	454	61	0	-
DIT-ELEC-DEBIT	105137	Capitalized Depreciation	SO	2,884	87	805	202	350	1,284	155	0	-
DIT-ELEC-DEBIT	105141	AFUDC Debt	SNP	26,290	1,056	6,982	1,687	2,994	12,181	1,389	1	-
DIT-ELEC-DEBIT	1051411	AFUDC Equity	SNP	39,560	1,589	10,506	2,539	4,506	18,330	2,090	1	-
DIT-ELEC-DEBIT	105143	282Basis Intangible Difference	SNP	65	3	17	4	7	30	3	0	-
DIT-ELEC-DEBIT	105152	Gain / (Loss) on Prop. Disposition	GPS	2,610	85	729	182	313	1,161	140	0	-
DIT-ELEC-DEBIT	105175	Cost of Removal	GPS	21,224	689	5,928	1,481	2,548	9,444	1,134	1	-
DIT-ELEC-DEBIT	105470	282Book Gain/Loss on Land Sales	GPS	1,488	48	416	104	179	662	80	0	-
DIT-ELEC-DEBIT	1102051	Tax Percentage Depletion - Deduction (BI	SE	46	1	12	3	7	21	3	0	-
DIT-ELEC-DEBIT	205025	PMI-Fuel Cost Adjustment	SE	(304)	(4)	(81)	(20)	(44)	(136)	(18)	(0)	-
DIT-ELEC-DEBIT	205200	M&S INVENTORY WRITE-OFF	SNPD	71	6	18	4	6	35	3	-	-
DIT-ELEC-DEBIT	205411	190PMISec263A	SE	(285)	(4)	(77)	(19)	(41)	(128)	(17)	(0)	-
DIT-ELEC-DEBIT	210100	283OR PUC Prepaid Taxes	OR	158	-	158	-	-	-	-	-	-
DIT-ELEC-DEBIT	210120	283UT PUC Prepaid Taxes	UT	167	-	-	-	-	167	-	-	-
DIT-ELEC-DEBIT	210130	283ID PUC Prepaid Taxes	IDU	16	-	-	-	-	-	16	-	-
DIT-ELEC-DEBIT	210170	Prepaid - FSA O&M - West	SG	(141)	(2)	(39)	(10)	(19)	(63)	(8)	(0)	-
DIT-ELEC-DEBIT	210175	Prepaid - FSA O&M - East	SG	363	5	101	27	48	162	20	0	-
DIT-ELEC-DEBIT	210180	283Prepaid Membership Fees-EEI WSCC	SO	625	19	175	44	76	278	34	0	-
DIT-ELEC-DEBIT	210185	Prepaid Aircraft Maintenance Costs	SG	9	0	3	1	1	4	1	0	-
DIT-ELEC-DEBIT	210190	Prepaid Water Rights	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
DIT-ELEC-DEBIT	320279	Reg Liability - FAS 158 Post Retirement	SO	(2,748)	(83)	(767)	(193)	(334)	(1,223)	(148)	(0)	-
DIT-ELEC-DEBIT	320286	Reg Asset - Pension Settlement - OR	OTHER	(144)	-	-	-	-	-	-	-	(144)
DIT-ELEC-DEBIT	320288	Reg Asset - Pension Settlement - WY	WYU	(66)	-	-	-	(66)	-	-	-	-
DIT-ELEC-DEBIT	415100	Reg Asset -WA Equity Advisory Group (CET	OTHER	(49)	-	-	-	-	-	-	-	(49)
DIT-ELEC-DEBIT	415110	190DEF REG ASSET-TRANSM SVC DEPOSIT	SG	787	11	219	58	105	351	44	0	-
DIT-ELEC-DEBIT	415200	REG ASSET - OR TRANSPORTATION ELECTRIFIC	OTHER	(606)	-	-	-	-	-	-	-	(606)
DIT-ELEC-DEBIT	415250	Reg Asset - OR Energy Storage Pilot Prog	OTHER	(97)	-	-	-	-	-	-	-	(97)
DIT-ELEC-DEBIT	415255	Reg Asset-WY Wind Test Energy Deferral	WYU	(2)	-	-	-	(2)	-	-	-	-
DIT-ELEC-DEBIT	415260	Reg Asset - Fire Risk Mitigation - CA	OTHER	5,995	-	-	-	-	-	-	-	5,995
DIT-ELEC-DEBIT	415300	283Hazardous Waste/Environmental Cleanup	SO	2,272	69	634	159	276	1,011	122	0	-
DIT-ELEC-DEBIT	415410	Reg Asset - Energy West Mining	SE	(30)	(0)	(8)	(2)	(4)	(13)	(2)	(0)	-
DIT-ELEC-DEBIT	415411	ContraRA DeerCreekAband CA	CA	0	0	-	-	-	-	-	-	-
DIT-ELEC-DEBIT	415412	ContraRA DeerCreekAband ID	IDU	117	-	-	-	-	-	117	-	-
DIT-ELEC-DEBIT	415415	ContraRA DeerCreekAband WA	WA	3	-	-	3	-	-	-	-	-
DIT-ELEC-DEBIT	415416	ContraRA DeerCreekAband WY	WYU	(352)	-	-	-	(352)	-	-	-	-
DIT-ELEC-DEBIT	415431	Reg Asset - WA Transportation Electrific	OTHER	(121)	-	-	-	-	-	-	-	(121)
DIT-ELEC-DEBIT	415440	Reg Asset - Low Income Bill Discount - O	OTHER	(640)	-	-	-	-	-	-	-	(640)
DIT-ELEC-DEBIT	415441	Reg Asset - Utility Community Advisory G	OTHER	(61)	-	-	-	-	-	-	-	(61)
DIT-ELEC-DEBIT	415445	Reg Asset - Klamath Unrecovered Plant &	SG	(1,131)	(16)	(314)	(83)	(150)	(504)	(64)	(0)	-
DIT-ELEC-DEBIT	415446	Reg Asset - Klamath Unrecovered Plant -	OTHER	3	-	-	-	-	-	-	-	3
DIT-ELEC-DEBIT	415504	Reg Asset - Deferred Insurance Premiums	OTHER	887	-	-	-	-	-	-	-	887
DIT-ELEC-DEBIT	415505	Reg Asset - Deferred Insurance Premiums	OTHER	8,318	-	-	-	-	-	-	-	8,318
DIT-ELEC-DEBIT	415506	Reg Asset - Deferred Insurance Premium -	OTHER	2,924	-	-	-	-	-	-	-	2,924
DIT-ELEC-DEBIT	415520	Reg Asset - WA Decoupling Mechanism	OTHER	2,369	-	-	-	-	-	-	-	2,369
DIT-ELEC-DEBIT	415533	Reg Asset - GRC Memo Account - CA	CA	(1,422)	(1,422)	-	-	-	-	-	-	-
DIT-ELEC-DEBIT	415535	Reg Asset - WBA GRC Deferral - UT	OTHER	1,381	-	-	-	-	-	-	-	1,381
DIT-ELEC-DEBIT	415655	CA GHG Allowance	OTHER	1,448	-	-	-	-	-	-	-	1,448
DIT-ELEC-DEBIT	415680	190Def Intervenor Funding Grants-OR	OTHER	(448)	-	-	-	-	-	-	-	(448)
DIT-ELEC-DEBIT	415681	Reg Asset-Defer Intervenor Funding Gran	OTHER	16	-	-	-	-	-	-	-	16
DIT-ELEC-DEBIT	415700	190Reg Liabs BPA balancing accounts-OR	OTHER	(375)	-	-	-	-	-	-	-	(375)

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
DIT-ELEC-DEBIT	415701	CA Deferred Intervenor Funding	OTHER	9	-	-	-	-	-	-	-	9
DIT-ELEC-DEBIT	415720	Reg Asset - Community Solar - OR	OTHER	194	-	-	-	-	-	-	-	194
DIT-ELEC-DEBIT	415755	Reg Asset - Major Mtc Exp - Colstrip U4	WA	(48)	-	-	(48)	-	-	-	-	-
DIT-ELEC-DEBIT	415815	Insurance Reserve	SO	(34,114)	(1,034)	(9,521)	(2,394)	(4,145)	(15,184)	(1,834)	(1)	-
DIT-ELEC-DEBIT	415833	Reg Asset - Pension Settlement - CA	OTHER	(6)	-	-	-	-	-	-	-	(6)
DIT-ELEC-DEBIT	415862	Reg Asset - CA Mobile Home Park Conversi	OTHER	(6)	-	-	-	-	-	-	-	(6)
DIT-ELEC-DEBIT	415863	Reg Asset - UT Subscriber Solar Program	UT	(21)	-	-	-	-	(21)	-	-	-
DIT-ELEC-DEBIT	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	201	-	-	-	-	-	-	-	201
DIT-ELEC-DEBIT	415870	Deferred Excess Net Power Costs CA	OTHER	746	-	-	-	-	-	-	-	746
DIT-ELEC-DEBIT	415874	Deferred Excess Net Power Costs - WY 09	OTHER	(15,420)	-	-	-	-	-	-	-	(15,420)
DIT-ELEC-DEBIT	415875	Deferred Excess Net Power Costs - UT	OTHER	(10,030)	-	-	-	-	-	-	-	(10,030)
DIT-ELEC-DEBIT	415878	REG ASSET - UT LIQUIDATED DAMAGES NAUGHT	UT	(9)	-	-	-	-	(9)	-	-	-
DIT-ELEC-DEBIT	415879	Reg Asset - WY Liquidation Damages N2	WYP	(1)	-	-	-	(1)	-	-	-	-
DIT-ELEC-DEBIT	415885	Reg Asset - Noncurrent Reclass - Other	OTHER	14,363	-	-	-	-	-	-	-	14,363
DIT-ELEC-DEBIT	415892	Deferred Excess Net Power Costs - ID 09	OTHER	(4,008)	-	-	-	-	-	-	-	(4,008)
DIT-ELEC-DEBIT	415920	Reg Asset - Depreciation Increase - ID	IDU	(857)	-	-	-	-	-	(857)	-	-
DIT-ELEC-DEBIT	415921	Reg Asset - Depreciation Increase - UT	UT	(31)	-	-	-	-	(31)	-	-	-
DIT-ELEC-DEBIT	415922	Reg Asset - Depreciation Increase - WY	WYP	(109)	-	-	-	(109)	-	-	-	-
DIT-ELEC-DEBIT	415924	Reg Asset - Carbon Unrecovered Plant - U	UT	(4,117)	-	-	-	-	(4,117)	-	-	-
DIT-ELEC-DEBIT	415933	Reg Liability - Contra - Carbon Decommis	IDU	(633)	-	-	-	-	-	(633)	-	-
DIT-ELEC-DEBIT	415934	Reg Liability - Contra - Carbon Decommis	UT	(4,193)	-	-	-	-	(4,193)	-	-	-
DIT-ELEC-DEBIT	415935	Reg Liability - Contra - Carbon Decommis	WYP	(1,394)	-	-	-	(1,394)	-	-	-	-
DIT-ELEC-DEBIT	415936	REG ASSET - CARBON PLANT DECOMMISSIONIN	SG	(52)	(1)	(14)	(4)	(7)	(23)	(3)	(0)	-
DIT-ELEC-DEBIT	415943	Reg Asset - Covid-19 Bill Assistance Pro	OTHER	(353)	-	-	-	-	-	-	-	(353)
DIT-ELEC-DEBIT	415944	Reg Asset - Covid-19 Bill Assistance Pro	OTHER	(572)	-	-	-	-	-	-	-	(572)
DIT-ELEC-DEBIT	425100	190Deferred Regulatory Expense-IDU	IDU	(1)	-	-	-	-	-	(1)	-	-
DIT-ELEC-DEBIT	425215	283Unearned Joint Use Pole Contact Revnu	SNPD	(62)	(5)	(16)	(3)	(5)	(30)	(3)	-	-
DIT-ELEC-DEBIT	430110	Reg Asset Balance Reclass	OTHER	1,059	-	-	-	-	-	-	-	1,059
DIT-ELEC-DEBIT	430112	Reg Asset - Other - Balance Reclass	OTHER	(670)	-	-	-	-	-	-	-	(670)
DIT-ELEC-DEBIT	505510	190PMI Vacation/Bonus	SE	(9)	(0)	(2)	(1)	(1)	(4)	(1)	(0)	-
DIT-ELEC-DEBIT	505520	Bonus Accrual - PMI	SE	17	0	5	1	2	8	1	0	-
DIT-ELEC-DEBIT	605103	ARO/Reg Diff - Trojan - WA	WA	(15)	-	-	(15)	-	-	-	-	-
DIT-ELEC-DEBIT	610100	283PMI AMORT DEVELOPMENT	SE	(73)	(1)	(20)	(5)	(10)	(33)	(4)	(0)	-
DIT-ELEC-DEBIT	610111	283PMI SALE OF ASSETS	SE	(1)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	-
DIT-ELEC-DEBIT	610114	PMI EITF Pre stripping Cost	SE	(524)	(7)	(140)	(35)	(75)	(235)	(32)	(0)	-
DIT-ELEC-DEBIT	610146	190OR Reg Asset/Liability Consol	OR	9	-	9	-	-	-	-	-	-
DIT-ELEC-DEBIT	705200	190OR Gain on Sale of Halsey-OR	OTHER	(128)	-	-	-	-	-	-	-	(128)
DIT-ELEC-DEBIT	705261	Reg Liability - Sale of Renewable Energy	OTHER	(228)	-	-	-	-	-	-	-	(228)
DIT-ELEC-DEBIT	705265	Reg Liab - OR Energy Conservation Charge	OTHER	(553)	-	-	-	-	-	-	-	(553)
DIT-ELEC-DEBIT	705337	Reg Liability - Sale of Renewable Energy	OTHER	(262)	-	-	-	-	-	-	-	(262)
DIT-ELEC-DEBIT	705454	Reg Liability - UT Property Insurance Re	UT	(208)	-	-	-	-	(208)	-	-	-
DIT-ELEC-DEBIT	705755	Reg Liability - Non current Reclass - Ot	OTHER	(14,363)	-	-	-	-	-	-	-	(14,363)
DIT-ELEC-DEBIT	715295	Reg Liability - Fly Ash - OR	OTHER	(29)	-	-	-	-	-	-	-	(29)
DIT-ELEC-DEBIT	715296	Reg Liability - Fly Ash - WA	OTHER	334	-	-	-	-	-	-	-	334
DIT-ELEC-DEBIT	720200	190Deferred Compensation Payout	SO	142	4	40	10	17	63	8	0	-
DIT-ELEC-DEBIT	720500	190Severance	SO	681	21	190	48	83	303	37	0	-
DIT-ELEC-DEBIT	720805	FAS 158 - Funded Pension Asset	SO	2,774	84	774	195	337	1,235	149	0	-
DIT-ELEC-DEBIT	720815	FAS 158 Post Retirement Liability	SO	295	9	82	21	36	131	16	0	-
DIT-ELEC-DEBIT	910530	190Injuries & Damages	SO	125,155	3,795	34,929	8,784	15,206	55,708	6,729	4	-
DIT-ELEC-DEBIT Total				**567,905**	**19,117**	**163,122**	**39,588**	**67,175**	**257,841**	**29,941**	**17**	**(8,896)**
DIT-ELEC-FED-CR	105100	190CAPITALIZED LABOR COSTS	SO	(375)	(11)	(105)	(26)	(46)	(167)	(20)	(0)	-
DIT-ELEC-FED-CR	1051151	Depreciation Flow-Through - CA	CA	(533)	(533)	-	-	-	-	-	-	-

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Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
DIT-ELEC-FED-CR	10511510	Def In Tax Exp~Effects Ratemaking-Assets	SG	(35,334)	(490)	(9,807)	(2,592)	(4,701)	(15,754)	(1,988)	(1)	-
DIT-ELEC-FED-CR	10511511	Def In Tax Exp~Effects Ratemaking-AssetS	SG	1,456	20	404	107	194	649	82	0	-
DIT-ELEC-FED-CR	10511512	Def In Tax Exp~Effects Ratemaking-AssetS	SG	204	3	57	15	27	91	11	0	-
DIT-ELEC-FED-CR	10511513	Def In Tax Exp~Effects Ratemaking-Assets	SO	(2,589)	(78)	(722)	(182)	(315)	(1,152)	(139)	(0)	-
DIT-ELEC-FED-CR	1051153	Depreciation Flow-Through - ID	IDU	17	-	-	-	-	-	17	-	-
DIT-ELEC-FED-CR	1051154	Depreciation Flow-Through - OR	OR	(2,497)	-	(2,497)	-	-	-	-	-	-
DIT-ELEC-FED-CR	1051155	Depreciation Flow-Through - OTHER	OTHER	(14)	-	-	-	-	-	-	-	(14)
DIT-ELEC-FED-CR	1051156	Depreciation Flow-Through - UT	UT	(1,972)	-	-	-	-	(1,972)	-	-	-
DIT-ELEC-FED-CR	1051157	Depreciation Flow-Through - WA	WA	38	-	-	38	-	-	-	-	-
DIT-ELEC-FED-CR	1051158	Depreciation Flow-Through - WYP	WYP	310	-	-	-	310	-	-	-	-
DIT-ELEC-FED-CR	1051171	Protected PP&E EDIT - PMI - CA - Fed Onl	CA	(4)	(4)	-	-	-	-	-	-	-
DIT-ELEC-FED-CR	1051172	Protected PP&E EDIT - PMI - UFERC - Fed	FERC	(0)	-	-	-	-	-	-	(0)	-
DIT-ELEC-FED-CR	1051173	Protected PP&E EDIT - PMI - ID - Fed Onl	IDU	(17)	-	-	-	-	-	(17)	-	-
DIT-ELEC-FED-CR	1051174	Protected PP&E EDIT - PMI - OR - Fed Onl	OR	(67)	-	(67)	-	-	-	-	-	-
DIT-ELEC-FED-CR	1051175	Protected PP&E EDIT - PMI - UT - Fed Onl	UT	(114)	-	-	-	-	(114)	-	-	-
DIT-ELEC-FED-CR	1051176	Protected PP&E EDIT - PMI - WA - Fed Onl	WA	(61)	-	-	(61)	-	-	-	-	-
DIT-ELEC-FED-CR	1051177	Protected PP&E EDIT - PMI - WYP - Fed On	WYP	(45)	-	-	-	(45)	-	-	-	-
DIT-ELEC-FED-CR	105120	Book Depreciation	SCHMDEXP	(292,180)	(9,773)	(79,608)	(20,640)	(35,734)	(130,737)	(15,680)	(8)	-
DIT-ELEC-FED-CR	105121	282DIT PMIDepreciation-Book	SE	(1,714)	(21)	(460)	(115)	(246)	(769)	(103)	(0)	-
DIT-ELEC-FED-CR	105130	CIAC	CIAC	(44,754)	(3,587)	(11,447)	(2,246)	(3,618)	(21,819)	(2,037)	-	-
DIT-ELEC-FED-CR	105140	Highway Relocation	SNPD	(920)	(74)	(235)	(46)	(74)	(449)	(42)	-	-
DIT-ELEC-FED-CR	105142	Avoided Costs	SNP	(50,942)	(2,046)	(13,528)	(3,270)	(5,802)	(23,603)	(2,691)	(1)	-
DIT-ELEC-FED-CR	105146	Capitalization of Test Energy	SG	(350)	(5)	(97)	(26)	(47)	(156)	(20)	(0)	-
DIT-ELEC-FED-CR	105271	Def In Tax Exp - Other Property Flowthro	CA	(409)	(409)	-	-	-	-	-	-	-
DIT-ELEC-FED-CR	105272	Def In Tax Exp - Other Property Flowthro	IDU	(234)	-	-	-	-	-	(234)	-	-
DIT-ELEC-FED-CR	105273	Def In Tax Exp - Other Property Flowthro	OR	924	-	924	-	-	-	-	-	-
DIT-ELEC-FED-CR	105274	Def In Tax Exp - Other Property Flowthro	UT	2,337	-	-	-	-	2,337	-	-	-
DIT-ELEC-FED-CR	105275	Def In Tax Exp - Other Property Flowthro	WA	(59)	-	-	(59)	-	-	-	-	-
DIT-ELEC-FED-CR	105276	Def In Tax Exp - Other Property Flowthro	WYP	(1,371)	-	-	-	(1,371)	-	-	-	-
DIT-ELEC-FED-CR	210200	283Prepaid Taxes-Property Taxes	GPS	507	16	142	35	61	226	27	0	-
DIT-ELEC-FED-CR	220100	190Bad Debt Allowance	BADDEBT	1,278	68	546	187	89	362	25	-	-
DIT-ELEC-FED-CR	320270	Reg Asset FAS 158 Pension Liab	SO	(1,301)	(39)	(363)	(91)	(158)	(579)	(70)	(0)	-
DIT-ELEC-FED-CR	320280	Reg Asset FAS 158 Post Retire Liab	SO	3,372	102	941	237	410	1,501	181	0	-
DIT-ELEC-FED-CR	320281	Reg Asset - Post-Retirement Settlement L	SO	(21)	(1)	(6)	(1)	(3)	(10)	(1)	(0)	-
DIT-ELEC-FED-CR	415115	Reg Asset - UT STEP Pilot Programs Balan	OTHER	(303)	-	-	-	-	-	-	-	(303)
DIT-ELEC-FED-CR	415251	Reg Asset - Low Carbon Energy Standards	OTHER	(516)	-	-	-	-	-	-	-	(516)
DIT-ELEC-FED-CR	415252	Reg Asset - Distribution System Plan - O	OTHER	(686)	-	-	-	-	-	-	-	(686)
DIT-ELEC-FED-CR	415261	Reg Asset-UT Wildland Fire Protection	OTHER	(1,697)	-	-	-	-	-	-	-	(1,697)
DIT-ELEC-FED-CR	415262	Reg Asset -Wildfire Mitigation Account -	OTHER	(2,267)	-	-	-	-	-	-	-	(2,267)
DIT-ELEC-FED-CR	415263	Reg Asset - Wildfire Damaged Asset - OR	OR	(430)	-	(430)	-	-	-	-	-	-
DIT-ELEC-FED-CR	415264	Reg Asset - TB Flats - OR	OTHER	(718)	-	-	-	-	-	-	-	(718)
DIT-ELEC-FED-CR	415265	Reg Asset - NTO Transfer Deferral	OTHER	1,036	-	-	-	-	-	-	-	1,036
DIT-ELEC-FED-CR	415270	Reg Asset - Electric Vehicle Charging In	OTHER	1,061	-	-	-	-	-	-	-	1,061
DIT-ELEC-FED-CR	415301	190Hazardous Waste/Environmental-WA	WA	(2)	-	-	(2)	-	-	-	-	-
DIT-ELEC-FED-CR	415305	Reg Asset - Cedar Springs II - OR	OTHER	(27)	-	-	-	-	-	-	-	(27)
DIT-ELEC-FED-CR	415424	Contra Reg Asset - Deer Creek Abandonmen	SE	(86)	(1)	(23)	(6)	(12)	(38)	(5)	(0)	-
DIT-ELEC-FED-CR	415426	Reg Asset - 2020 GRC - Meters Replaced b	OTHER	(943)	-	-	-	-	-	-	-	(943)
DIT-ELEC-FED-CR	415430	Reg Asset - CA - Transportation Electri	OTHER	(3)	-	-	-	-	-	-	-	(3)
DIT-ELEC-FED-CR	415645	RA - OR OCAT Expense Deferral	OTHER	2	-	-	-	-	-	-	-	2
DIT-ELEC-FED-CR	415702	REG ASSET - LAKE SIDE LIQ - WY	WYP	(7)	-	-	-	(7)	-	-	-	-
DIT-ELEC-FED-CR	415703	Goodnoe Hills Liquidation Damages - WY	WYP	(5)	-	-	-	(5)	-	-	-	-
DIT-ELEC-FED-CR	415728	Contra Reg Asset - Cholla U4 Closure - O	OTHER	(54)	-	-	-	-	-	-	-	(54)

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Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
DIT-ELEC-FED-CR	415729	Contra Reg Asset - Cholla U4 Closure - U	UT	265	-	-	-	-	265	-	-	-
DIT-ELEC-FED-CR	415734	Reg Asset - Cholla Unrecovered Plant - C	CA	(166)	(166)	-	-	-	-	-	-	-
DIT-ELEC-FED-CR	415736	Reg Asset - Cholla Unrecovered Plant - W	WYP	(937)	-	-	-	(937)	-	-	-	-
DIT-ELEC-FED-CR	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	7	-	-	-	-	-	-	-	7
DIT-ELEC-FED-CR	415841	Reg Asset - Emergency Service Programs -	OTHER	(10)	-	-	-	-	-	-	-	(10)
DIT-ELEC-FED-CR	415855	CA - January 2010 Storm Costs	OTHER	(158)	-	-	-	-	-	-	-	(158)
DIT-ELEC-FED-CR	415857	ID - Deferred Overburden Costs	OTHER	89	-	-	-	-	-	-	-	89
DIT-ELEC-FED-CR	415858	WY - Deferred Overburden Costs	WYP	239	-	-	-	239	-	-	-	-
DIT-ELEC-FED-CR	415868	Reg Asset - UT - Solar Incentive Program	OTHER	(50)	-	-	-	-	-	-	-	(50)
DIT-ELEC-FED-CR	415876	Deferred Excess Net PowerCosts - OR	OTHER	(11,221)	-	-	-	-	-	-	-	(11,221)
DIT-ELEC-FED-CR	415881	Deferral of Renewable Energy Credit - UT	OTHER	(38)	-	-	-	-	-	-	-	(38)
DIT-ELEC-FED-CR	415883	Deferral of Renewable Energy Credit - WY	OTHER	(154)	-	-	-	-	-	-	-	(154)
DIT-ELEC-FED-CR	415940	Reg Liability - Steam Decommissioning -	CA	(183)	(183)	-	-	-	-	-	-	-
DIT-ELEC-FED-CR	415941	Reg Liability - Steam Decommissioning -	OR	(263)	-	(263)	-	-	-	-	-	-
DIT-ELEC-FED-CR	415942	Reg Liability - Steam Decommissioning -	WA	(878)	-	-	(878)	-	-	-	-	-
DIT-ELEC-FED-CR	425105	Reg Asset - OR Asset Sale Gain Giveback	OTHER	(54)	-	-	-	-	-	-	-	(54)
DIT-ELEC-FED-CR	425360	190Hermiston Swap	SG	(42)	(1)	(12)	(3)	(6)	(19)	(2)	(0)	-
DIT-ELEC-FED-CR	425380	190Idaho Customer Bal Acct	OTHER	(175)	-	-	-	-	-	-	-	(175)
DIT-ELEC-FED-CR	430100	283Weatherization	OTHER	23,315	-	-	-	-	-	-	-	23,315
DIT-ELEC-FED-CR	505125	190Accrued Royalties	SE	(16)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
DIT-ELEC-FED-CR	505600	190Vacation Sickleave & PT Accrual	SO	(767)	(23)	(214)	(54)	(93)	(341)	(41)	(0)	-
DIT-ELEC-FED-CR	505601	Sick Leave Accrual - PMI	SE	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
DIT-ELEC-FED-CR	605100	283TROJAN DECOMMISSIONING AMORT	TROJD	(58)	(1)	(16)	(4)	(8)	(26)	(3)	(0)	-
DIT-ELEC-FED-CR	605710	REVERSE ACCRUED FINAL RECLAMATION	OTHER	91	-	-	-	-	-	-	-	91
DIT-ELEC-FED-CR	605715	Trapper Mine Contract Obligation	SE	(19)	(0)	(5)	(1)	(3)	(8)	(1)	(0)	-
DIT-ELEC-FED-CR	610141	190WA Rate Refunds	OTHER	(336)	-	-	-	-	-	-	-	(336)
DIT-ELEC-FED-CR	610145	190REG LIAB_DSM	OTHER	(1,059)	-	-	-	-	-	-	-	(1,059)
DIT-ELEC-FED-CR	610150	REG LIABILITY - BRIDGER MINE ACCELERATED	OR	(916)	-	(916)	-	-	-	-	-	-
DIT-ELEC-FED-CR	610155	Reg Liability - Plant Closure Cost - WA	WA	(333)	-	-	(333)	-	-	-	-	-
DIT-ELEC-FED-CR	610156	Reg Liability - Plant Closure Cost - CA	CA	(156)	(156)	-	-	-	-	-	-	-
DIT-ELEC-FED-CR	610157	Reg Liability - Plant Closure Cost - OR	OR	(166)	-	(166)	-	-	-	-	-	-
DIT-ELEC-FED-CR	705240	283CA Alternative Rate for Energy Progra	OTHER	391	-	-	-	-	-	-	-	391
DIT-ELEC-FED-CR	705245	REG LIABILITY - OR DIRECT ACCESS 5 YEAR	OTHER	414	-	-	-	-	-	-	-	414
DIT-ELEC-FED-CR	705246	Reg Liability - Pension Settlement - UT	OTHER	(1,017)	-	-	-	-	-	-	-	(1,017)
DIT-ELEC-FED-CR	705263	Reg Liability - Sale of REC's-WA	OTHER	38	-	-	-	-	-	-	-	38
DIT-ELEC-FED-CR	705266	Reg Liability - Energy Savings Assistanc	OTHER	6	-	-	-	-	-	-	-	6
DIT-ELEC-FED-CR	705267	Reg Liability - WA Decoupling Mechanism	OTHER	725	-	-	-	-	-	-	-	725
DIT-ELEC-FED-CR	705284	Non-Property EDIT - WA	WA	(219)	-	-	(219)	-	-	-	-	-
DIT-ELEC-FED-CR	705287	Protected PP&E EDIT - CA - Fed Only	CA	(1,181)	(1,181)	-	-	-	-	-	-	-
DIT-ELEC-FED-CR	705288	Protected PP&E EDIT - ID - Fed Only	IDU	(3,045)	-	-	-	-	-	(3,045)	-	-
DIT-ELEC-FED-CR	705289	Protected PP&E EDIT - OR - Fed Only	OR	(13,342)	-	(13,342)	-	-	-	-	-	-
DIT-ELEC-FED-CR	705290	Protected PP&E EDIT - WA - Fed Only	WA	(2,142)	-	-	(2,142)	-	-	-	-	-
DIT-ELEC-FED-CR	705291	Protected PP&E EDIT - WYP - Fed Only	WYP	(8,065)	-	-	-	(8,065)	-	-	-	-
DIT-ELEC-FED-CR	705292	Protected PP&E EDIT - UT - Fed Only	UT	(22,891)	-	-	-	-	(22,891)	-	-	-
DIT-ELEC-FED-CR	705296	Non-Protected PP&E EDIT - WA	WA	(4,322)	-	-	(4,322)	-	-	-	-	-
DIT-ELEC-FED-CR	705297	Non-Protected PP&E EDIT - WY Buydown - C	WYP	(3,875)	-	-	-	(3,875)	-	-	-	-
DIT-ELEC-FED-CR	705336	Reg Liability - Sale of Renewable Energy	OTHER	(489)	-	-	-	-	-	-	-	(489)
DIT-ELEC-FED-CR	705344	Reg Liability - Excess Income Tax Deferr	OTHER	671	-	-	-	-	-	-	-	671
DIT-ELEC-FED-CR	705350	Deferral of Protected PP&E ARAM - WA	WA	(2,633)	-	-	(2,633)	-	-	-	-	-
DIT-ELEC-FED-CR	705351	Deferral of Protected PP&E ARAM - WY	WYU	(3,806)	-	-	-	(3,806)	-	-	-	-
DIT-ELEC-FED-CR	705352	Reg Liability - CA Klamath River Dams Re	CA	0	0	-	-	-	-	-	-	-
DIT-ELEC-FED-CR	705400	Reg Liability - OR Injuries & Damages Re	OR	1,158	-	1,158	-	-	-	-	-	-

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Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
DIT-ELEC-FED-CR	705410	Reg Liability - Cholla Decommissioning -	CA	31	31	-	-	-	-	-	-	-
DIT-ELEC-FED-CR	705411	Reg Liability - Cholla Decommissioning -	IDU	238	-	-	-	-	-	238	-	-
DIT-ELEC-FED-CR	705412	Reg Liability - Cholla Decommissioning -	OR	1,049	-	1,049	-	-	-	-	-	-
DIT-ELEC-FED-CR	705413	Reg Liability - Cholla Decommissioning -	UT	1,773	-	-	-	-	1,773	-	-	-
DIT-ELEC-FED-CR	705414	Reg Liability - Cholla Decommissioning -	WYP	438	-	-	-	438	-	-	-	-
DIT-ELEC-FED-CR	705420	Reg Liability - CA GHG Allowance Revenue	OTHER	(859)	-	-	-	-	-	-	-	(859)
DIT-ELEC-FED-CR	705425	Reg Liability - Bridger Mine Accelerated	WA	(488)	-	-	(488)	-	-	-	-	-
DIT-ELEC-FED-CR	705450	Reg Liability - Property Insurance Reser	CA	553	553	-	-	-	-	-	-	-
DIT-ELEC-FED-CR	705451	Reg Liability - OR Property Insurance Re	OR	1,414	-	1,414	-	-	-	-	-	-
DIT-ELEC-FED-CR	705452	Reg Liability - Property Insurance Reser	WA	(109)	-	-	(109)	-	-	-	-	-
DIT-ELEC-FED-CR	705453	Reg Liability - ID Property Insurance Re	IDU	(13)	-	-	-	-	-	(13)	-	-
DIT-ELEC-FED-CR	705455	Reg Liability - WY Property Insurance Re	WYP	(69)	-	-	-	(69)	-	-	-	-
DIT-ELEC-FED-CR	715105	MCI FOG Wire Lease	SG	(4)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	-
DIT-ELEC-FED-CR	720300	190Pension/Retirement (Accrued/Prepaid)	SO	18	1	5	1	2	8	1	0	-
DIT-ELEC-FED-CR	740100	283Post Merger Debt Loss	SNP	(69)	(3)	(18)	(4)	(8)	(32)	(4)	(0)	-
DIT-ELEC-FED-CR	910241	PMI Legal Reserve	SE	(432)	(5)	(116)	(29)	(62)	(194)	(26)	(0)	-
DIT-ELEC-FED-CR	910242	Joint Owner Receivable in Dispute	SO	(600)	(18)	(167)	(42)	(73)	(267)	(32)	(0)	-
DIT-ELEC-FED-CR	910245	Contra Receivable from Joint Owners	SO	13	0	4	1	2	6	1	0	-
DIT-ELEC-FED-CR	910905	283PMI BCC Underground Mine Cost Deplet	SE	(15)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
DIT-ELEC-FED-CR	920110	190PMIWYExtractionTax	SE	449	6	121	30	64	202	27	0	-
DIT-ELEC-FED-CR	999998	Deferred Income Tax Expense ~ Solar ITC	SG	24	0	7	2	3	11	1	0	-
DIT-ELEC-FED-CR Total				**(487,511)**	**(18,010)**	**(127,871)**	**(39,975)**	**(67,354)**	**(213,682)**	**(25,606)**	**(11)**	**4,998**
Grand Total				**80,394**	**1,107**	**35,251**	**(386)**	**(179)**	**44,159**	**4,335**	**6**	**(3,898)**

Investment Tax Credit Amortization (Actuals)
Sum of Range: 07/2024 - 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account N	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4114000	DEF ITC-EL-FED-CR	0	DEF ITC CREDIT FED	DGU	(363)	-	-	-	(13)	(312)	(39)	(0)	-
4114000 Total					**(363)**	**-**	**-**	**-**	**(13)**	**(312)**	**(39)**	**(0)**	**-**
Grand Total					**(363)**	**-**	**-**	**-**	**(13)**	**(312)**	**(39)**	**(0)**	**-**

B8. PLANT IN SERVICE

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Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	IDU	1,000	-	-	-	-	-	1,000	-	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG	24,555	340	6,815	1,801	3,267	10,948	1,382	1	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG-P	103,455	1,434	28,715	7,589	13,764	46,127	5,822	4	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG-U	10,502	146	2,915	770	1,397	4,682	591	0	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	OR	531	-	531	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	SG	57,321	795	15,910	4,205	7,626	25,558	3,226	2	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	UT	3,157	-	-	-	-	3,157	-	-	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	WYP	4,229	-	-	-	4,229	-	-	-	-
1010000	ELEC PLANT IN SERV	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	207	3	57	15	28	92	12	0	-
1010000	ELEC PLANT IN SERV	3032740	GADSBY INTANGIBLE ASSETS	SG	51	1	14	4	7	23	3	0	-
1010000	ELEC PLANT IN SERV	3032760	SWIFT 2 IMPROVEMENTS	SG	23,200	322	6,439	1,702	3,087	10,344	1,306	1	-
1010000	ELEC PLANT IN SERV	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	652	9	181	48	87	291	37	0	-
1010000	ELEC PLANT IN SERV	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	117	2	33	9	16	52	7	0	-
1010000	ELEC PLANT IN SERV	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSET	SG	8,774	122	2,435	644	1,167	3,912	494	0	-
1010000	ELEC PLANT IN SERV	3032910	WYOMING VHF (VPC) SPECTRUM	WYP	1,039	-	-	-	1,039	-	-	-	-
1010000	ELEC PLANT IN SERV	3032920	IDAHO VHF (VPC) SPECTRUM	IDU	3,357	-	-	-	-	-	3,357	-	-
1010000	ELEC PLANT IN SERV	3032930	UTAH VHF (VPC) SPECTRUM	UT	4,287	-	-	-	-	4,287	-	-	-
1010000	ELEC PLANT IN SERV	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	84,519	1,172	23,459	6,200	11,245	37,684	4,756	3	-
1010000	ELEC PLANT IN SERV	3033330	OR VHF (VPC) SPECTRUM	OR	4,071	-	4,071	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3033340	WA VHF (VPC) SPECTRUM	WA	2,021	-	-	2,021	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3033350	CA VHF (VPC) SPECTRUM	CA	472	472	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3033380	GAS PLANT INTANGIBLES	SG	1,601	22	444	117	213	714	90	0	-
1010000	ELEC PLANT IN SERV	3035320	HYDRO PLANT INTANGIBLES	SG	1,687	23	468	124	224	752	95	0	-
1010000	ELEC PLANT IN SERV	3100000	LAND & LAND RIGHTS	SG	1,306	18	363	96	174	582	74	0	-
1010000	ELEC PLANT IN SERV	3101000	LAND OWNED IN FEE	SG	12,767	177	3,543	937	1,699	5,692	718	1	-
1010000	ELEC PLANT IN SERV	3102000	LAND RIGHTS	SG	807	11	224	59	107	360	45	0	-
1010000	ELEC PLANT IN SERV	3103000	WATER RIGHTS	SG	35,638	494	9,892	2,614	4,742	15,890	2,005	1	-
1010000	ELEC PLANT IN SERV	3110000	STRUCTURES AND IMPROVEMENTS	SG	1,049,095	14,543	291,182	76,957	139,578	467,757	59,034	43	-
1010000	ELEC PLANT IN SERV	3120000	BOILER PLANT EQUIPMENT	SG	4,407,779	61,102	1,223,404	323,337	586,438	1,965,285	248,034	179	-
1010000	ELEC PLANT IN SERV	3140000	TURBOGENERATOR UNITS	SG	965,486	13,384	267,976	70,824	128,454	430,479	54,330	39	-
1010000	ELEC PLANT IN SERV	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	422,019	5,850	117,134	30,958	56,148	188,164	23,748	17	-
1010000	ELEC PLANT IN SERV	3151000	COMPUTER HARDWARE - STEAM	SG	275	4	76	20	37	123	15	0	-
1010000	ELEC PLANT IN SERV	3152000	COMPUTER SOFTWARE (MISC) - STEAM	SG	55	1	15	4	7	24	3	0	-
1010000	ELEC PLANT IN SERV	3153000	COMMUNICATION EQUIPMENT - STEAM	SG	18,541	257	5,146	1,360	2,467	8,267	1,043	1	-
1010000	ELEC PLANT IN SERV	3153005	COMM EQUIP - MOBILE RADIOS - STEAM	SG	214	3	59	16	28	95	12	0	-
1010000	ELEC PLANT IN SERV	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	49	1	14	4	7	22	3	0	-
1010000	ELEC PLANT IN SERV	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	32,916	456	9,136	2,415	4,379	14,676	1,852	1	-
1010000	ELEC PLANT IN SERV	3300000	LAND AND LAND RIGHTS	SG-U	172	2	48	13	23	77	10	0	-
1010000	ELEC PLANT IN SERV	3301000	LAND OWNED IN FEE	SG-P	23,056	320	6,399	1,691	3,067	10,280	1,297	1	-
1010000	ELEC PLANT IN SERV	3301000	LAND OWNED IN FEE	SG-U	5,777	80	1,603	424	769	2,576	325	0	-
1010000	ELEC PLANT IN SERV	3302000	LAND RIGHTS	SG-P	7,356	102	2,042	540	979	3,280	414	0	-
1010000	ELEC PLANT IN SERV	3302000	LAND RIGHTS	SG-U	381	5	106	28	51	170	21	0	-
1010000	ELEC PLANT IN SERV	3303000	WATER RIGHTS	SG-P	21	0	6	2	3	9	1	0	-
1010000	ELEC PLANT IN SERV	3303000	WATER RIGHTS	SG-U	140	2	39	10	19	62	8	0	-
1010000	ELEC PLANT IN SERV	3304000	FLOOD RIGHTS	SG-P	171	2	47	13	23	76	10	0	-
1010000	ELEC PLANT IN SERV	3304000	FLOOD RIGHTS	SG-U	129	2	36	9	17	57	7	0	-
1010000	ELEC PLANT IN SERV	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	310	4	86	23	41	138	17	0	-
1010000	ELEC PLANT IN SERV	3310000	STRUCTURES AND IMPROVE	SG-P	3	0	1	0	0	1	0	0	-
1010000	ELEC PLANT IN SERV	3310000	STRUCTURES AND IMPROVE	SG-U	9,326	129	2,588	684	1,241	4,158	525	0	-
1010000	ELEC PLANT IN SERV	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	70,623	979	19,602	5,181	9,396	31,488	3,974	3	-
1010000	ELEC PLANT IN SERV	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	11,540	160	3,203	847	1,535	5,145	649	0	-
1010000	ELEC PLANT IN SERV	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	189,541	2,627	52,608	13,904	25,218	84,510	10,666	8	-
1010000	ELEC PLANT IN SERV	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	364	5	101	27	48	162	20	0	-
1010000	ELEC PLANT IN SERV	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	26,794	371	7,437	1,965	3,565	11,946	1,508	1	-
1010000	ELEC PLANT IN SERV	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	2,056	29	571	151	274	917	116	0	-
1010000	ELEC PLANT IN SERV	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	14,768	205	4,099	1,083	1,965	6,585	831	1	-
1010000	ELEC PLANT IN SERV	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	10,261	142	2,848	753	1,365	4,575	577	0	-
1010000	ELEC PLANT IN SERV	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	31,228	433	8,668	2,291	4,155	13,924	1,757	1	-
1010000	ELEC PLANT IN SERV	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	395,572	5,484	109,793	29,018	52,629	176,373	22,260	16	-
1010000	ELEC PLANT IN SERV	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	76,255	1,057	21,165	5,594	10,145	34,000	4,291	3	-

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	IDU	1,000	-	-	-	-	-	1,000	-	-
1010000	ELEC PLANT IN SERV	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	18,827	261	5,225	1,381	2,505	8,394	1,059	1	-
1010000	ELEC PLANT IN SERV	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	411	6	114	30	55	183	23	0	-
1010000	ELEC PLANT IN SERV	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	188	3	52	14	25	84	11	0	-
1010000	ELEC PLANT IN SERV	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	63	1	18	5	8	28	4	0	-
1010000	ELEC PLANT IN SERV	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	81,146	1,125	22,523	5,953	10,796	36,180	4,566	3	-
1010000	ELEC PLANT IN SERV	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	51,285	711	14,234	3,762	6,823	22,866	2,886	2	-
1010000	ELEC PLANT IN SERV	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	56,569	784	15,701	4,150	7,526	25,222	3,183	2	-
1010000	ELEC PLANT IN SERV	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	14,653	203	4,067	1,075	1,950	6,533	825	1	-
1010000	ELEC PLANT IN SERV	3341000	COMPUTER HARDWARE - HYDRO	SG	123	2	34	9	16	55	7	0	-
1010000	ELEC PLANT IN SERV	3342000	COMPUTER SOFTWARE (MISC) - HYDRO	SG	23	0	6	2	3	10	1	0	-
1010000	ELEC PLANT IN SERV	3343000	COMMUNICATION EQUIPMENT - HYDRO	SG	12,838	178	3,563	942	1,708	5,724	722	1	-
1010000	ELEC PLANT IN SERV	3343005	COMM EQUIP - MOBILE RADIOS - HYDRO	SG	64	1	18	5	8	28	4	0	-
1010000	ELEC PLANT IN SERV	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	1,609	22	447	118	214	718	91	0	-
1010000	ELEC PLANT IN SERV	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	64	1	18	5	8	28	4	0	-
1010000	ELEC PLANT IN SERV	3350000	MISC POWER PLANT EQUIP	SG-U	220	3	61	16	29	98	12	0	-
1010000	ELEC PLANT IN SERV	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	3,231	45	897	237	430	1,440	182	0	-
1010000	ELEC PLANT IN SERV	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	23,403	324	6,496	1,717	3,114	10,435	1,317	1	-
1010000	ELEC PLANT IN SERV	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	4,492	62	1,247	330	598	2,003	253	0	-
1010000	ELEC PLANT IN SERV	3380000	LAND - SOLAR PRODUCTION	OR	75	-	75	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3380002	STRUCTURES AND IMPROVEMENTS - SOLAR	OR	4	-	4	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3380002	STRUCTURES AND IMPROVEMENTS - SOLAR	UT	69	-	-	-	-	69	-	-	-
1010000	ELEC PLANT IN SERV	3380004	SOLAR PANELS	SG	56	1	16	4	7	25	3	0	-
1010000	ELEC PLANT IN SERV	3380004	SOLAR PANELS	UT	292	-	-	-	-	292	-	-	-
1010000	ELEC PLANT IN SERV	3380005	COLLECTOR SYSTEM - SOLAR	UT	134	-	-	-	-	134	-	-	-
1010000	ELEC PLANT IN SERV	3380007	INVERTERS - SOLAR	UT	38	-	-	-	-	38	-	-	-
1010000	ELEC PLANT IN SERV	3380008	ACCESSORY ELECTRIC EQUIPMENT - SOLAR	UT	28	-	-	-	-	28	-	-	-
1010000	ELEC PLANT IN SERV	3380011	COMMUNICATION EQUIPMENT - SOLAR	OR	83	-	83	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3380018	INVERTERS - SOLAR - LSHLD IMPRV	OR	609	-	609	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3381900	LAND - WIND PRODUCTION	SG	7,774	108	2,158	570	1,034	3,466	437	0	-
1010000	ELEC PLANT IN SERV	3382000	LAND RIGHTS - WIND PRODUCTION	SG	12,774	177	3,546	937	1,700	5,696	719	1	-
1010000	ELEC PLANT IN SERV	3382001	WATER RIGHTS - WIND PRODUCTION	SG	0	0	0	0	0	0	0	0	-
1010000	ELEC PLANT IN SERV	3382100	STRUCTURES AND IMPROVEMENTS - WIND	SG	409,039	5,670	113,531	30,005	54,421	182,377	23,017	17	-
1010000	ELEC PLANT IN SERV	3382300	WIND TURBINES	SG	2,279,704	31,602	632,745	167,230	303,306	1,016,445	128,283	93	-
1010000	ELEC PLANT IN SERV	3382301	WIND TURBINES - GENERATORS	SG	189,742	2,630	52,664	13,919	25,244	84,600	10,677	8	-
1010000	ELEC PLANT IN SERV	3382400	WIND TOWERS AND FIXTURES	SG	748,654	10,378	207,793	54,918	99,606	333,800	42,128	30	-
1010000	ELEC PLANT IN SERV	3382600	COLLECTOR SYSTEM - WIND	SG	271,334	3,761	75,310	19,904	36,100	120,979	15,268	11	-
1010000	ELEC PLANT IN SERV	3382700	GSU AND ASSOC EQUIP - WIND	SG	44,989	624	12,487	3,300	5,986	20,059	2,532	2	-
1010000	ELEC PLANT IN SERV	3382800	INVERTERS - WIND	SG	5,509	76	1,529	404	733	2,456	310	0	-
1010000	ELEC PLANT IN SERV	3382900	ACCESSORY ELECTRIC EQUIPMENT - WIND	SG	11,544	160	3,204	847	1,536	5,147	650	0	-
1010000	ELEC PLANT IN SERV	3383000	COMPUTER HARDWARE - WIND	SG	418	6	116	31	56	186	24	0	-
1010000	ELEC PLANT IN SERV	3383100	COMPUTER SOFTWARE (MISC) - WIND	SG	296	4	82	22	39	132	17	0	-
1010000	ELEC PLANT IN SERV	3383200	COMMUNICATION EQUIPMENT - WIND	SG	2,941	41	816	216	391	1,311	165	0	-
1010000	ELEC PLANT IN SERV	3383205	COMM EQUIP - MOBILE RADIOS - WIND	SG	72	1	20	5	10	32	4	0	-
1010000	ELEC PLANT IN SERV	3383300	MISC POWER PLANT EQUIP - WIND	SG	17,449	242	4,843	1,280	2,322	7,780	982	1	-
1010000	ELEC PLANT IN SERV	3390000	LAND - OTHER REN	SG	214	3	59	16	28	95	12	0	-
1010000	ELEC PLANT IN SERV	3390001	LAND RIGHTS - OTHER REN	SG	40,982	568	11,375	3,006	5,452	18,272	2,306	2	-
1010000	ELEC PLANT IN SERV	3390002	STRUCTURES AND IMPROVEMENTS - OTHER REN	SG	8,560	119	2,376	628	1,139	3,817	482	0	-
1010000	ELEC PLANT IN SERV	3390003	FUEL HOLDERS - OTHER REN	SG	58,577	812	16,258	4,297	7,793	26,117	3,296	2	-
1010000	ELEC PLANT IN SERV	3390004	BOILER PLANT EQUIPMENT - OTHER REN	SG	2,605	36	723	191	347	1,161	147	0	-
1010000	ELEC PLANT IN SERV	3390006	GENERATORS - OTHER REN	SG	35,971	499	9,984	2,639	4,786	16,038	2,024	1	-
1010000	ELEC PLANT IN SERV	3390008	ACCESSORY ELECTRIC EQUIPMENT - OTHER REN	SG	8,555	119	2,375	628	1,138	3,814	481	0	-
1010000	ELEC PLANT IN SERV	3390009	COMPUTER HARDWARE - OTHER REN	SG	5	0	1	0	1	2	0	0	-
1010000	ELEC PLANT IN SERV	3390011	COMMUNICATION EQUIPMENT - OTHER REN	SG	984	14	273	72	131	439	55	0	-
1010000	ELEC PLANT IN SERV	3390012	MISC POWER PLANT EQUIP - OTHER REN	SG	1,352	19	375	99	180	603	76	0	-
1010000	ELEC PLANT IN SERV	3390015	COMM EQUIP - MOBILE RADIOS - OTHER REN	SG	22	0	6	2	3	10	1	0	-
1010000	ELEC PLANT IN SERV	3401000	LAND OWNED IN FEE	SG	6,548	91	1,818	480	871	2,920	368	0	-
1010000	ELEC PLANT IN SERV	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	32,709	453	9,079	2,399	4,352	14,584	1,841	1	-
1010000	ELEC PLANT IN SERV	3410000	STRUCTURES & IMPROVEMENTS	SG	175,538	2,433	48,722	12,877	23,355	78,267	9,878	7	-
1010000	ELEC PLANT IN SERV	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	16,439	228	4,563	1,206	2,187	7,330	925	1	-

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1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	IDU	1,000	-	-	-	-	-	1,000	-	-
1010000	ELEC PLANT IN SERV	3430000	PRIME MOVERS	SG	1,165,620	16,158	323,525	85,505	155,081	519,712	65,592	47	-
1010000	ELEC PLANT IN SERV	3440000	GENERATORS	SG	435,568	6,038	120,894	31,952	57,951	194,205	24,510	18	-
1010000	ELEC PLANT IN SERV	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	215,022	2,981	59,681	15,773	28,608	95,871	12,100	9	-
1010000	ELEC PLANT IN SERV	3451000	COMPUTER HARDWARE - OTHER PROD	SG	223	3	62	16	30	99	13	0	-
1010000	ELEC PLANT IN SERV	3452000	COMPUTER SOFTWARE (MISC) - OTHER PROD	SG	16	0	4	1	2	7	1	0	-
1010000	ELEC PLANT IN SERV	3453000	COMMUNICATION EQUIPMENT - OTHER PROD	SG	2,582	36	717	189	343	1,151	145	0	-
1010000	ELEC PLANT IN SERV	3453005	COMM EQUIP - MOBILE RADIOS - OTHER PROD	SG	67	1	18	5	9	30	4	0	-
1010000	ELEC PLANT IN SERV	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	12,978	180	3,602	952	1,727	5,786	730	1	-
1010000	ELEC PLANT IN SERV	3500000	LAND AND LAND RIGHTS	SG	841	12	233	62	112	375	47	0	-
1010000	ELEC PLANT IN SERV	3501000	LAND OWNED IN FEE	SG	64,017	887	17,768	4,696	8,517	28,543	3,602	3	-
1010000	ELEC PLANT IN SERV	3502000	LAND RIGHTS	SG	375,057	5,199	104,099	27,513	49,900	167,226	21,105	15	-
1010000	ELEC PLANT IN SERV	3511000	COMPUTER HARDWARE - TRANS	SG	67	1	19	5	9	30	4	0	-
1010000	ELEC PLANT IN SERV	3512000	COMPUTER SOFTWARE (MISC) - TRANS	SG	9	0	3	1	1	4	1	0	-
1010000	ELEC PLANT IN SERV	3512001	MONARCH EMS/SCADA	SG	42,351	587	11,755	3,107	5,635	18,883	2,383	2	-
1010000	ELEC PLANT IN SERV	3512002	OMS - OPERATIONS MAPPING SYSTEM	SG	10,386	144	2,883	762	1,382	4,631	584	0	-
1010000	ELEC PLANT IN SERV	3512003	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	10,149	141	2,817	744	1,350	4,525	571	0	-
1010000	ELEC PLANT IN SERV	3513000	COMMUNICATION EQUIPMENT - TRANS	SG	229,583	3,183	63,722	16,841	30,545	102,364	12,919	9	-
1010000	ELEC PLANT IN SERV	3513005	COMM EQUIP - MOBILE RADIOS - TRANS	SG	48	1	13	3	6	21	3	0	-
1010000	ELEC PLANT IN SERV	3520000	STRUCTURES & IMPROVEMENTS	SG	475,456	6,591	131,966	34,878	63,258	211,990	26,755	19	-
1010000	ELEC PLANT IN SERV	3530000	STATION EQUIPMENT	SG	2,790,345	38,681	774,476	204,689	371,245	1,244,124	157,018	114	-
1010000	ELEC PLANT IN SERV	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	181,936	2,522	50,497	13,346	24,206	81,119	10,238	7	-
1010000	ELEC PLANT IN SERV	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	27,696	384	7,687	2,032	3,685	12,349	1,558	1	-
1010000	ELEC PLANT IN SERV	3540000	TOWERS AND FIXTURES	SG	2,589,458	35,896	718,719	189,952	344,517	1,154,555	145,713	105	-
1010000	ELEC PLANT IN SERV	3550000	POLES AND FIXTURES	SG	1,559,871	21,623	432,951	114,426	207,535	695,495	87,777	63	-
1010000	ELEC PLANT IN SERV	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	2,376,247	32,940	659,541	174,312	316,151	1,059,491	133,716	97	-
1010000	ELEC PLANT IN SERV	3570000	UNDERGROUND CONDUIT	SG	3,924	54	1,089	288	522	1,750	221	0	-
1010000	ELEC PLANT IN SERV	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	9,084	126	2,521	666	1,209	4,050	511	0	-
1010000	ELEC PLANT IN SERV	3590000	ROADS AND TRAILS	SG	12,141	168	3,370	891	1,615	5,413	683	0	-
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	IDU	1	-	-	-	-	-	1	-	-
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	OR	8	-	8	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	UT	168	-	-	-	-	168	-	-	-
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	WYP	4	-	-	-	4	-	-	-	-
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	WYU	2	-	-	-	2	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	CA	1,606	1,606	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	IDU	502	-	-	-	-	-	502	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	OR	10,163	-	10,163	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	UT	31,571	-	-	-	-	31,571	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WA	2,209	-	-	2,209	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WYP	847	-	-	-	847	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WYU	638	-	-	-	638	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	CA	1,204	1,204	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	IDU	1,845	-	-	-	-	-	1,845	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	OR	6,479	-	6,479	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	UT	13,597	-	-	-	-	13,597	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WA	625	-	-	625	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WYP	5,098	-	-	-	5,098	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WYU	7,048	-	-	-	7,048	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	CA	9,054	9,054	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	IDU	4,333	-	-	-	-	-	4,333	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	OR	39,449	-	39,449	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	UT	72,123	-	-	-	-	72,123	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WA	9,551	-	-	9,551	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WYP	19,812	-	-	-	19,812	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WYU	5,027	-	-	-	5,027	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	CA	47,418	47,418	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	IDU	50,160	-	-	-	-	-	50,160	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	OR	321,866	-	321,866	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	UT	625,243	-	-	-	-	625,243	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WA	93,079	-	-	93,079	-	-	-	-	-

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	IDU	1,000	-	-	-	-	-	1,000	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WYP	147,001	-	-	-	147,001	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WYU	20,413	-	-	-	20,413	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	1,024	1,024	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	602	-	-	-	-	-	602	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	4,781	-	4,781	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	8,533	-	-	-	-	8,533	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	1,675	-	-	1,675	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	2,315	-	-	-	2,315	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	339	-	-	-	339	-	-	-	-
1010000	ELEC PLANT IN SERV	3631000	COMPUTER HARDWARE - DIST	CA	32	32	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3631000	COMPUTER HARDWARE - DIST	IDU	258	-	-	-	-	-	258	-	-
1010000	ELEC PLANT IN SERV	3631000	COMPUTER HARDWARE - DIST	OR	561	-	561	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3631000	COMPUTER HARDWARE - DIST	UT	465	-	-	-	-	465	-	-	-
1010000	ELEC PLANT IN SERV	3631000	COMPUTER HARDWARE - DIST	WA	336	-	-	336	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3631000	COMPUTER HARDWARE - DIST	WYP	823	-	-	-	823	-	-	-	-
1010000	ELEC PLANT IN SERV	3631000	COMPUTER HARDWARE - DIST	WYU	56	-	-	-	56	-	-	-	-
1010000	ELEC PLANT IN SERV	3632000	COMPUTER SOFTWARE (MISC) - DIST	OR	89	-	89	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3632000	COMPUTER SOFTWARE (MISC) - DIST	UT	1	-	-	-	-	1	-	-	-
1010000	ELEC PLANT IN SERV	3632000	COMPUTER SOFTWARE (MISC) - DIST	WA	1	-	-	1	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3632000	COMPUTER SOFTWARE (MISC) - DIST	WYP	81	-	-	-	81	-	-	-	-
1010000	ELEC PLANT IN SERV	3632001	AFPR - AUTOMATED FACILITY POINT RECORDS	SNPD	4,410	353	1,128	221	357	2,150	201	-	-
1010000	ELEC PLANT IN SERV	3632004	ARCOS	SNPD	3,083	247	788	155	249	1,503	140	-	-
1010000	ELEC PLANT IN SERV	3632005	CADOPS - COMPUTER-ASSISTED DISTRIBUTION	SNPD	16,796	1,346	4,296	843	1,358	8,188	764	-	-
1010000	ELEC PLANT IN SERV	3632006	FNP - FIELDNETPRO METER READING SYSTEM	SNPD	2,908	233	744	146	235	1,418	132	-	-
1010000	ELEC PLANT IN SERV	3632007	FPI - FACILITIES POINTS INSPECTION	SNPD	2,020	162	517	101	163	985	92	-	-
1010000	ELEC PLANT IN SERV	3632008	IEE - ITRON ENTERPRISE ADDITION	CN	4,934	108	1,487	339	341	2,447	211	-	-
1010000	ELEC PLANT IN SERV	3632009	ITRON METER READING SOFTWARE	CN	5,868	129	1,769	403	406	2,910	251	-	-
1010000	ELEC PLANT IN SERV	3632010	GWD - GRAPHICAL WORK DESIGN	SNPD	6,632	532	1,696	333	536	3,233	302	-	-
1010000	ELEC PLANT IN SERV	3633000	COMMUNICATION EQUIPMENT - DIST	CA	9,262	9,262	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3633000	COMMUNICATION EQUIPMENT - DIST	IDU	10,163	-	-	-	-	-	10,163	-	-
1010000	ELEC PLANT IN SERV	3633000	COMMUNICATION EQUIPMENT - DIST	OR	62,394	-	62,394	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3633000	COMMUNICATION EQUIPMENT - DIST	UT	53,470	-	-	-	-	53,470	-	-	-
1010000	ELEC PLANT IN SERV	3633000	COMMUNICATION EQUIPMENT - DIST	WA	8,235	-	-	8,235	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3633000	COMMUNICATION EQUIPMENT - DIST	WYP	17,194	-	-	-	17,194	-	-	-	-
1010000	ELEC PLANT IN SERV	3633000	COMMUNICATION EQUIPMENT - DIST	WYU	3,347	-	-	-	3,347	-	-	-	-
1010000	ELEC PLANT IN SERV	3633005	COMM EQUIP - MOBILE RADIOS - DIST	CA	10	10	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3633005	COMM EQUIP - MOBILE RADIOS - DIST	IDU	104	-	-	-	-	-	104	-	-
1010000	ELEC PLANT IN SERV	3633005	COMM EQUIP - MOBILE RADIOS - DIST	OR	23	-	23	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3633005	COMM EQUIP - MOBILE RADIOS - DIST	UT	449	-	-	-	-	449	-	-	-
1010000	ELEC PLANT IN SERV	3633005	COMM EQUIP - MOBILE RADIOS - DIST	WA	3	-	-	3	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3633005	COMM EQUIP - MOBILE RADIOS - DIST	WYP	124	-	-	-	124	-	-	-	-
1010000	ELEC PLANT IN SERV	3633005	COMM EQUIP - MOBILE RADIOS - DIST	WYU	37	-	-	-	37	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	CA	189,949	189,949	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	IDU	125,320	-	-	-	-	-	125,320	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	OR	652,713	-	652,713	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	UT	554,717	-	-	-	-	554,717	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WA	157,650	-	-	157,650	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WYP	172,845	-	-	-	172,845	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WYU	33,558	-	-	-	33,558	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	142,314	142,314	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	51,879	-	-	-	-	-	51,879	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	422,910	-	422,910	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	340,001	-	-	-	-	340,001	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	112,914	-	-	112,914	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	126,163	-	-	-	126,163	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	16,034	-	-	-	16,034	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	CA	25,352	25,352	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	IDU	18,543	-	-	-	-	-	18,543	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	OR	134,111	-	134,111	-	-	-	-	-	-

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	IDU	1,000	-	-	-	-	-	1,000	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	UT	317,035	-	-	-	-	317,035	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WA	26,828	-	-	26,828	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WYP	34,853	-	-	-	34,853	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WYU	5,975	-	-	-	5,975	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	26,114	26,114	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	41,620	-	-	-	-	-	41,620	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	255,830	-	255,830	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	852,611	-	-	-	-	852,611	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	40,442	-	-	40,442	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	58,121	-	-	-	58,121	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	20,826	-	-	-	20,826	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	CA	64,371	64,371	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	IDU	103,068	-	-	-	-	-	103,068	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	OR	570,187	-	570,187	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	UT	757,445	-	-	-	-	757,445	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WA	141,107	-	-	141,107	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WYP	127,506	-	-	-	127,506	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WYU	17,551	-	-	-	17,551	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	CA	13,294	13,294	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	IDU	11,223	-	-	-	-	-	11,223	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	OR	128,955	-	128,955	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	UT	118,801	-	-	-	-	118,801	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WA	31,076	-	-	31,076	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WYP	22,857	-	-	-	22,857	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WYU	5,356	-	-	-	5,356	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	CA	20,198	20,198	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	IDU	48,267	-	-	-	-	-	48,267	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	OR	265,019	-	265,019	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	UT	363,459	-	-	-	-	363,459	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WA	56,549	-	-	56,549	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WYP	44,266	-	-	-	44,266	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WYU	15,101	-	-	-	15,101	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	CA	9,780	9,780	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	IDU	20,795	-	-	-	-	-	20,795	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	OR	111,653	-	111,653	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	UT	149,393	-	-	-	-	149,393	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	WA	17,219	-	-	17,219	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	WYP	16,518	-	-	-	16,518	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	WYU	3,243	-	-	-	3,243	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	CA	291	291	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	174	-	-	-	-	-	174	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	OR	2,756	-	2,756	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	UT	4,196	-	-	-	-	4,196	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WA	547	-	-	547	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	930	-	-	-	930	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	151	-	-	-	151	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	4,116	4,116	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	920	-	-	-	-	-	920	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	25,386	-	25,386	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	21,677	-	-	-	-	21,677	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	4,051	-	-	4,051	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	9,469	-	-	-	9,469	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	2,360	-	-	-	2,360	-	-	-	-
1010000	ELEC PLANT IN SERV	3890000	LAND AND LAND RIGHTS	IDU	89	-	-	-	-	-	89	-	-
1010000	ELEC PLANT IN SERV	3890000	LAND AND LAND RIGHTS	OR	228	-	228	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3890000	LAND AND LAND RIGHTS	UT	1,327	-	-	-	-	1,327	-	-	-
1010000	ELEC PLANT IN SERV	3890000	LAND AND LAND RIGHTS	WYU	434	-	-	-	434	-	-	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	CA	997	997	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	CN	1,129	25	340	78	78	560	48	-	-

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	IDU	1,000	-	-	-	-	-	1,000	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	IDU	100	-	-	-	-	-	100	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	OR	8,856	-	8,856	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	SG	0	0	0	0	0	0	0	0	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	SO	7,516	228	2,098	528	913	3,346	404	0	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	UT	2,677	-	-	-	-	2,677	-	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	WA	1,099	-	-	1,099	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	WYP	2,902	-	-	-	2,902	-	-	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	WYU	221	-	-	-	221	-	-	-	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	IDU	5	-	-	-	-	-	5	-	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	OR	1	-	1	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	SG	1	0	0	0	0	1	0	0	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	SO	95	3	27	7	12	42	5	0	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	UT	96	-	-	-	-	96	-	-	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	WYP	52	-	-	-	52	-	-	-	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	WYU	22	-	-	-	22	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	CA	3,921	3,921	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	CN	8,219	180	2,477	565	569	4,076	352	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	IDU	13,443	-	-	-	-	-	13,443	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	OR	38,806	-	38,806	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SE	941	12	252	63	135	422	57	0	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SG	12,024	167	3,337	882	1,600	5,361	677	0	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SO	114,874	3,483	32,060	8,063	13,957	51,131	6,176	3	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	UT	48,521	-	-	-	-	48,521	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WA	11,928	-	-	11,928	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WYP	16,707	-	-	-	16,707	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WYU	4,435	-	-	-	4,435	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	513	513	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	IDU	334	-	-	-	-	-	334	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	5,690	-	5,690	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	2,197	67	613	154	267	978	118	0	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	33	-	-	-	-	33	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	2,574	-	-	2,574	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	4,768	-	-	-	4,768	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	CA	99	99	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	CN	307	7	93	21	21	152	13	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	IDU	66	-	-	-	-	-	66	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	OR	1,045	-	1,045	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	SE	4	0	1	0	1	2	0	0	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	SG	1,978	27	549	145	263	882	111	0	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	SO	15,649	474	4,367	1,098	1,901	6,965	841	0	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	UT	1,027	-	-	-	-	1,027	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WA	46	-	-	46	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WYP	452	-	-	-	452	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WYU	41	-	-	-	41	-	-	-	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	CN	0	0	0	0	0	0	0	-	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	SG	21	0	6	2	3	9	1	0	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	SO	730	22	204	51	89	325	39	0	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	UT	1	-	-	-	-	1	-	-	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	WYU	8	-	-	-	8	-	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	CA	53	53	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	IDU	294	-	-	-	-	-	294	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	1,482	-	1,482	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SE	25	0	7	2	4	11	2	0	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	475	7	132	35	63	212	27	0	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	506	15	141	36	62	225	27	0	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	2,943	-	-	-	-	2,943	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	284	-	-	284	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	609	-	-	-	609	-	-	-	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	OR	324	-	324	-	-	-	-	-	-

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	IDU	1,000	-	-	-	-	-	1,000	-	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	SO	176	5	49	12	21	78	9	0	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	UT	621	-	-	-	-	621	-	-	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	WYP	19	-	-	-	19	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	344	344	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	761	-	-	-	-	-	761	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	5,484	-	5,484	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	71	1	19	5	10	32	4	0	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	7,644	106	2,122	561	1,017	3,408	430	0	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	937	28	262	66	114	417	50	0	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	7,594	-	-	-	-	7,594	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	1,223	-	-	1,223	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	2,473	-	-	-	2,473	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	294	-	-	-	294	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	1,187	1,187	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	4,578	-	-	-	-	-	4,578	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	12,945	-	12,945	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	13	0	4	1	2	6	1	0	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	7,592	105	2,107	557	1,010	3,385	427	0	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	461	14	129	32	56	205	25	0	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	23,909	-	-	-	-	23,909	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	3,297	-	-	3,297	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	5,936	-	-	-	5,936	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	1,302	-	-	-	1,302	-	-	-	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	OR	343	-	343	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	SE	4	0	1	0	1	2	0	0	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	SG	4,661	65	1,294	342	620	2,078	262	0	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	UT	149	-	-	-	-	149	-	-	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	WA	86	-	-	86	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	CA	624	624	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	IDU	2,452	-	-	-	-	-	2,452	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	OR	5,752	-	5,752	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SE	41	1	11	3	6	19	2	0	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SG	1,989	28	552	146	265	887	112	0	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SO	1,051	32	293	74	128	468	56	0	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	UT	12,633	-	-	-	-	12,633	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WA	986	-	-	986	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WYP	4,449	-	-	-	4,449	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WYU	1,113	-	-	-	1,113	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	286	286	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	236	-	-	-	-	-	236	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	722	-	722	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SE	6	0	2	0	1	3	0	0	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	1,708	24	474	125	227	762	96	0	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	61	2	17	4	7	27	3	0	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	663	-	-	-	-	663	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	120	-	-	120	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYP	397	-	-	-	397	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	121	-	-	-	121	-	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	497	-	497	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	553	8	153	41	74	247	31	0	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	138	4	38	10	17	61	7	0	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	2,049	-	-	-	-	2,049	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	353	-	-	353	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	WYP	163	-	-	-	163	-	-	-	-
1010000	ELEC PLANT IN SERV	3923000	TRANSPORTATION EQUIPMENT	SO	2,993	91	835	210	364	1,332	161	0	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	CA	108	108	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	IDU	1,184	-	-	-	-	-	1,184	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	OR	3,975	-	3,975	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	SG	7,816	108	2,169	573	1,040	3,485	440	0	-

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(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	IDU	1,000	-	-	-	-	-	1,000	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	SO	283	9	79	20	34	126	15	0	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	UT	4,142	-	-	-	-	4,142	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WA	1,030	-	-	1,030	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WYP	1,474	-	-	-	1,474	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WYU	1	-	-	-	1	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	1,119	1,119	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	2,329	-	-	-	-	-	2,329	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	10,470	-	10,470	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	126	2	34	8	18	56	8	0	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	22,431	311	6,226	1,645	2,984	10,001	1,262	1	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	1,604	49	448	113	195	714	86	0	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	16,190	-	-	-	-	16,190	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	2,865	-	-	2,865	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	4,134	-	-	-	4,134	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	232	-	-	-	232	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	CA	787	787	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	IDU	1,432	-	-	-	-	-	1,432	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	OR	10,535	-	10,535	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SE	1,225	15	329	82	176	550	74	0	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SG	5,905	82	1,639	433	786	2,633	332	0	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SO	4,436	135	1,238	311	539	1,975	239	0	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	UT	9,900	-	-	-	-	9,900	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WA	1,445	-	-	1,445	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WYP	3,396	-	-	-	3,396	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WYU	80	-	-	-	80	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	CA	2,235	2,235	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	IDU	3,366	-	-	-	-	-	3,366	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	OR	14,554	-	14,554	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SG	163	2	45	12	22	73	9	0	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SO	1,542	47	430	108	187	687	83	0	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	UT	16,173	-	-	-	-	16,173	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WA	3,436	-	-	3,436	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYP	5,823	-	-	-	5,823	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYU	1,052	-	-	-	1,052	-	-	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	390	-	-	-	-	-	390	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	916	-	916	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	124	2	35	9	17	55	7	0	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	1,590	-	-	-	-	1,590	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	1,665	1,665	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	4,997	-	-	-	-	-	4,997	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	13,630	-	13,630	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	1,040	14	289	76	138	464	59	0	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	2,221	67	620	156	270	989	119	0	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	19,520	-	-	-	-	19,520	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	3,173	-	-	3,173	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	7,411	-	-	-	7,411	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	537	-	-	-	537	-	-	-	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	OR	1,388	-	1,388	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	SG	3,010	42	836	221	401	1,342	169	0	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	UT	1,083	-	-	-	-	1,083	-	-	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	WYP	608	-	-	-	608	-	-	-	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	OR	1,217	-	1,217	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SG	20,192	280	5,604	1,481	2,686	9,003	1,136	1	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	2,691	-	-	-	-	2,691	-	-	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WA	404	-	-	404	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	830	-	-	-	830	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	1,814	1,814	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	3,598	-	-	-	-	-	3,598	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	12,284	-	12,284	-	-	-	-	-	-

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Allocation Method - Factor 2020 Protocol
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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	IDU	1,000	-	-	-	-	-	1,000	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	325	5	90	24	43	145	18	0	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	1,276	39	356	90	155	568	69	0	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	17,208	-	-	-	-	17,208	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	2,250	-	-	2,250	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	5,409	-	-	-	5,409	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	1,372	-	-	-	1,372	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOV	CA	880	880	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOV	IDU	2,149	-	-	-	-	-	2,149	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOV	OR	5,443	-	5,443	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOV	SE	75	1	20	5	11	34	5	0	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOV	SG	7,209	100	2,001	529	959	3,214	406	0	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOV	SO	644	20	180	45	78	287	35	0	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOV	UT	9,565	-	-	-	-	9,565	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOV	WA	1,358	-	-	1,358	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOV	WYP	3,258	-	-	-	3,258	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOV	WYU	830	-	-	-	830	-	-	-	-
1010000	ELEC PLANT IN SERV	3971001	COMPUTER HARDWARE - GENERAL	CN	1,836	40	553	126	127	911	79	-	-
1010000	ELEC PLANT IN SERV	3971001	COMPUTER HARDWARE - GENERAL	SE	9	0	3	1	1	4	1	0	-
1010000	ELEC PLANT IN SERV	3971001	COMPUTER HARDWARE - GENERAL	SO	52,308	1,586	14,599	3,671	6,355	23,283	2,812	1	-
1010000	ELEC PLANT IN SERV	3971001	COMPUTER HARDWARE - GENERAL	UT	5	-	-	-	-	5	-	-	-
1010000	ELEC PLANT IN SERV	3972001	COMPUTER SOFTWARE (MISC) - GENERAL	CN	24	1	7	2	2	12	1	-	-
1010000	ELEC PLANT IN SERV	3972001	COMPUTER SOFTWARE (MISC) - GENERAL	SE	9	0	2	1	1	4	1	0	-
1010000	ELEC PLANT IN SERV	3972001	COMPUTER SOFTWARE (MISC) - GENERAL	SO	26,937	817	7,518	1,891	3,273	11,990	1,448	1	-
1010000	ELEC PLANT IN SERV	3972002	RWT - RCMS WORK TRACKING	SO	11,249	341	3,140	790	1,367	5,007	605	0	-
1010000	ELEC PLANT IN SERV	3972003	SAP - SAP	SO	183,307	5,558	51,159	12,866	22,271	81,592	9,856	5	-
1010000	ELEC PLANT IN SERV	3972004	VMWARE	SO	7,454	226	2,080	523	906	3,318	401	0	-
1010000	ELEC PLANT IN SERV	3972005	AUGMENTED REALITY	SO	12,894	391	3,599	905	1,567	5,739	693	0	-
1010000	ELEC PLANT IN SERV	3972008	FMS - FUEL MANAGEMENT SYSTEM	SO	3,293	100	919	231	400	1,466	177	0	-
1010000	ELEC PLANT IN SERV	3972011	CSS - CUSTOMER SERVICE SYSTEM	CN	149,328	3,277	45,007	10,258	10,331	74,055	6,399	-	-
1010000	ELEC PLANT IN SERV	3972013	NODAL PRICING SOFTWARE	SG	3,281	45	911	241	437	1,463	185	0	-
1010000	ELEC PLANT IN SERV	3972014	ESM-IRP	SO	3,649	111	1,018	256	443	1,624	196	0	-
1010000	ELEC PLANT IN SERV	3972015	CELONIS	SO	4,359	132	1,217	306	530	1,940	234	0	-
1010000	ELEC PLANT IN SERV	3972016	IAM - SCHEDULING/TAGGING SYSTEM	SO	1,342	41	375	94	163	598	72	0	-
1010000	ELEC PLANT IN SERV	3972017	AZURE B2C - IDENTITY MGT	SO	1,429	43	399	100	174	636	77	0	-
1010000	ELEC PLANT IN SERV	3972018	PCI GENTRADER	SO	3,114	94	869	219	378	1,386	167	0	-
1010000	ELEC PLANT IN SERV	3972019	ITOA	SO	5,534	168	1,544	388	672	2,463	298	0	-
1010000	ELEC PLANT IN SERV	3972020	TSSA - TRUESIGHT SERVER AUTOMATION	SO	1,390	42	388	98	169	619	75	0	-
1010000	ELEC PLANT IN SERV	3972021	EDW - ENTERPRISE DATA WAREHOUSE	SO	5,877	178	1,640	412	714	2,616	316	0	-
1010000	ELEC PLANT IN SERV	3972022	SCHOOL - SUBSTATION/CIRCUIT HISTORY OF O	SO	2,416	73	674	170	294	1,075	130	0	-
1010000	ELEC PLANT IN SERV	3972023	AMBIENT AI	SO	1,324	40	370	93	161	589	71	0	-
1010000	ELEC PLANT IN SERV	3972024	GRID - NET POWER COST MODELING	SO	8,999	273	2,511	632	1,093	4,005	484	0	-
1010000	ELEC PLANT IN SERV	3972025	MOIP - MID_OFFICE IMPROVEMENT PROJECT -	SO	10,577	321	2,952	742	1,285	4,708	569	0	-
1010000	ELEC PLANT IN SERV	3972026	SETTLECORE	SG	1,194	17	331	88	159	532	67	0	-
1010000	ELEC PLANT IN SERV	3972027	PADMS - POLE ATTACHMENT MANAGEMENT SYSTE	SO	1,915	58	534	134	233	852	103	0	-
1010000	ELEC PLANT IN SERV	3972028	SPS-MOBILE WORK MGT/MOBILITY-CLICK/SINGL	SO	13,486	409	3,764	947	1,639	6,003	725	0	-
1010000	ELEC PLANT IN SERV	3972029	TIBCO - CONTENT MANAGEMENT SYSTEM	SO	7,830	237	2,185	550	951	3,485	421	0	-
1010000	ELEC PLANT IN SERV	3972030	TWBS - TRANSMISSION WHOLESALE BILLING SY	SG	1,600	22	444	117	213	713	90	0	-
1010000	ELEC PLANT IN SERV	3972031	UII - UTILITY INTERNATIONAL FORECASTING	SO	9,405	285	2,625	660	1,143	4,186	506	0	-
1010000	ELEC PLANT IN SERV	3972032	CUSTSTMT-CUSTOMER STATEMENT FORMATTING	CN	2,629	58	792	181	182	1,304	113	-	-
1010000	ELEC PLANT IN SERV	3972033	WEB - WEB INFRASTRUCTURE AND APPLICATION	SO	12,006	364	3,351	843	1,459	5,344	646	0	-
1010000	ELEC PLANT IN SERV	3972034	FILENET P8 DOCUMENT MANAGEMENT	SO	7,015	213	1,958	492	852	3,122	377	0	-
1010000	ELEC PLANT IN SERV	3972035	VERVE OPERATIONAL TECHNOLOGY SYSTEM	SG	503	7	140	37	67	224	28	0	-
1010000	ELEC PLANT IN SERV	3972036	ARCFM SOFTWARE	SO	3,978	121	1,110	279	483	1,771	214	0	-
1010000	ELEC PLANT IN SERV	3972039	AMI METERING SOFTWARE	CN	48,722	1,069	14,685	3,347	3,371	24,163	2,088	-	-
1010000	ELEC PLANT IN SERV	3972040	BIG DATA & ANALYTICS	SO	7,686	233	2,145	539	934	3,421	413	0	-
1010000	ELEC PLANT IN SERV	3972041	CES - CUSTOMER EXPERIENCE SYSTEM	CN	10,516	231	3,169	722	727	5,215	451	-	-
1010000	ELEC PLANT IN SERV	3972042	MAPAPPS - MAPPING SYSTEMS APPLICATION	SO	7,595	230	2,120	533	923	3,381	408	0	-
1010000	ELEC PLANT IN SERV	3972043	CUSTOMER CONTACTS	CN	3,903	86	1,176	268	270	1,935	167	-	-
1010000	ELEC PLANT IN SERV	3972045	C&T - ENERGY TRADING SYSTEM	SO	21,506	652	6,002	1,509	2,613	9,573	1,156	1	-

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Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	IDU	1,000	-	-	-	-	-	1,000	-	-
1010000	ELEC PLANT IN SERV	3972046	CYME GATEWAY	SO	923	28	258	65	112	411	50	0	-
1010000	ELEC PLANT IN SERV	3972047	M365	SO	3,712	113	1,036	261	451	1,652	200	0	-
1010000	ELEC PLANT IN SERV	3972048	ADS	SO	2,594	79	724	182	315	1,155	139	0	-
1010000	ELEC PLANT IN SERV	3972049	TECHNOSYLVA	SO	24,694	749	6,892	1,733	3,000	10,992	1,328	1	-
1010000	ELEC PLANT IN SERV	3972050	SITUATIONAL AWARENESS	SO	1,247	38	348	88	152	555	67	0	-
1010000	ELEC PLANT IN SERV	3972051	MAXIMO	SO	21,096	640	5,888	1,481	2,563	9,390	1,134	1	-
1010000	ELEC PLANT IN SERV	3972052	AURORA	SO	1,962	59	548	138	238	873	105	0	-
1010000	ELEC PLANT IN SERV	3972053	CXP - CUSTOMER EXPERIENCE (CX) PLATFORM	CN	4,718	104	1,422	324	326	2,340	202	-	-
1010000	ELEC PLANT IN SERV	3972054	SOLARWINDS	SG	1,525	21	423	112	203	680	86	0	-
1010000	ELEC PLANT IN SERV	3972055	APIM - ASSET PERFORMANCE & INVESTMENT MA	SO	5,538	168	1,546	389	673	2,465	298	0	-
1010000	ELEC PLANT IN SERV	3972056	ENTERPRISE GEOGRAPHIC INFORMATION SYSTEM	SO	1,141	35	319	80	139	508	61	0	-
1010000	ELEC PLANT IN SERV	3972057	FOUNDRY	SO	14,767	448	4,121	1,036	1,794	6,573	794	0	-
1010000	ELEC PLANT IN SERV	3972058	PSP - PUBLIC SAFETY PORTAL	SO	11,077	336	3,091	777	1,346	4,930	596	0	-
1010000	ELEC PLANT IN SERV	3972059	ACD--CALL CENTER AUTOMATED CALL DISTRIBUT	CN	4,132	91	1,245	284	286	2,049	177	-	-
1010000	ELEC PLANT IN SERV	3973001	COMMUNICATION EQUIPMENT - GENERAL	CA	10	10	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3973001	COMMUNICATION EQUIPMENT - GENERAL	CN	3,140	69	947	216	217	1,557	135	-	-
1010000	ELEC PLANT IN SERV	3973001	COMMUNICATION EQUIPMENT - GENERAL	IDU	689	-	-	-	-	-	689	-	-
1010000	ELEC PLANT IN SERV	3973001	COMMUNICATION EQUIPMENT - GENERAL	OR	3,782	-	3,782	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3973001	COMMUNICATION EQUIPMENT - GENERAL	SE	260	3	70	17	37	117	16	0	-
1010000	ELEC PLANT IN SERV	3973001	COMMUNICATION EQUIPMENT - GENERAL	SG	4,019	56	1,115	295	535	1,792	226	0	-
1010000	ELEC PLANT IN SERV	3973001	COMMUNICATION EQUIPMENT - GENERAL	SO	69,538	2,108	19,407	4,881	8,449	30,952	3,739	2	-
1010000	ELEC PLANT IN SERV	3973001	COMMUNICATION EQUIPMENT - GENERAL	UT	5,657	-	-	-	-	5,657	-	-	-
1010000	ELEC PLANT IN SERV	3973001	COMMUNICATION EQUIPMENT - GENERAL	WA	49	-	-	49	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3973001	COMMUNICATION EQUIPMENT - GENERAL	WYP	32	-	-	-	32	-	-	-	-
1010000	ELEC PLANT IN SERV	3973001	COMMUNICATION EQUIPMENT - GENERAL	WYU	1,589	-	-	-	1,589	-	-	-	-
1010000	ELEC PLANT IN SERV	3973005	COMM EQUIP - MOBILE RADIOS - GENERAL	SO	45	1	13	3	5	20	2	0	-
1010000	ELEC PLANT IN SERV	3973005	COMM EQUIP - MOBILE RADIOS - GENERAL	UT	8	-	-	-	-	8	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	CA	66	66	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	CN	80	2	24	5	6	40	3	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	IDU	73	-	-	-	-	-	73	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	OR	1,379	-	1,379	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SE	4	0	1	0	1	2	0	0	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SG	2,944	41	817	216	392	1,313	166	0	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SO	3,658	111	1,021	257	444	1,628	197	0	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	UT	1,766	-	-	-	-	1,766	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WA	210	-	-	210	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WYP	278	-	-	-	278	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WYU	17	-	-	-	17	-	-	-	-
1010000	ELEC PLANT IN SERV	3992100	LAND OWNED IN FEE	SE	1,823	23	489	122	261	818	110	0	-
1010000 Total					**37,167,085**	**967,721**	**10,561,704**	**2,688,522**	**4,562,117**	**16,360,088**	**2,025,872**	**1,060**	**-**
1019000	ELEC PLT IN SERV-OTH	140129	ELECTRIC PLANT IN SERVICE - OTHER	SO	(2,268)	(69)	(633)	(159)	(276)	(1,009)	(122)	(0)	-
1019000	ELEC PLT IN SERV-OTH	140139	PRODUCTION PLANT-NON-RECONCILED	SG	(21,447)	(297)	(5,953)	(1,573)	(2,853)	(9,562)	(1,207)	(1)	-
1019000	ELEC PLT IN SERV-OTH	140149	TRANS PLANT NON-RECONCILED	SG	(5,648)	(78)	(1,568)	(414)	(752)	(2,518)	(318)	(0)	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	CA	(264)	(264)	-	-	-	-	-	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	IDU	(143)	-	-	-	-	-	(143)	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	OR	(1,461)	-	(1,461)	-	-	-	-	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	UT	(3,147)	-	-	-	-	(3,147)	-	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	WA	(294)	-	-	(294)	-	-	-	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	WYU	(325)	-	-	-	(325)	-	-	-	-
1019000 Total					**(34,997)**	**(708)**	**(9,614)**	**(2,441)**	**(4,206)**	**(16,237)**	**(1,790)**	**(1)**	**-**
1020000	ELEC PL PUR OR SLD	0	ELECTRIC PLANT PURCHASED OR SOLD	SG	(553)	(8)	(154)	(41)	(74)	(247)	(31)	(0)	-
1020000	ELEC PL PUR OR SLD	140708	CONTRA ELEC PLANT PURCH OR SOLD - LOSS	SG	553	8	154	41	74	247	31	0	-
1020000 Total					**0**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	CA	25,782	25,782	-	-	-	-	-	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	IDU	7,633	-	-	-	-	-	7,633	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	OR	123,643	-	123,643	-	-	-	-	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	UT	148,979	-	-	-	-	148,979	-	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WA	7,784	-	-	7,784	-	-	-	-	-

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Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	IDU	1,000	-	-	-	-	-	1,000	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WYU	9,751	-	-	-	9,751	-	-	-	-
1061000 Total					**323,572**	**25,782**	**123,643**	**7,784**	**9,751**	**148,979**	**7,633**	**-**	**-**
1062000	TRAN COMP CONST NOT	0	TRANSM COMPLETED CONSTRUCTN NOT CLASSIF	SG	697,048	9,663	193,470	51,133	92,739	310,791	39,224	28	-
1062000 Total					**697,048**	**9,663**	**193,470**	**51,133**	**92,739**	**310,791**	**39,224**	**28**	**-**
1063000	PROD COMP CONST NO	0	PROD COMPLETED CONSTRUCTN NOT CLASSIFIED	SG	197,462	2,737	54,807	14,485	26,272	88,042	11,112	8	-
1063000 Total					**197,462**	**2,737**	**54,807**	**14,485**	**26,272**	**88,042**	**11,112**	**8**	**-**
1064000	GEN COMP CONST NOT	0	GENERAL COMPLETED CONSTRUCTN NOT CLASSI	SO	200,602	6,082	55,986	14,080	24,373	89,290	10,786	6	-
1064000 Total					**200,602**	**6,082**	**55,986**	**14,080**	**24,373**	**89,290**	**10,786**	**6**	**-**
Grand Total					**38,550,771**	**1,011,278**	**10,979,995**	**2,773,562**	**4,711,046**	**16,980,953**	**2,092,837**	**1,101**	**-**

B9. CAPITAL LEASE PLANT

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Capital Lease (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1011000	PRPTY UND CPTL LSS	3908220	(FINANCE LEASES-BLDGS)	OR	5,159	-	5,159	-	-	-	-	-	-
1011000	PRPTY UND CPTL LSS	3908230	(FINANCE LEASES-GAS)	SG	12,159	169	3,375	892	1,618	5,421	684	0	-
1011000	PRPTY UND CPTL LSS	3908250	(FINANCE LEASES-OTHER)	IDU	2,405	-	-	-	-	-	2,405	-	-
1011000	PRPTY UND CPTL LSS	3908250	(FINANCE LEASES-OTHER)	OR	6,079	-	6,079	-	-	-	-	-	-
1011000	PRPTY UND CPTL LSS	3908250	(FINANCE LEASES-OTHER)	UT	7,320	-	-	-	-	7,320	-	-	-
1011000	PRPTY UND CPTL LSS	3908250	(FINANCE LEASES-OTHER)	WA	2,495	-	-	2,495	-	-	-	-	-
1011000	PRPTY UND CPTL LSS	3908250	(FINANCE LEASES-OTHER)	WYP	3,402	-	-	-	3,402	-	-	-	-
1011000	PRPTY UND CPTL LSS	3908250	(FINANCE LEASES-OTHER)	WYU	408	-	-	-	408	-	-	-	-
1011000 Total					**39,427**	**169**	**14,613**	**3,387**	**5,428**	**12,742**	**3,089**	**0**	**-**
1011500	CAP LEASES–ACCM AMRT	3908220	(FINANCE LEASES-BLDGS)	OR	(2,931)	-	(2,931)	-	-	-	-	-	-
1011500	CAP LEASES–ACCM AMRT	3908230	(FINANCE LEASES-GAS)	SG	(5,924)	(82)	(1,644)	(435)	(788)	(2,641)	(333)	(0)	-
1011500	CAP LEASES–ACCM AMRT	3908250	(FINANCE LEASES-OTHER)	IDU	(303)	-	-	-	-	-	(303)	-	-
1011500	CAP LEASES–ACCM AMRT	3908250	(FINANCE LEASES-OTHER)	OR	(491)	-	(491)	-	-	-	-	-	-
1011500	CAP LEASES–ACCM AMRT	3908250	(FINANCE LEASES-OTHER)	UT	(638)	-	-	-	-	(638)	-	-	-
1011500	CAP LEASES–ACCM AMRT	3908250	(FINANCE LEASES-OTHER)	WA	(225)	-	-	(225)	-	-	-	-	-
1011500	CAP LEASES–ACCM AMRT	3908250	(FINANCE LEASES-OTHER)	WYP	(331)	-	-	-	(331)	-	-	-	-
1011500	CAP LEASES–ACCM AMRT	3908250	(FINANCE LEASES-OTHER)	WYU	(63)	-	-	-	(63)	-	-	-	-
1011500 Total					**(10,906)**	**(82)**	**(5,066)**	**(660)**	**(1,182)**	**(3,280)**	**(636)**	**(0)**	**-**
1011900	PRPTY UND CPTL LSS-O	142794	FIN LEASE ROU ASSETS (COST)-OTHER-TEMP	OR	3,146	-	3,146	-	-	-	-	-	-
1011900	PRPTY UND CPTL LSS-O	142794	FIN LEASE ROU ASSETS (COST)-OTHER-TEMP	SG	4,793	66	1,330	352	638	2,137	270	0	-
1011900 Total					**7,939**	**66**	**4,476**	**352**	**638**	**2,137**	**270**	**0**	**-**
1011950	CAP LEASES–ACCM AMRT	142894	Fin Lease ROU Assets (A/D)-Other-Temp	OR	(3,146)	-	(3,146)	-	-	-	-	-	-
1011950	CAP LEASES–ACCM AMRT	142894	Fin Lease ROU Assets (A/D)-Other-Temp	SG	(4,793)	(66)	(1,330)	(352)	(638)	(2,137)	(270)	(0)	-
1011950 Total					**(7,939)**	**(66)**	**(4,476)**	**(352)**	**(638)**	**(2,137)**	**(270)**	**(0)**	**-**
Grand Total					**28,521**	**86**	**9,547**	**2,727**	**4,245**	**9,462**	**2,453**	**0**	**-**

B10.PLANT HELD FOR FUTURE USE

PACIFICORP

Plant Held for Future Use (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1050000	EL PLT HLD FTR USE	3501000	LAND OWNED IN FEI	SG	707	10	196	52	94	315	40	0	-
1050000	EL PLT HLD FTR USE	3502000	LAND RIGHTS	SG	755	10	209	55	100	336	42	0	-
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEI	OR	4,562	-	4,562	-	-	-	-	-	-
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEI	UT	5,168	-	-	-	-	5,168	-	-	-
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEI	WYP	1	-	-	-	1	-	-	-	-
1050000 Total					**11,193**	**20**	**4,968**	**107**	**195**	**5,820**	**82**	**0**	**-**
Grand Total					**11,193**	**20**	**4,968**	**107**	**195**	**5,820**	**82**	**0**	**-**

B11. MISC. DEFERRED DEBITS

PACIFICORP

Deferred Debits (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1861000	MS DEF DB-OTH WIP	185016	EMISSION REDUCTION CREDITS PURCHASED	SE	2,347	29	629	157	337	1,053	141	0	-
1861000	MS DEF DB-OTH WIP	185017	ERCs - Impairment Reserve	SE	(2,040)	(26)	(547)	(137)	(293)	(915)	(123)	(0)	-
1861000 Total					**307**	**4**	**82**	**21**	**44**	**137**	**18**	**0**	**-**
1861200	FINANCING COSTS DEFR	185025	FINANCING COST DEFERRED	SO	885	27	247	62	107	394	48	0	-
1861200	FINANCING COSTS DEFR	185026	DEFERRED - S-3 SHELF REGISTRATION COSTS	SO	122	4	34	9	15	54	7	0	-
1861200	FINANCING COSTS DEFR	185027	UNAMORTIZED CREDIT AGREEMENT COSTS	OTHER	3,272	-	-	-	-	-	-	-	3,272
1861200	FINANCING COSTS DEFR	185029	UNAMORTIZED PCRB MADE CONVERSION COST	OTHER	9	-	-	-	-	-	-	-	9
1861200 Total					**4,287**	**31**	**281**	**71**	**122**	**448**	**54**	**0**	**3,280**
1868000	MISC DF DR-OTH-CST	185336	BOGUS CREEK	SG	602	8	167	44	80	268	34	0	-
1868000	MISC DF DR-OTH-CST	185337	POINT-TO-POINT TRANS RESERVATIONS	SG	7,681	106	2,132	563	1,022	3,425	432	0	-
1868000	MISC DF DR-OTH-CST	185351	BPA LT TRANSMISSION PREPAID	OTHER	3,320	-	-	-	-	-	-	-	3,320
1868000	MISC DF DR-OTH-CST	185359	LT Lake Side 2 Maint. Prepayment	SG	11,539	160	3,203	846	1,535	5,145	649	0	-
1868000	MISC DF DR-OTH-CST	185360	LT LAKE SIDE MAINT PREPAYMENT	SG	430	6	119	32	57	192	24	0	-
1868000	MISC DF DR-OTH-CST	185361	LT CHEHALIS CSA MAINT. PREPAYMENT	SG	22,140	307	6,145	1,624	2,946	9,871	1,246	1	-
1868000	MISC DF DR-OTH-CST	185362	LT Currant Creek CSA Maint Prepayment	SG	23,887	331	6,630	1,752	3,178	10,650	1,344	1	-
1868000	MISC DF DR-OTH-CST	185371	LT Chehalis CSA Prepaid O&M	SG	2,249	31	624	165	299	1,003	127	0	-
1868000	MISC DF DR-OTH-CST	185372	LT Currant Creek CSA Prepaid O&M	SG	1,061	15	294	78	141	473	60	0	-
1868000	MISC DF DR-OTH-CST	185400	Trans Readiness Security - Due to ESM	SG	24,483	339	6,795	1,796	3,257	10,916	1,378	1	-
1868000	MISC DF DR-OTH-CST	185401	Trans Readiness Security - ESM Rec	SG	(24,483)	(339)	(6,795)	(1,796)	(3,257)	(10,916)	(1,378)	(1)	-
1868000	MISC DF DR-OTH-CST	185402	Trans Sec - Site Control - Due to ESM	SG	470	7	130	34	63	210	26	0	-
1868000	MISC DF DR-OTH-CST	185403	Trans Sec - Site Control - ESM Rec	SG	(470)	(7)	(130)	(34)	(63)	(210)	(26)	(0)	-
1868000	MISC DF DR-OTH-CST	185551	LT Prepaid-FSA Capital - Dunlap	SG	5,738	80	1,592	421	763	2,558	323	0	-
1868000	MISC DF DR-OTH-CST	185552	LT Prepaid-FSA Capital - Ekola Flats	SG	5,241	73	1,455	384	697	2,337	295	0	-
1868000	MISC DF DR-OTH-CST	185554	LT Prepaid-FSA Capital - Foote Creek	SG	1,428	20	396	105	190	637	80	0	-
1868000	MISC DF DR-OTH-CST	185557	LT Prepaid-FSA Capital - Glenrock I	SG	4,633	64	1,286	340	616	2,066	261	0	-
1868000	MISC DF DR-OTH-CST	185558	LT Prepaid-FSA Capital - Glenrock III	SG	1,920	27	533	141	255	856	108	0	-
1868000	MISC DF DR-OTH-CST	185561	LT Prepaid-FSA Capital - Goodnoe Hills	SG	4,471	62	1,241	328	595	1,994	252	0	-
1868000	MISC DF DR-OTH-CST	185564	LT Prepaid-FSA Capital - High Plains	SG	3,985	55	1,106	292	530	1,777	224	0	-
1868000	MISC DF DR-OTH-CST	185567	LT Prepaid-FSA Capital - Leaning Juniper	SG	5,174	72	1,436	380	688	2,307	291	0	-
1868000	MISC DF DR-OTH-CST	185570	LT Prepaid-FSA Capital - Marengo I	SG	7,215	100	2,003	529	960	3,217	406	0	-
1868000	MISC DF DR-OTH-CST	185571	LT Prepaid-FSA Capital - Marengo II	SG	3,740	52	1,038	274	498	1,668	210	0	-
1868000	MISC DF DR-OTH-CST	185574	LT Prepaid-FSA Capital - McFadden Ridge	SG	1,778	25	494	130	237	793	100	0	-
1868000	MISC DF DR-OTH-CST	185576	LT Prepaid-FSA Capital - Pryor Mtn	SG	7,487	104	2,078	549	996	3,338	421	0	-
1868000	MISC DF DR-OTH-CST	185577	LT Prepaid-FSA Capital - Rolling Hills	SG	4,533	63	1,258	333	603	2,021	255	0	-
1868000	MISC DF DR-OTH-CST	185580	LT Prepaid-FSA Capital - Seven Mile I	SG	5,169	72	1,435	379	688	2,305	291	0	-
1868000	MISC DF DR-OTH-CST	185581	LT Prepaid-FSA Capital - Seven Mile II	SG	856	12	238	63	114	382	48	0	-
1868000	MISC DF DR-OTH-CST	185584	LT Prepaid-FSA Capital - TB Flats I	SG	(1,511)	(21)	(419)	(111)	(201)	(674)	(85)	(0)	-
1868000	MISC DF DR-OTH-CST	185585	LT Prepaid-FSA Capital - TB Flats II	SG	4,350	60	1,207	319	579	1,939	245	0	-
1868000	MISC DF DR-OTH-CST	185586	LT Prepaid-FSA Capital - Rock River	SG	(31)	(0)	(9)	(2)	(4)	(14)	(2)	(0)	-
1868000 Total					**139,083**	**1,882**	**37,682**	**9,959**	**18,063**	**60,532**	**7,640**	**6**	**3,320**
1869000	MISC DF DR-OTH-NC	185334	HERMISTON SWAP	SG	1,903	26	528	140	253	848	107	0	-
1869000 Total					**1,903**	**26**	**528**	**140**	**253**	**848**	**107**	**0**	**-**
Grand Total					**145,579**	**1,943**	**38,573**	**10,190**	**18,482**	**61,966**	**7,819**	**6**	**6,600**

B13. MATERIALS & SUPPLIES

PACIFICORP

Material & Supplies (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1511120	COAL INVNTRY-HUNTER	0	COAL INVENTORY - HUNTER	SE	106,936	1,337	28,683	7,173	15,336	47,965	6,436	5	-
1511120 Total					**106,936**	**1,337**	**28,683**	**7,173**	**15,336**	**47,965**	**6,436**	**5**	**-**
1511130	COAL INVNTRY-HTG	0	COAL INVENTORY - HUNTINGTON	SE	75,987	950	20,382	5,097	10,897	34,083	4,573	4	-
1511130 Total					**75,987**	**950**	**20,382**	**5,097**	**10,897**	**34,083**	**4,573**	**4**	**-**
1511140	COAL INVNTRY-JB	0	COAL INVENTORY - JIM BRIDGER	SE	38,273	478	10,266	2,567	5,489	17,167	2,303	2	-
1511140 Total					**38,273**	**478**	**10,266**	**2,567**	**5,489**	**17,167**	**2,303**	**2**	**-**
1511160	COAL INVNTRY-NAU	0	COAL INVENTORY - NAUGHTON	SE	15,367	192	4,122	1,031	2,204	6,893	925	1	-
1511160 Total					**15,367**	**192**	**4,122**	**1,031**	**2,204**	**6,893**	**925**	**1**	**-**
1511180	COAL INVNTRY-WYODAK	0	COAL INVENTORY - WYODAK	SE	0	0	0	0	0	0	0	0	-
1511180 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-**
1511300	COAL INVNTRY-COLSTRI	0	COAL INVENTORY - COLSTIP	SE	2,328	29	624	156	334	1,044	140	0	-
1511300 Total					**2,328**	**29**	**624**	**156**	**334**	**1,044**	**140**	**0**	**-**
1511400	COAL INVNTRY-CRAIG	0	COAL INVENTORY - CRAIG	SE	4,676	58	1,254	314	671	2,098	281	0	-
1511400 Total					**4,676**	**58**	**1,254**	**314**	**671**	**2,098**	**281**	**0**	**-**
1511600	COAL INVNTRY-DJ	0	COAL INVENTORY - DAVE JOHNSTON	SE	14,755	184	3,958	990	2,116	6,618	888	1	-
1511600 Total					**14,755**	**184**	**3,958**	**990**	**2,116**	**6,618**	**888**	**1**	**-**
1511700	COAL INVNTRY-RG	0	COAL INVENTORY ROCK GARDEN PILE	SE	35,415	443	9,499	2,376	5,079	15,885	2,131	2	-
1511700 Total					**35,415**	**443**	**9,499**	**2,376**	**5,079**	**15,885**	**2,131**	**2**	**-**
1511900	COAL INVNTRY-HAYDEN	0	COAL INVENTORY - HAYDEN	SE	550	7	147	37	79	246	33	0	-
1511900 Total					**550**	**7**	**147**	**37**	**79**	**246**	**33**	**0**	**-**
1512180	NATURAL GAS-CLAY BAS	0	NATURAL GAS - CLAY BASIN	SE	1,356	17	364	91	195	608	82	0	-
1512180 Total					**1,356**	**17**	**364**	**91**	**195**	**608**	**82**	**0**	**-**
1514000	FUEL STK-FUEL OIL	0	FUEL STOCK COAL MINE	SE	1,901	24	510	127	273	852	114	0	-
1514000 Total					**1,901**	**24**	**510**	**127**	**273**	**852**	**114**	**0**	**-**
1514300	OIL INVNTRY-COLSTRIP	0	OIL INVENTORY - COLSTRIP	SE	71	1	19	5	10	32	4	0	-
1514300 Total					**71**	**1**	**19**	**5**	**10**	**32**	**4**	**0**	**-**
1514400	OIL INVENTORY-CRAIG	0	OIL INVENTORY - CRAIG	SE	48	1	13	3	7	21	3	0	-
1514400 Total					**48**	**1**	**13**	**3**	**7**	**21**	**3**	**0**	**-**
1514900	OIL INVENTORY-HAYDEN	0	OIL INVENTORY - HAYDEN	SE	67	1	18	4	10	30	4	0	-
1514900 Total					**67**	**1**	**18**	**4**	**10**	**30**	**4**	**0**	**-**
1541000	PLNT M&S STK CNTRL	0	MATERIAL CONTROL ADJUST	SO	(148)	(4)	(41)	(10)	(18)	(66)	(8)	(0)	-
1541000	PLNT M&S STK CNTRL	1510	JIM BRIDGER STORE ROOM	SG	27,882	387	7,739	2,045	3,710	12,432	1,569	1	-
1541000	PLNT M&S STK CNTRL	1515	DAVE JOHNSTON STORE ROOM	SG	24,451	339	6,786	1,794	3,253	10,902	1,376	1	-
1541000	PLNT M&S STK CNTRL	1520	WYODAK STORE ROOM	SG	7,764	108	2,155	570	1,033	3,462	437	0	-
1541000	PLNT M&S STK CNTRL	1525	GADSBY STORE ROOM	SG	4,940	68	1,371	362	657	2,203	278	0	-
1541000	PLNT M&S STK CNTRL	1530	CARBON STORE ROOM	SG	1	0	0	0	0	1	0	0	-
1541000	PLNT M&S STK CNTRL	1535	NAUGHTON STORE ROOM	SG	15,083	209	4,186	1,106	2,007	6,725	849	1	-
1541000	PLNT M&S STK CNTRL	1540	HUNTINGTON STORE ROOM	SG	23,386	324	6,491	1,716	3,111	10,427	1,316	1	-
1541000	PLNT M&S STK CNTRL	1545	HUNTER STORE ROOM	SG	35,635	494	9,891	2,614	4,741	15,889	2,005	1	-
1541000	PLNT M&S STK CNTRL	1550	BLUNDELL STORE ROOM	SG	1,496	21	415	110	199	667	84	0	-
1541000	PLNT M&S STK CNTRL	1565	CURRANT CREEK PLANT	SG	4,506	62	1,251	331	599	2,009	254	0	-
1541000	PLNT M&S STK CNTRL	1570	LAKESIDE PLANT	SG	7,831	109	2,173	574	1,042	3,491	441	0	-
1541000	PLNT M&S STK CNTRL	1580	CHEHALIS PLANT	SG	4,113	57	1,142	302	547	1,834	231	0	-
1541000	PLNT M&S STK CNTRL	1675	HYDRO EAST - UTAH	SG	7	0	2	1	1	3	0	0	-
1541000	PLNT M&S STK CNTRL	1680	HYDRO EAST - IDAHO	SG	38	1	10	3	5	17	2	0	-
1541000	PLNT M&S STK CNTRL	1700	LEANING JUNIPER STOREROOM	SG	218	3	60	16	29	97	12	0	-
1541000	PLNT M&S STK CNTRL	1705	GOODNOE HILLS WIND	SG	107	1	30	8	14	48	6	0	-
1541000	PLNT M&S STK CNTRL	1715	MARENGO WIND	SG	252	3	70	18	34	112	14	0	-
1541000	PLNT M&S STK CNTRL	1720	Foote Creek	SG	5	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL	1725	Glenrock/Rolling Hills	SG	1,124	16	312	82	150	501	63	0	-
1541000	PLNT M&S STK CNTRL	1730	Seven Mile Hill	SG	495	7	137	36	66	221	28	0	-
1541000	PLNT M&S STK CNTRL	1735	Ekola Flats	SG	5	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL	1740	High Plains/McFadden	SG	356	5	99	26	47	159	20	0	-
1541000	PLNT M&S STK CNTRL	1745	Dunlap Wind Project	SG	442	6	123	32	59	197	25	0	-
1541000	PLNT M&S STK CNTRL	1750	TB Flats 1 & 2	SG	4	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL	1760	Cedar Springs II	SG	1,511	21	419	111	201	674	85	0	-
1541000	PLNT M&S STK CNTRL	1765	Pryor Mountain	SG	12	0	3	1	2	5	1	0	-

PACIFICORP

Material & Supplies (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1541000	PLNT M&S STK CNTRL	1775	Rock Creek 1 & 2	SG	676	9	188	50	90	302	38	0	-
1541000	PLNT M&S STK CNTRL	2005	CASPER STORE ROOM	WYP	954	-	-	-	954	-	-	-	-
1541000	PLNT M&S STK CNTRL	2010	BUFFALO STORE ROOM	WYP	245	-	-	-	245	-	-	-	-
1541000	PLNT M&S STK CNTRL	2015	DOUGLAS STORE ROOM	WYP	429	-	-	-	429	-	-	-	-
1541000	PLNT M&S STK CNTRL	2020	CODY STORE ROOM	WYP	1,268	-	-	-	1,268	-	-	-	-
1541000	PLNT M&S STK CNTRL	2030	WORLAND STORE ROOM	WYP	1,067	-	-	-	1,067	-	-	-	-
1541000	PLNT M&S STK CNTRL	2035	RIVERTON STORE ROOM	WYP	868	-	-	-	868	-	-	-	-
1541000	PLNT M&S STK CNTRL	2040	EVANSTON STORE ROOM	WYU	2,690	-	-	-	2,690	-	-	-	-
1541000	PLNT M&S STK CNTRL	2045	KEMMERER STORE ROOM	WYU	14	-	-	-	14	-	-	-	-
1541000	PLNT M&S STK CNTRL	2050	PINEDALE STORE ROOM	WYU	1,445	-	-	-	1,445	-	-	-	-
1541000	PLNT M&S STK CNTRL	2060	ROCK SPRINGS STORE ROOM	WYP	3,191	-	-	-	3,191	-	-	-	-
1541000	PLNT M&S STK CNTRL	2065	RAWLINS STORE ROOM	WYP	999	-	-	-	999	-	-	-	-
1541000	PLNT M&S STK CNTRL	2070	LARAMIE STORE ROOM	WYP	954	-	-	-	954	-	-	-	-
1541000	PLNT M&S STK CNTRL	2075	REXBERG STORE ROOM	IDU	3,737	-	-	-	-	-	3,737	-	-
1541000	PLNT M&S STK CNTRL	2080	MUDLAKE STORE ROOM	IDU	1	-	-	-	-	-	1	-	-
1541000	PLNT M&S STK CNTRL	2085	SHELLY STORE ROOM	IDU	2,553	-	-	-	-	-	2,553	-	-
1541000	PLNT M&S STK CNTRL	2090	PRESTON STORE ROOM	IDU	115	-	-	-	-	-	115	-	-
1541000	PLNT M&S STK CNTRL	2095	LAVA HOT SPRINGS STORE ROOM	IDU	313	-	-	-	-	-	313	-	-
1541000	PLNT M&S STK CNTRL	2100	MONTPELIER STORE ROOM	IDU	471	-	-	-	-	-	471	-	-
1541000	PLNT M&S STK CNTRL	2110	BRIDGERLAND STORE ROOM	UT	4,537	-	-	-	-	4,537	-	-	-
1541000	PLNT M&S STK CNTRL	2205	TREMONTON STORE ROOM	UT	1,241	-	-	-	-	1,241	-	-	-
1541000	PLNT M&S STK CNTRL	2210	OGDEN STORE ROOM	UT	4,361	-	-	-	-	4,361	-	-	-
1541000	PLNT M&S STK CNTRL	2215	LAYTON STORE ROOM	UT	2,919	-	-	-	-	2,919	-	-	-
1541000	PLNT M&S STK CNTRL	2220	SALT LAKE METRO STORE ROOM	UT	14,266	-	-	-	-	14,266	-	-	-
1541000	PLNT M&S STK CNTRL	2230	JORDAN VALLEY STORE ROOM	UT	2,682	-	-	-	-	2,682	-	-	-
1541000	PLNT M&S STK CNTRL	2235	PARK CITY STORE ROOM	UT	8,247	-	-	-	-	8,247	-	-	-
1541000	PLNT M&S STK CNTRL	2240	TOOELE STORE ROOM	UT	1,213	-	-	-	-	1,213	-	-	-
1541000	PLNT M&S STK CNTRL	2245	WASATCH RESTORATION CENTER	UT	1,760	-	-	-	-	1,760	-	-	-
1541000	PLNT M&S STK CNTRL	2400	PLNT M&S STK CNTRL EAGLE MOUNTAIN	UT	1,047	-	-	-	-	1,047	-	-	-
1541000	PLNT M&S STK CNTRL	2405	AMERICAN FORK STORE ROOM	UT	4,699	-	-	-	-	4,699	-	-	-
1541000	PLNT M&S STK CNTRL	2410	SANTAQUIN STORE ROOM	UT	1,721	-	-	-	-	1,721	-	-	-
1541000	PLNT M&S STK CNTRL	2415	DELTA STORE ROOM	UT	560	-	-	-	-	560	-	-	-
1541000	PLNT M&S STK CNTRL	2420	VERNAL STORE ROOM	UT	1,621	-	-	-	-	1,621	-	-	-
1541000	PLNT M&S STK CNTRL	2425	PRICE STORE ROOM	UT	1,351	-	-	-	-	1,351	-	-	-
1541000	PLNT M&S STK CNTRL	2430	MOAB STORE ROOM	UT	2,693	-	-	-	-	2,693	-	-	-
1541000	PLNT M&S STK CNTRL	2435	BLANDING STORE ROOM	UT	223	-	-	-	-	223	-	-	-
1541000	PLNT M&S STK CNTRL	2445	RICHFIELD STORE ROOM	UT	130	-	-	-	-	130	-	-	-
1541000	PLNT M&S STK CNTRL	2450	CEDAR CITY STORE ROOM	UT	8,208	-	-	-	-	8,208	-	-	-
1541000	PLNT M&S STK CNTRL	2455	MILFORD STORE ROOM	UT	0	-	-	-	-	0	-	-	-
1541000	PLNT M&S STK CNTRL	2460	WASHINGTON STORE ROOM	UT	2,630	-	-	-	-	2,630	-	-	-
1541000	PLNT M&S STK CNTRL	2620	WALLA WALLA STORE ROOM	WA	4,158	-	-	4,158	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2630	YAKIMA STORE ROOM	WA	700	-	-	700	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2635	ENTERPRISE STORE ROOM	OR	538	-	538	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2640	PENDLETON STORE ROOM	OR	2,077	-	2,077	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2650	HOOD RIVER STORE ROOM	OR	974	-	974	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2655	PORTLAND METRO - STORE ROOM	OR	21,783	-	21,783	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2660	ASTORIA STORE ROOM	OR	3,550	-	3,550	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2665	MADRAS STORE ROOM	OR	122	-	122	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2670	PRINEVILLE STORE ROOM	OR	1	-	1	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2675	BEND STORE ROOM	OR	4,961	-	4,961	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2805	ALBANY STORE ROOM	OR	445	-	445	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2810	LINCOLN CITY STORE ROOM	OR	519	-	519	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2830	ROSEBURG STORE ROOM	OR	6,574	-	6,574	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2835	COOS BAY STORE ROOM	OR	1,481	-	1,481	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2840	GRANTS PASS STORE ROOM	OR	2,200	-	2,200	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2845	MEDFORD STORE ROOM	OR	40,991	-	40,991	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2850	KLAMATH FALLS STORE ROOM	OR	4,994	-	4,994	-	-	-	-	-	-

PACIFICORP

Material & Supplies (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1541000	PLNT M&S STK CNTRL	2855	LAKEVIEW STORE ROOM	OR	145	-	145	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2860	ALTURAS STORE ROOM	CA	134	134	-	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2865	MT SHASTA STORE ROOM	CA	371	371	-	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2870	YREKA STORE ROOM	CA	3,516	3,516	-	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2875	CRESENT CITY STORE ROOM	CA	1,410	1,410	-	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5005	TREMONTON STORE ROOM	SO	146	4	41	10	18	65	8	0	-
1541000	PLNT M&S STK CNTRL	5110	MATERIAL PACKAGING CENTER - WEST	OR	0	-	0	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5115	DEMC - SLC	SNPD	113	9	29	6	9	55	5	-	-
1541000	PLNT M&S STK CNTRL	5120	DEMC - MEDFORD	OR	103	-	103	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5125	DEMC - OREGON	OR	28,599	-	28,599	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5130	MEDFORD HUB	OR	76,803	-	76,803	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5135	YAKIMA HUB	WA	26,621	-	-	26,621	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5140	PRESTON HUB	IDU	10,485	-	-	-	-	-	10,485	-	-
1541000	PLNT M&S STK CNTRL	5150	RICHFIELD HUB	UT	13,549	-	-	-	-	13,549	-	-	-
1541000	PLNT M&S STK CNTRL	5155	CASPER HUB	WYP	13,739	-	-	-	13,739	-	-	-	-
1541000	PLNT M&S STK CNTRL	5160	SALT LAKE METRO HUB	UT	80,920	-	-	-	-	80,920	-	-	-
1541000	PLNT M&S STK CNTRL	5300	METER TEST WAREHOUSE	UT	3	-	-	-	-	3	-	-	-
1541000 Total					**602,340**	**7,691**	**241,947**	**43,394**	**49,471**	**233,017**	**26,815**	**7**	**-**
1541500	OTHER M&S	0	M&S GLENROCK COAL MINE	SE	198	2	53	13	28	89	12	0	-
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STO(	SE	(198)	(2)	(53)	(13)	(28)	(89)	(12)	(0)	-
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STO(	SO	(1,354)	(41)	(378)	(95)	(165)	(603)	(73)	(0)	-
1541500 Total					**(1,354)**	**(41)**	**(378)**	**(95)**	**(165)**	**(603)**	**(73)**	**(0)**	**-**
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTOR	SG	(9,467)	(131)	(2,628)	(694)	(1,260)	(4,221)	(533)	(0)	-
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTOR	SO	(1,380)	(42)	(385)	(97)	(168)	(614)	(74)	(0)	-
1541900	PLNT M&S GEN JV CUT	120010	Minority Owned Plant M&S Inventory	SG	6,659	92	1,848	489	886	2,969	375	0	-
1541900 Total					**(4,187)**	**(81)**	**(1,164)**	**(303)**	**(541)**	**(1,866)**	**(232)**	**(0)**	**-**
1549900	CR-OBSOL&SURPL INV	102930	SB Asset # 120930	SO	(27)	(1)	(8)	(2)	(3)	(12)	(1)	(0)	-
1549900	CR-OBSOL&SURPL INV	120930	INVENTORY RESERVE POWER SUPPLY	SG	(151)	(2)	(42)	(11)	(20)	(67)	(8)	(0)	-
1549900	CR-OBSOL&SURPL INV	120930	INVENTORY RESERVE POWER SUPPLY	SO	(12)	(0)	(3)	(1)	(2)	(6)	(1)	(0)	-
1549900	CR-OBSOL&SURPL INV	120932	Inventory Reserve - RMP (T&D)	SNPD	(1,108)	(89)	(283)	(56)	(90)	(540)	(50)	-	-
1549900	CR-OBSOL&SURPL INV	120933	Inventory Reserve - PP (T&D)	SNPD	(623)	(50)	(159)	(31)	(50)	(304)	(28)	-	-
1549900 Total					**(1,922)**	**(142)**	**(496)**	**(101)**	**(165)**	**(929)**	**(89)**	**(0)**	**-**
1581300	ALLOW INVENTORY- CUR	0	1581300/0	OTHER	15,149	-	-	-	-	-	-	-	15,149
1581300	ALLOW INVENTORY- CUR	132097	Prepaid - CA GHG Retail	OTHER	11,848	-	-	-	-	-	-	-	11,848
1581300	ALLOW INVENTORY- CUR	132098	Prepaid - CA GHG Wholesale	OTHER	1,244	-	-	-	-	-	-	-	1,244
1581300	ALLOW INVENTORY- CUR	132099	Prepaid WA GHG Wholesale - Current	OTHER	20,974	-	-	-	-	-	-	-	20,974
1581300 Total					**49,215**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**49,215**
1581400	ALLOWANCE INVNTRY-NC	0	ALLOWANCE INVENTORY - NON-CURRENT	OTHER	13,131	-	-	-	-	-	-	-	13,131
1581400	ALLOWANCE INVNTRY-NC	134101	Prepaid CA GHG Wholesale - Non-Current	OTHER	1,654	-	-	-	-	-	-	-	1,654
1581400	ALLOWANCE INVNTRY-NC	134102	Prepaid WA GHG Wholesale - Non-Current	OTHER	12,629	-	-	-	-	-	-	-	12,629
1581400 Total					**27,414**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**27,414**
Grand Total					**969,235**	**11,149**	**319,768**	**62,867**	**91,297**	**363,163**	**44,340**	**21**	**76,629**

B14. CASH WORKING CAPITAL

PACIFICORP

Cash Working Capital (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1430000	OTHER ACCTS REC	0	OTHER ACCOUNTS RECEIVABLE	SO	32,628	989	9,106	2,290	3,964	14,523	1,754	1	-
1430000 Total					**32,628**	**989**	**9,106**	**2,290**	**3,964**	**14,523**	**1,754**	**1**	**-**
1431500	INC TAXES RECEIVABLE	0	INCOME TAXES RECEIVABLE	SO	(28)	(1)	(8)	(2)	(3)	(13)	(2)	(0)	-
1431500	INC TAXES RECEIVABLE	116133	InterCo State Tax Rec-(Even Years)- MEHC	SO	155	5	43	11	19	69	8	0	-
1431500	INC TAXES RECEIVABLE	116134	InterCo State Tax Rec -(Odd Years)- MEHC	SO	(54)	(2)	(15)	(4)	(7)	(24)	(3)	(0)	-
1431500 Total					**73**	**2**	**20**	**5**	**9**	**33**	**4**	**0**	**-**
1433000	JOINT OWNER REC	0	JOINT OWNER RECEIVABLE	SO	(65)	(2)	(18)	(5)	(8)	(29)	(4)	(0)	-
1433000 Total					**(65)**	**(2)**	**(18)**	**(5)**	**(8)**	**(29)**	**(4)**	**(0)**	**-**
1436000	OTH ACCT REC	0	OTHER ACCOUNTS RECEIVABLE	SO	177,382	5,378	49,505	12,450	21,551	78,954	9,537	5	-
1436000 Total					**177,382**	**5,378**	**49,505**	**12,450**	**21,551**	**78,954**	**9,537**	**5**	**-**
1437000	CSS OAR BILLINGS	0	CSS OAR BILLINGS	SO	11,531	350	3,218	809	1,401	5,132	620	0	-
1437000 Total					**11,531**	**350**	**3,218**	**809**	**1,401**	**5,132**	**620**	**0**	**-**
1437100	CSS OAR BILLINGS-WOR	0	OTHER ACCT REC CCS	SO	(67,338)	(2,042)	(18,793)	(4,726)	(8,181)	(29,973)	(3,621)	(2)	-
1437100 Total					**(67,338)**	**(2,042)**	**(18,793)**	**(4,726)**	**(8,181)**	**(29,973)**	**(3,621)**	**(2)**	**-**
2300000	ASSET RETIREMENT OBL	284915	ARO LIAB - DEER CREEK MINE RECLAMATION	OTHER	(2,032)	-	-	-	-	-	-	-	(2,032)
2300000 Total					**(2,032)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(2,032)**
2320000	ACCOUNTS PAYABLE	210460	JOINT OWNER RECEIVABLES - CREDIT	SE	(3,222)	(40)	(864)	(216)	(462)	(1,445)	(194)	(0)	-
2320000	ACCOUNTS PAYABLE	210669	Navajo Transitional Energy Co - NTEC	SE	(102)	(1)	(27)	(7)	(15)	(46)	(6)	(0)	-
2320000	ACCOUNTS PAYABLE	210677	Bronco Utah Operations LLC - Coal	SE	(3,781)	(47)	(1,014)	(254)	(542)	(1,696)	(228)	(0)	-
2320000	ACCOUNTS PAYABLE	210679	Coal Purchases - Platte River Pwr Auth	SE	(203)	(3)	(54)	(14)	(29)	(91)	(12)	(0)	-
2320000	ACCOUNTS PAYABLE	211108	UNION DUES/CONTRIBUTIONS WITHHOLDING	SO	1	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	211109	MET PAY HOME & AUTO WITHHOLDINGS	SO	(4)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	-
2320000	ACCOUNTS PAYABLE	211112	UNITED FUND/CHARITABLE WITHHOLDINGS	SO	1	0	0	0	0	1	0	0	-
2320000	ACCOUNTS PAYABLE	211115	Allstate Voluntary Benefit Withholdings	SO	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
2320000	ACCOUNTS PAYABLE	211116	DEPENDENT SUPPORT/LEVY WITHHOLDINGS	SO	(6)	(0)	(2)	(0)	(1)	(2)	(0)	(0)	-
2320000	ACCOUNTS PAYABLE	215077	K-PLUS EMPLOYER CONTRIBUTIONS - ENHANCE	SO	(715)	(22)	(200)	(50)	(87)	(318)	(38)	(0)	-
2320000	ACCOUNTS PAYABLE	215078	K-Plus Employer Contributions - Fixed	SO	(111)	(3)	(31)	(8)	(14)	(50)	(6)	(0)	-
2320000	ACCOUNTS PAYABLE	215080	METLIFE MEDICAL INSURANCE	SO	(4,187)	(127)	(1,169)	(294)	(509)	(1,864)	(225)	(0)	-
2320000	ACCOUNTS PAYABLE	215082	METLIFE DENTAL INSURANCE	SO	(85)	(3)	(24)	(6)	(10)	(38)	(5)	(0)	-
2320000	ACCOUNTS PAYABLE	215084	METLIFE VISION INSURANCE	SO	(369)	(11)	(103)	(26)	(45)	(164)	(20)	(0)	-
2320000	ACCOUNTS PAYABLE	215085	Western Utilities Dental Payable	SO	192	6	54	13	23	85	10	0	-
2320000	ACCOUNTS PAYABLE	215086	Western Utilities Vision Payable	SO	21	1	6	1	3	9	1	0	-
2320000	ACCOUNTS PAYABLE	215088	UWUA Health & Welfare Payable	SO	(10)	(0)	(3)	(1)	(1)	(5)	(1)	(0)	-
2320000	ACCOUNTS PAYABLE	215095	HMO HEALTH PLAN	SO	47	1	13	3	6	21	3	0	-
2320000	ACCOUNTS PAYABLE	215103	Bluegrass Coal Purchases	SE	(83)	(1)	(22)	(6)	(12)	(37)	(5)	(0)	-
2320000	ACCOUNTS PAYABLE	215112	Minnesota Life Insurance	SO	(69)	(2)	(19)	(5)	(8)	(31)	(4)	(0)	-
2320000	ACCOUNTS PAYABLE	215116	IBEW 57 MEDICAL INSURANCE	SO	(571)	(17)	(159)	(40)	(69)	(254)	(31)	(0)	-
2320000	ACCOUNTS PAYABLE	215350	"IBEW 57 HEALTH REIMBURSEMENT, CURRENT Y	SO	2	0	1	0	0	1	0	0	-
2320000	ACCOUNTS PAYABLE	215351	"IBEW 57 DEPENDENT CARE REIMBURSEMENT, (	SO	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	215356	"HEALTH REIMBURSEMENT, CURRENT YEAR"	SO	(60)	(2)	(17)	(4)	(7)	(27)	(3)	(0)	-
2320000	ACCOUNTS PAYABLE	215357	"DEPENDENT CARE REIMBURSEMENT, CURREN	SO	(16)	(1)	(5)	(1)	(2)	(7)	(1)	(0)	-
2320000	ACCOUNTS PAYABLE	215425	OR DOE Cool School Program	OTHER	(13)	-	-	-	-	-	-	-	(13)
2320000	ACCOUNTS PAYABLE	215439	Cal ISO Trans Payable	SG	(4,704)	(65)	(1,306)	(345)	(626)	(2,097)	(265)	(0)	-
2320000	ACCOUNTS PAYABLE	215850	Subscription Fee - OR Community Solar	OTHER	(244)	-	-	-	-	-	-	-	(244)
2320000	ACCOUNTS PAYABLE	215851	Participation Fee - OR Community Solar	OTHER	(1)	-	-	-	-	-	-	-	(1)
2320000	ACCOUNTS PAYABLE	235230	ACCRUAL - ROYALTIES	SE	(61)	(1)	(16)	(4)	(9)	(27)	(4)	(0)	-
2320000	ACCOUNTS PAYABLE	235599	Safety Award	SO	(772)	(23)	(215)	(54)	(94)	(344)	(42)	(0)	-
2320000	ACCOUNTS PAYABLE	240330	PROVISION FOR WORKERS' COMPENSATION	SO	(740)	(22)	(207)	(52)	(90)	(329)	(40)	(0)	-
2320000 Total					**(19,866)**	**(384)**	**(5,384)**	**(1,368)**	**(2,600)**	**(8,757)**	**(1,114)**	**(1)**	**(257)**
2533000	O DEF CR-MISC PPL	289517	TRAPPER MINE FINAL RECLAMATION	SE	(10,620)	(133)	(2,849)	(712)	(1,523)	(4,763)	(639)	(1)	-
2533000 Total					**(10,620)**	**(133)**	**(2,849)**	**(712)**	**(1,523)**	**(4,763)**	**(639)**	**(1)**	**-**
Grand Total					**121,692**	**4,159**	**34,805**	**8,743**	**14,613**	**55,120**	**6,538**	**3**	**(2,289)**

B15. MISC. RATE BASE

PACIFICORP

Miscellaneous Rate Base (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1140000	EL PLT ACQUIST ADJ	1140000	ELECTRIC PLANT ACQUISITION ADJUSTMENTS	SG	144,705	2,006	40,164	10,615	19,252	64,519	8,143	6	-
1140000	EL PLT ACQUIST ADJ	1140000	ELECTRIC PLANT ACQUISITION ADJUSTMENTS	UT	11,764	-	-	-	-	11,764	-	-	-
1140000 Total					**156,468**	**2,006**	**40,164**	**10,615**	**19,252**	**76,283**	**8,143**	**6**	**-**
1150000	Ac Prov El Pt Acq Ad	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	SG	(142,164)	(1,971)	(39,458)	(10,429)	(18,914)	(63,386)	(8,000)	(6)	-
1150000	Ac Prov El Pt Acq Ad	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	UT	(3,104)	-	-	-	-	(3,104)	-	-	-
1150000 Total					**(145,268)**	**(1,971)**	**(39,458)**	**(10,429)**	**(18,914)**	**(66,490)**	**(8,000)**	**(6)**	**-**
1281000	Oth Special Funds-Pn	0	Other special funds - Pensions	SO	158,341	4,801	44,191	11,114	19,238	70,479	8,514	4	-
1281000 Total					**158,341**	**4,801**	**44,191**	**11,114**	**19,238**	**70,479**	**8,514**	**4**	**-**
1651000	PREPAY-INSURANCE	132008	PREPAID INSURANCE - PUBLIC LIABILITY & P	SO	115,580	3,504	32,257	8,112	14,043	51,446	6,214	3	-
1651000	PREPAY-INSURANCE	132012	PREPAID INSURANCE - ALLPURPOSE INSURANC	SO	3,273	99	913	230	398	1,457	176	0	-
1651000	PREPAY-INSURANCE	132016	PREPAID INS-MINORITY OWNED PLANTS	SO	533	16	149	37	65	237	29	0	-
1651000	PREPAY-INSURANCE	132045	PREPAID WORKERS COMPENSATION	SO	392	12	109	27	48	174	21	0	-
1651000	PREPAY-INSURANCE	132055	PREPAID EMPLOYEE BENEFIT COSTS	SO	64	2	18	4	8	28	3	0	-
1651000 Total					**119,842**	**3,634**	**33,447**	**8,411**	**14,560**	**53,343**	**6,444**	**3**	**-**
1652000	PREPAY-TAXES	132109	UTE-PREPAID POSSESSORY INTEREST	GPS	6	0	2	0	1	3	0	0	-
1652000	PREPAY-TAXES	132110	SHO-BAN-PREPAID POSSESSORY INTEREST	GPS	60	2	17	4	7	27	3	0	-
1652000	PREPAY-TAXES	132111	Goshute - Prepaid Possessory Interest	GPS	14	0	4	1	2	6	1	0	-
1652000 Total					**80**	**3**	**22**	**6**	**10**	**36**	**4**	**0**	**-**
1652100	PREPAY - OTHER	0	1652100/0	OTHER	991	-	-	-	-	-	-	-	991
1652100	PREPAY - OTHER	132098	Prepaid - CA GHG Wholesale	OTHER	(991)	-	-	-	-	-	-	-	(991)
1652100	PREPAY - OTHER	132548	Prepaid-FSA O&M - Cedar Springs II	SG	538	7	149	39	72	240	30	0	-
1652100	PREPAY - OTHER	132551	Prepaid-FSA O&M - Dunlap	SG	347	5	96	25	46	155	19	0	-
1652100	PREPAY - OTHER	132557	Prepaid-FSA O&M - Glenrock I	SG	464	6	129	34	62	207	26	0	-
1652100	PREPAY - OTHER	132558	Prepaid-FSA O&M - Glenrock III	SG	304	4	84	22	40	136	17	0	-
1652100	PREPAY - OTHER	132561	Prepaid-FSA O&M - Goodnoe Hills	SG	393	5	109	29	52	175	22	0	-
1652100	PREPAY - OTHER	132564	Prepaid-FSA O&M - High Plains	SG	927	13	257	68	123	413	52	0	-
1652100	PREPAY - OTHER	132567	Prepaid-FSA O&M - Leaning Juniper	SG	314	4	87	23	42	140	18	0	-
1652100	PREPAY - OTHER	132570	Prepaid-FSA O&M - Marengo I	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
1652100	PREPAY - OTHER	132571	Prepaid-FSA O&M - Marengo II	SG	0	0	0	0	0	0	0	0	-
1652100	PREPAY - OTHER	132574	Prepaid-FSA O&M - McFadden Ridge	SG	222	3	62	16	30	99	13	0	-
1652100	PREPAY - OTHER	132576	Prepaid-FSA O&M - Pryor Mtn	SG	0	0	0	0	0	0	0	0	-
1652100	PREPAY - OTHER	132577	Prepaid-FSA O&M - Rolling Hills	SG	464	6	129	34	62	207	26	0	-
1652100	PREPAY - OTHER	132580	Prepaid-FSA O&M - Seven Mile I	SG	309	4	86	23	41	138	17	0	-
1652100	PREPAY - OTHER	132581	Prepaid-FSA O&M - Seven Mile II	SG	61	1	17	4	8	27	3	0	-
1652100	PREPAY - OTHER	132584	Prepaid-FSA O&M - TB Flats I	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
1652100	PREPAY - OTHER	132585	Prepaid-FSA O&M - TB Flats II	SG	0	0	0	0	0	0	0	0	-
1652100	PREPAY - OTHER	132586	Prepaid-FSA O&M - Rock River	SG	214	3	59	16	28	95	12	0	-
1652100	PREPAY - OTHER	132620	PREPAYMENTS - WATER RIGHTS LEASE	SG	598	8	166	44	80	267	34	0	-
1652100	PREPAY - OTHER	132621	Prepayments - Water Rights (Ferron Canal	SG	223	3	62	16	30	99	13	0	-
1652100	PREPAY - OTHER	132622	Prepayments - Water Rights (Hntgtn-Clev)	SG	291	4	81	21	39	130	16	0	-
1652100	PREPAY - OTHER	132650	PREPAID DUES	SO	4,256	129	1,188	299	517	1,894	229	0	-
1652100	PREPAY - OTHER	132705	Prepaid Pole Contact	SG	53	1	15	4	7	24	3	0	-
1652100	PREPAY - OTHER	132740	PREPAID O&M WIND	SG	79	1	22	6	11	35	4	0	-
1652100	PREPAY - OTHER	132755	Prepaid Aircraft Maintenance Costs	SG	71	1	20	5	9	32	4	0	-
1652100	PREPAY - OTHER	132825	Prepaid LGIA Transmission	SG	791	11	220	58	105	353	45	0	-
1652100	PREPAY - OTHER	132900	PREPAYMENTS - OTHER	SE	72	1	19	5	10	32	4	0	-
1652100	PREPAY - OTHER	132900	PREPAYMENTS - OTHER	SO	4,497	136	1,255	316	546	2,002	242	0	-
1652100	PREPAY - OTHER	132901	PRE FEES - OREGON PUB UTIL COMMISSION	OR	6,167	-	6,167	-	-	-	-	-	-
1652100	PREPAY - OTHER	132903	PREP FEES-UTAH PUBLIC SERVICE COMMISSION	UT	7,258	-	-	-	-	7,258	-	-	-
1652100	PREPAY - OTHER	132904	PREP FEES-IDAHO PUB UTIL COMMISSION	IDU	393	-	-	-	-	-	393	-	-
1652100	PREPAY - OTHER	132910	Prepayments - Hardware & Software	SO	25,226	765	7,040	1,771	3,065	11,228	1,356	1	-
1652100	PREPAY - OTHER	132998	PREPAID INSURANCE	SE	(161)	(2)	(43)	(11)	(23)	(72)	(10)	(0)	-
1652100	PREPAY - OTHER	132999	PREPAY - RECLASS TO LT	SO	(1,454)	(44)	(406)	(102)	(177)	(647)	(78)	(0)	-
1652100	PREPAY - OTHER	134000	L/T PREPAY RECLASS	SO	1,615	49	451	113	196	719	87	0	-
1652100	PREPAY - OTHER	185363	LT Prepayments - Other	SO	250	8	70	18	30	111	13	0	-
1652100 Total					**54,781**	**1,134**	**17,590**	**2,896**	**5,052**	**25,496**	**2,612**	**1**	**-**
2281000	ACC PROV-PROP INS	288711	Reg Liab - CA Property Insurance Reserve	CA	4,551	4,551	-	-	-	-	-	-	-
2281000	ACC PROV-PROP INS	288712	Reg Liab - OR Property Insurance Reserve	OR	48,748	-	48,748	-	-	-	-	-	-
2281000	ACC PROV-PROP INS	288713	Reg Liab - WA Property Insurance Reserve	WA	(268)	-	-	(268)	-	-	-	-	-
2281000	ACC PROV-PROP INS	288714	Reg Liab - ID Property Insurance Reserve	IDU	(660)	-	-	-	-	-	(660)	-	-
2281000	ACC PROV-PROP INS	288715	Reg Liab - UT Property Insurance Reserve	UT	1,747	-	-	-	-	1,747	-	-	-
2281000	ACC PROV-PROP INS	288716	Reg Liab - WY Property Insurance Reserve	WYP	(382)	-	-	-	(382)	-	-	-	-

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Miscellaneous Rate Base (Actuals)
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Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2281000	ACC PROV-PROP INS	288746	RegL - Insurance Reserves-Recl to Asst	OTHER	(1,747)	-	-	-	-	-	-	-	(1,747)
2281000	ACC PROV-PROP INS	288747	RegL-CA Insurance Reserves-Recl to Asst	OTHER	(4,551)	-	-	-	-	-	-	-	(4,551)
2281000	ACC PROV-PROP INS	288749	RegL - Insurance Reserves - Reclass	OTHER	(48,748)	-	-	-	-	-	-	-	(48,748)
2281000 Total					**(1,310)**	**4,551**	**48,748**	**(268)**	**(382)**	**1,747**	**(660)**	**-**	**(55,046)**
2281200	ACC PRV-INS-T&D LN	280299	Accum Prov for Prop Ins - PP-Rec to Cur	OTHER	2,029	-	-	-	-	-	-	-	2,029
2281200	ACC PRV-INS-T&D LN	280307	Accum Prov For Prop Ins - Pac Power T&D	SO	(2,029)	(62)	(566)	(142)	(246)	(903)	(109)	(0)	-
2281200 Total					**-**	**(62)**	**(566)**	**(142)**	**(246)**	**(903)**	**(109)**	**(0)**	**2,029**
2282100	ACC PRV IN & DAMAG	280310	PROVISION FOR INJURIES & DAMAGES: CLAIMS	SO	(8,903)	(270)	(2,485)	(625)	(1,082)	(3,963)	(479)	(0)	-
2282100	ACC PRV IN & DAMAG	280311	CATASTROPHIC WILDFIRE CLAIMS	SO	(1,380,943)	(41,870)	(385,406)	(96,925)	(167,781)	(614,672)	(74,249)	(39)	-
2282100	ACC PRV IN & DAMAG	280312	Provision for Injuries & Damages - Other	SO	(530)	(16)	(148)	(37)	(64)	(236)	(28)	(0)	-
2282100	ACC PRV IN & DAMAG	280314	I & D Provisions - Reclass to Current	SO	9,433	286	2,633	662	1,146	4,199	507	0	-
2282100	ACC PRV IN & DAMAG	280420	I&D Prov Catastrophic WF Claims Rec Cur	OTHER	506,680	-	-	-	-	-	-	-	506,680
2282100 Total					**(874,263)**	**(41,870)**	**(385,406)**	**(96,925)**	**(167,781)**	**(614,672)**	**(74,249)**	**(39)**	**506,680**
2282400	ACCUM PRV FR I&D-OR	288700	Reg Liab - OR Injuries & Damages Reserve	OR	3,443	-	3,443	-	-	-	-	-	-
2282400	ACCUM PRV FR I&D-OR	288745	RegL - Injuries & Damages-Recl to Asst	OTHER	(3,443)	-	-	-	-	-	-	-	(3,443)
2282400 Total					**-**	**-**	**3,443**	**-**	**-**	**-**	**-**	**-**	**(3,443)**
2283000	PEN/BENFT-SICK	280349	SUPPL. PENSION BENEFITS (RETIRE ALLOW)	SO	(916)	(28)	(256)	(64)	(111)	(408)	(49)	(0)	-
2283000 Total					**(916)**	**(28)**	**(256)**	**(64)**	**(111)**	**(408)**	**(49)**	**(0)**	**-**
2283500	PENSIONS	280365	FAS 158 Pension Liab-Rcls to Current	SO	163	5	46	11	20	73	9	0	-
2283500 Total					**163**	**5**	**46**	**11**	**20**	**73**	**9**	**0**	**-**
2284100	AC MIS OP PR-OTHER	289320	CHEHALIS WA EFSEC C02 MITIGATION OBLIG	SG	(235)	(3)	(65)	(17)	(31)	(105)	(13)	(0)	-
2284100 Total					**(235)**	**(3)**	**(65)**	**(17)**	**(31)**	**(105)**	**(13)**	**(0)**	**-**
2300000	ASSET RETIREMENT OB	284918	ARO LIAB - TROJAN NUCLEAR PLANT	TROJD	(7,998)	(109)	(2,207)	(578)	(1,079)	(3,570)	(456)	(0)	-
2300000 Total					**(7,998)**	**(109)**	**(2,207)**	**(578)**	**(1,079)**	**(3,570)**	**(456)**	**(0)**	**-**
2530000	OTHER DEF CREDITS	248156	Deferred Income - CIAC Tax Gross Up	SG	(5,279)	(73)	(1,465)	(387)	(702)	(2,354)	(297)	(0)	-
2530000	OTHER DEF CREDITS	248156	Deferred Income - CIAC Tax Gross Up	UT	(78)	-	-	-	-	(78)	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENU	CA	(157)	(157)	-	-	-	-	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENU	IDU	(15)	-	-	-	-	-	(15)	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENU	OR	(149)	-	(149)	-	-	-	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENU	UT	(188)	-	-	-	-	(188)	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENU	WA	(271)	-	-	(271)	-	-	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENU	WYP	(31)	-	-	-	(31)	-	-	-	-
2530000 Total					**(6,169)**	**(230)**	**(1,615)**	**(659)**	**(733)**	**(2,620)**	**(313)**	**(0)**	**-**
2533500	OTH DEF CR-PEN & BEN	280370	PENSION LIAB-UMWA WITHDRAWAL OBLIG	SE	(79,857)	(998)	(21,420)	(5,357)	(11,452)	(35,819)	(4,806)	(4)	-
2533500 Total					**(79,857)**	**(998)**	**(21,420)**	**(5,357)**	**(11,452)**	**(35,819)**	**(4,806)**	**(4)**	**-**
2539900	OTH DEF CR - OTHER	0	Fossil Rock Fuels Entries	SE	(5,006)	(63)	(1,343)	(336)	(718)	(2,246)	(301)	(0)	-
2539900	OTH DEF CR - OTHER	230155	EMPLOYEE HOUSING SECURITY DEPOSITS	CA	(21)	(21)	-	-	-	-	-	-	-
2539900	OTH DEF CR - OTHER	284902	IT Software Licenses	SO	(51,615)	(1,565)	(14,405)	(3,623)	(6,271)	(22,974)	(2,775)	(1)	-
2539900	OTH DEF CR - OTHER	289051	DEFERRED RENT REVENUE AMORT OIL & GAS L	SG	(1,135)	(16)	(315)	(83)	(151)	(506)	(64)	(0)	-
2539900	OTH DEF CR - OTHER	289341	Accrued Royalties-Reg Rcvry-Noncurrent	SE	(1,060)	(13)	(284)	(71)	(152)	(475)	(64)	(0)	-
2539900	OTH DEF CR - OTHER	289396	Accrued Royalties - Reclass to Current	OTHER	1,060	-	-	-	-	-	-	-	1,060
2539900	OTH DEF CR - OTHER	289523	Govt Coal Lease Bonus Payment Liability	SE	5,006	63	1,343	336	718	2,246	301	0	-
2539900	OTH DEF CR - OTHER	289913	MCI - F.O.G. WIRE LEASE	SG	(498)	(7)	(138)	(37)	(66)	(222)	(28)	(0)	-
2539900	OTH DEF CR - OTHER	289914	TRANSMISSION SERVICE DEPOSITS - THIRD PA	SG	(1,908)	(26)	(529)	(140)	(254)	(851)	(107)	(0)	-
2539900	OTH DEF CR - OTHER	289923	Transmission Cluster Study Deposits	SG	(37,218)	(516)	(10,330)	(2,730)	(4,952)	(16,594)	(2,094)	(2)	-
2539900	OTH DEF CR - OTHER	289925	TRANSM CONST SECURITY DEPOSITS	SG	(31,697)	(439)	(8,798)	(2,325)	(4,217)	(14,133)	(1,784)	(1)	-
2539900	OTH DEF CR - OTHER	289927	Transm Deposit - Readiness Fin Security	SG	(105,092)	(1,457)	(29,169)	(7,709)	(13,982)	(46,857)	(5,914)	(4)	-
2539900	OTH DEF CR - OTHER	289928	Transmission Deposits-Site Control	SG	(1,060)	(15)	(294)	(78)	(141)	(473)	(60)	(0)	-
2539900	OTH DEF CR - OTHER	289955	Accrued Right-of-Way Obligations	SG	(2,410)	(33)	(669)	(177)	(321)	(1,074)	(136)	(0)	-
2539900 Total					**(232,652)**	**(4,108)**	**(64,931)**	**(16,972)**	**(30,507)**	**(104,159)**	**(13,025)**	**(9)**	**1,060**
2540000	REGULATORY LIAB	231010	Reg Liab Current - Blue Sky	OTHER	(6,919)	-	-	-	-	-	-	-	(6,919)
2540000	REGULATORY LIAB	231020	Reg Liab Current - DSM	OTHER	(7,465)	-	-	-	-	-	-	-	(7,465)
2540000	REGULATORY LIAB	231045	Reg Liab Current - GHG Allowances	OTHER	(5,363)	-	-	-	-	-	-	-	(5,363)
2540000	REGULATORY LIAB	231060	Reg Liab Current - BPA Balancing Accts	OTHER	(2,827)	-	-	-	-	-	-	-	(2,827)
2540000	REGULATORY LIAB	231080	Reg Liab Current - REC Sales	OTHER	(10,893)	-	-	-	-	-	-	-	(10,893)
2540000	REGULATORY LIAB	231095	Reg Liab Current - Income Tax Related	OTHER	(2,221)	-	-	-	-	-	-	-	(2,221)
2540000	REGULATORY LIAB	231096	Reg Liab Current - Exc Def Inc Tax	OTHER	(5,456)	-	-	-	-	-	-	-	(5,456)
2540000	REGULATORY LIAB	231097	Reg Liab Current - Trans Rate True-Up	OTHER	(16,942)	-	-	-	-	-	-	-	(16,942)
2540000	REGULATORY LIAB	231100	Reg Liab Current - Other	OTHER	(25,730)	-	-	-	-	-	-	-	(25,730)
2540000	REGULATORY LIAB	288005	Reg Liab - Excess Def Inc Taxes - WA	WA	(170)	-	-	(170)	-	-	-	-	-
2540000	REGULATORY LIAB	288021	Reg Liab-FAS 158 Post-Retirement	SO	(51,543)	(1,563)	(14,385)	(3,618)	(6,262)	(22,942)	(2,771)	(1)	-
2540000	REGULATORY LIAB	288063	Reg L-WA Decoupling Mech Jan23-Dec23	OTHER	(1,109)	-	-	-	-	-	-	-	(1,109)

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Miscellaneous Rate Base (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2540000	REGULATORY LIAB	288064	Reg L-WA Decoupling Mech Jan24-Dec24	OTHER	6,488	-	-	-	-	-	-	-	6,488
2540000	REGULATORY LIAB	288065	Reg L-WA Decoupling Mech Jan25-Dec25	OTHER	3,314	-	-	-	-	-	-	-	3,314
2540000	REGULATORY LIAB	288075	Contra Reg L-WA Decoupling Jan25-Dec25	OTHER	(166)	-	-	-	-	-	-	-	(166)
2540000	REGULATORY LIAB	288079	RegL-WA Decoupling Mech - Recl to Curr	OTHER	1,109	-	-	-	-	-	-	-	1,109
2540000	REGULATORY LIAB	288081	Reg Liab - Cholla Decomm - CA	CA	155	155	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288082	Reg Liab - Cholla Decomm - ID	IDU	(925)	-	-	-	-	-	(925)	-	-
2540000	REGULATORY LIAB	288083	Reg Liab - Cholla Decomm - OR	OR	(1,344)	-	(1,344)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288084	Reg Liab - Cholla Decomm - UT	UT	(7,188)	-	-	-	-	(7,188)	-	-	-
2540000	REGULATORY LIAB	288086	Reg Liab - Cholla Decomm - WY	WYP	1,937	-	-	-	1,937	-	-	-	-
2540000	REGULATORY LIAB	288096	Reg Liab-OR-Other Plnt Closure Cost Def	OR	(673)	-	(673)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288097	Reg Liab-CA-Plant Closure Cost Deferral	CA	(952)	(952)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288099	RegL-Depr/Amortz Deferral-Bal Reclass	OTHER	(2,092)	-	-	-	-	-	-	-	(2,092)
2540000	REGULATORY LIAB	288114	REG LIABILITY - OR GAIN-SALE EPUD ASSETS	OTHER	1	-	-	-	-	-	-	-	1
2540000	REGULATORY LIAB	288159	RegL - Blue Sky - Recl to Curr	OTHER	6,919	-	-	-	-	-	-	-	6,919
2540000	REGULATORY LIAB	288161	RL-Energy Savings Assistance (ESA)-CA	OTHER	(619)	-	-	-	-	-	-	-	(619)
2540000	REGULATORY LIAB	288162	Reg Liab-CA Klamath River Dams Removal	CA	(260)	(260)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288165	Reg Liab - OR Enrgy	OTHER	(8,882)	-	-	-	-	-	-	-	(8,882)
2540000	REGULATORY LIAB	288191	RegL - OR Pryor Mtn REC	OTHER	(106)	-	-	-	-	-	-	-	(106)
2540000	REGULATORY LIAB	288214	Reg Liab - Non-Prot PP&E EDIT - WA	WA	(3,351)	-	-	(3,351)	-	-	-	-	-
2540000	REGULATORY LIAB	288260	Reg Liability - WA PCAM CY2021	OTHER	4,705	-	-	-	-	-	-	-	4,705
2540000	REGULATORY LIAB	288262	Reg Liability - WA PCAM CY2022	OTHER	54,863	-	-	-	-	-	-	-	54,863
2540000	REGULATORY LIAB	288264	Reg Liability - WA PCAM PTC CY2021	OTHER	(2,562)	-	-	-	-	-	-	-	(2,562)
2540000	REGULATORY LIAB	288285	Reg Liab-Excess Income Tax Deferral-WA	OTHER	(2,088)	-	-	-	-	-	-	-	(2,088)
2540000	REGULATORY LIAB	288295	RegL - BPA Balancing Accts - Recl to Cur	OTHER	2,827	-	-	-	-	-	-	-	2,827
2540000	REGULATORY LIAB	288402	RegL-OR Sch 291 Standard Rate-Clearing	OTHER	0	-	-	-	-	-	-	-	0
2540000	REGULATORY LIAB	288405	Reg Liab-OR Direct Access 5 yr Opt Out	OTHER	(1,068)	-	-	-	-	-	-	-	(1,068)
2540000	REGULATORY LIAB	288406	Reg L-OR-Bridger Mine Accel Depr&Reclm	OR	(16,458)	-	(16,458)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288409	Reg Liab-WA-Plant Closure Cost Deferral	WA	(6,101)	-	-	(6,101)	-	-	-	-	-
2540000	REGULATORY LIAB	288410	Reg Liab-WA-Bridger Mine Accel Depr	WA	(10,768)	-	-	(10,768)	-	-	-	-	-
2540000	REGULATORY LIAB	288420	Reg Liab - CA GHG Allowance Revenues	OTHER	8,513	-	-	-	-	-	-	-	8,513
2540000	REGULATORY LIAB	288422	Reg Liab - CA Solar (SOMAH)-GHG Funds	OTHER	(11,292)	-	-	-	-	-	-	-	(11,292)
2540000	REGULATORY LIAB	288423	RegL - CA GHG Allowances - Recl to Curr	OTHER	5,363	-	-	-	-	-	-	-	5,363
2540000	REGULATORY LIAB	288424	RegL - CA GHG Allowances - Balance Recl	OTHER	(13,876)	-	-	-	-	-	-	-	(13,876)
2540000	REGULATORY LIAB	288443	RegL - OR RECs in Rates - Recl to Curr	OTHER	8,853	-	-	-	-	-	-	-	8,853
2540000	REGULATORY LIAB	288444	RegL - UT RECs in Rates - Recl to Curr	OTHER	1,533	-	-	-	-	-	-	-	1,533
2540000	REGULATORY LIAB	288446	RegL - WY RECs in Rates - Recl to Curr	OTHER	508	-	-	-	-	-	-	-	508
2540000	REGULATORY LIAB	288450	Reg Liab - WA Fly Ash	OTHER	(1,670)	-	-	-	-	-	-	-	(1,670)
2540000	REGULATORY LIAB	288453	RegL - OR RECs in Rates - Balance Recl	OTHER	(1,143)	-	-	-	-	-	-	-	(1,143)
2540000	REGULATORY LIAB	288454	RegL - UT RECs in Rates - Balance Recl	OTHER	(6,121)	-	-	-	-	-	-	-	(6,121)
2540000	REGULATORY LIAB	288456	RegL - WY RECs in Rates - Balance Recl	OTHER	(1,228)	-	-	-	-	-	-	-	(1,228)
2540000	REGULATORY LIAB	288470	Reg L-WA Decoupling Mechanism-Reclass	OTHER	(9,637)	-	-	-	-	-	-	-	(9,637)
2540000	REGULATORY LIAB	288475	RegL - WA Def Exc NPC - Balance Reclass	OTHER	(57,006)	-	-	-	-	-	-	-	(57,006)
2540000	REGULATORY LIAB	288817	RegL - DSM - CA - Reclass to Current	OTHER	1,008	-	-	-	-	-	-	-	1,008
2540000	REGULATORY LIAB	288819	Reg Liab - DSM - CA - Balance Reclass	OTHER	(1,008)	-	-	-	-	-	-	-	(1,008)
2540000	REGULATORY LIAB	288827	RegL - DSM - ID - Reclass to Current	OTHER	4,890	-	-	-	-	-	-	-	4,890
2540000	REGULATORY LIAB	288829	Reg Liab - DSM - ID - Balance Reclass	OTHER	(4,890)	-	-	-	-	-	-	-	(4,890)
2540000	REGULATORY LIAB	288837	RegL - DSM - OR - Reclass to Current	OTHER	1,567	-	-	-	-	-	-	-	1,567
2540000	REGULATORY LIAB	288839	Reg Liab - DSM - OR - Balance Reclass	OTHER	(1,567)	-	-	-	-	-	-	-	(1,567)
2540000	REGULATORY LIAB	288931	Reg Liab - Protected PP&E EDIT - CA	CA	(27,757)	(27,757)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288932	Reg Liab - Protected PP&E EDIT - ID	IDU	(70,920)	-	-	-	-	-	(70,920)	-	-
2540000	REGULATORY LIAB	288933	Reg Liab - Protected PP&E EDIT - OR	OR	(307,899)	-	(307,899)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288934	Reg Liab - Protected PP&E EDIT - WA	WA	(65,038)	-	-	(65,038)	-	-	-	-	-
2540000	REGULATORY LIAB	288935	Reg Liab - Protected PP&E EDIT - WY	WYP	(174,106)	-	-	-	(174,106)	-	-	-	-
2540000	REGULATORY LIAB	288936	Reg Liab - Protected PP&E EDIT - UT	UT	(551,146)	-	-	-	-	(551,146)	-	-	-
2540000	REGULATORY LIAB	288943	Reg Liab - Protected PP&E ARAM - OR	OR	(2)	-	(2)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288945	Reg Liab - Protected PP&E ARAM - WA	WA	(2,041)	-	-	(2,041)	-	-	-	-	-
2540000	REGULATORY LIAB	288947	RegL-Exc Def Inc Tax-Recl to Curr	OTHER	5,456	-	-	-	-	-	-	-	5,456
2540000	REGULATORY LIAB	288948	RegL-Income Tax Related-Recl to Asset	OTHER	(133)	-	-	-	-	-	-	-	(133)
2540000	REGULATORY LIAB	288949	RegL - EDIT Deferral - Recl to Curr	OTHER	2,221	-	-	-	-	-	-	-	2,221
2540000	REGULATORY LIAB	288951	Reg Liab - Pension Settlement - UT	OTHER	(4,589)	-	-	-	-	-	-	-	(4,589)
2540000	REGULATORY LIAB	288953	RegL Trans Rate True-Up - Recl to Curr	OTHER	16,942	-	-	-	-	-	-	-	16,942
2540000	REGULATORY LIAB	288995	RegL - Other - Recl to Curr	OTHER	24,621	-	-	-	-	-	-	-	24,621

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Miscellaneous Rate Base (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2540000 Total					(1,351,515)	(30,376)	(340,761)	(91,086)	(178,431)	(581,276)	(74,616)	(1)	(54,968)
Grand Total					(2,210,508)	(63,621)	(669,035)	(189,444)	(351,537)	(1,182,567)	(150,572)	(44)	396,311

B16. REGULATORY ASSETS

PACIFICORP

Regulatory Assests (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-UPL + Wy-PPL	Utah	Id-PPL + Idaho	FERC	Other
1242000	PAC PWR-INT FREE LN	0	INT FREE-PPL	OTHER	629	-	-	-	-	-	-	-	629
1242000	PAC PWR-INT FREE LN	0	INT FREE-PPL	WA	7	-	-	7	-	-	-	-	-
1242000 Total					**636**	**-**	**-**	**7**	**-**	**-**	**-**	**-**	**629**
1247100	CSS/ELI SYSTEM LOANS	0	CSS/ELI SYSTEM	OTHER	4	-	-	-	-	-	-	-	4
1247100 Total					**4**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**4**
1249000	RESV UNCOLL ESC&WZ	0	ESC - RESERVE	OTHER	(171)	-	-	-	-	-	-	-	(171)
1249000	RESV UNCOLL ESC&WZ	0	ESC - RESERVE	UT	0	-	-	-	-	0	-	-	-
1249000	RESV UNCOLL ESC&WZ	0	ESC - RESERVE	WA	(4)	-	-	(4)	-	-	-	-	-
1249000 Total					**(175)**	**-**	**-**	**(4)**	**-**	**0**	**-**	**-**	**(171)**
1823000	DSR REGULATORY ASSET	0	DSR REGULATORY ASSETS	OTHER	(225,211)	-	-	-	-	-	-	-	(225,211)
1823000 Total					**(225,211)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(225,211)**
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	CA	166	166	-	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	OR	752	-	752	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	SE	(1,662)	(21)	(446)	(111)	(238)	(745)	(100)	(0)	-
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	WA	744	-	-	744	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186820	Reg Asset-Deer Creek Mine ARO	SE	6,915	86	1,855	464	992	3,101	416	0	-
1823700	OTH REGA-ENERGY WEST	186825	Reg Asset-Deer Creek Mine M&S	SE	4,492	56	1,205	301	644	2,015	270	0	-
1823700	OTH REGA-ENERGY WEST	186826	Reg Asset-Deer Creek-Prepaid Royalties	SE	843	11	226	57	121	378	51	0	-
1823700	OTH REGA-ENERGY WEST	186828	Reg Asset-Deer Creek-Recovery Royalties	SE	16,227	203	4,353	1,089	2,327	7,279	977	1	-
1823700	OTH REGA-ENERGY WEST	186829	Contra RA-DCM Closure-Royalties Amortz	IDU	(1,041)	-	-	-	-	-	(1,041)	-	-
1823700	OTH REGA-ENERGY WEST	186829	Contra RA-DCM Closure-Royalties Amortz	OR	(693)	-	(693)	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186829	Contra RA-DCM Closure-Royalties Amortz	UT	(565)	-	-	-	-	(565)	-	-	-
1823700	OTH REGA-ENERGY WEST	186829	Contra RA-DCM Closure-Royalties Amortz	WYU	(2,929)	-	-	-	(2,929)	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186830	Reg Asset-Deer Creek-Union Suppl Ben	SE	1,612	20	432	108	231	723	97	0	-
1823700	OTH REGA-ENERGY WEST	186833	Reg Asset-Deer Creek-Nonunion Severance	SE	2,770	35	743	186	397	1,243	167	0	-
1823700	OTH REGA-ENERGY WEST	186835	Reg Asset-Deer Creek-Misc Closure Costs	SE	45,112	564	12,100	3,026	6,469	20,235	2,715	2	-
1823700	OTH REGA-ENERGY WEST	186836	Contra RA-DCM Closure-To Joint Owners	SE	(3,219)	(40)	(863)	(216)	(462)	(1,444)	(194)	(0)	-
1823700	OTH REGA-ENERGY WEST	186837	Contra RA-DCM Closure-Amortz & Oth Adjs	IDU	(3,791)	-	-	-	-	-	(3,791)	-	-
1823700	OTH REGA-ENERGY WEST	186837	Contra RA-DCM Closure-Amortz & Oth Adjs	OTHER	(14,361)	-	-	-	-	-	-	-	(14,361)
1823700	OTH REGA-ENERGY WEST	186837	Contra RA-DCM Closure-Amortz & Oth Adjs	UT	(26,234)	-	-	-	-	(26,234)	-	-	-
1823700	OTH REGA-ENERGY WEST	186837	Contra RA-DCM Closure-Amortz & Oth Adjs	WYU	(10,671)	-	-	-	(10,671)	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186839	Reg Asset-Deer Creek-Tax Flow-Through	SE	2,979	37	799	200	427	1,336	179	0	-
1823700	OTH REGA-ENERGY WEST	186851	Contra Reg Asset-Deer Creek Closure-CA	CA	(1,292)	(1,292)	-	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186855	Contra Reg Asset-Deer Creek Closure-WA	WA	(4,561)	-	-	(4,561)	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186861	RA-Deer Creek-ROR Offset-Fuel Inventory	IDU	(1,669)	-	-	-	-	-	(1,669)	-	-
1823700	OTH REGA-ENERGY WEST	186861	RA-Deer Creek-ROR Offset-Fuel Inventory	UT	(8,931)	-	-	-	-	(8,931)	-	-	-
1823700	OTH REGA-ENERGY WEST	186861	RA-Deer Creek-ROR Offset-Fuel Inventory	WYU	(419)	-	-	-	(419)	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186863	RA-Deer Creek-ROR Offset-Note Intrst-ID	IDU	(191)	-	-	-	-	-	(191)	-	-
1823700	OTH REGA-ENERGY WEST	186871	RA-DC ROR Offset-Fuel Inventory-Amortz	IDU	1,669	-	-	-	-	-	1,669	-	-
1823700	OTH REGA-ENERGY WEST	186871	RA-DC ROR Offset-Fuel Inventory-Amortz	UT	8,931	-	-	-	-	8,931	-	-	-
1823700	OTH REGA-ENERGY WEST	186871	RA-DC ROR Offset-Fuel Inventory-Amortz	WYP	419	-	-	-	419	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186873	RA-DC ROR Offset-Note Interest-Amortz	IDU	191	-	-	-	-	-	191	-	-
1823700	OTH REGA-ENERGY WEST	186881	Reg Asset-UMWA Pension Trust Oblig	SE	79,857	998	21,420	5,357	11,452	35,819	4,806	4	-
1823700	OTH REGA-ENERGY WEST	186886	Contra RA-UMWA Pens W/D-To Joint Owners	OTHER	(3,297)	-	-	-	-	-	-	-	(3,297)
1823700	OTH REGA-ENERGY WEST	186895	Contra Reg Asset-UMWA Pension Trust-WA	OTHER	(5,617)	-	-	-	-	-	-	-	(5,617)
1823700 Total					**82,537**	**824**	**41,883**	**6,642**	**8,761**	**43,141**	**4,552**	**8**	**(23,274)**
1823750	OTHER REG A-CHLA U4	185831	Reg Asset - Cholla Unrec Plant - CA	CA	2,360	2,360	-	-	-	-	-	-	-
1823750	OTHER REG A-CHLA U4	185836	Reg Asset - Cholla Unrec Plant - WY	WYP	26,669	-	-	-	26,669	-	-	-	-
1823750	OTHER REG A-CHLA U4	185864	Reg Asset-Cholla U4-Property Taxes-OR	OTHER	187	-	-	-	-	-	-	-	187
1823750	OTHER REG A-CHLA U4	185866	Reg Asset-Cholla U4-Nonunion Severance	SG	532	7	148	39	71	237	30	0	-
1823750	OTHER REG A-CHLA U4	185867	Reg Asset-Cholla U4-Safe Harbor Lease	SG	29	0	8	2	4	13	2	0	-
1823750 Total					**29,777**	**2,368**	**156**	**41**	**26,744**	**250**	**32**	**0**	**187**
1823870	DEFERRED PENSION	187017	FAS 158 Pen Liab Adj	SO	243,479	7,382	67,952	17,089	29,582	108,375	13,091	7	-
1823870	DEFERRED PENSION	187608	Reg Asset - Pension Settlement - CA	OTHER	1,266	-	-	-	-	-	-	-	1,266
1823870	DEFERRED PENSION	187611	Reg Asset - Pension Settlement - OR	OTHER	9,582	-	-	-	-	-	-	-	9,582
1823870	DEFERRED PENSION	187613	Reg Asset - Pension Settlement - WY	WYU	4,425	-	-	-	4,425	-	-	-	-
1823870	DEFERRED PENSION	187621	Reg Asset FAS - 158	SO	(51,543)	(1,563)	(14,385)	(3,618)	(6,262)	(22,942)	(2,771)	(1)	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	CA	(127)	(127)	-	-	-	-	-	-	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	IDU	(521)	-	-	-	-	-	(521)	-	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	OTHER	(2,036)	-	-	-	-	-	-	-	(2,036)
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	SO	8,323	252	2,323	584	1,011	3,705	448	0	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	UT	(3,566)	-	-	-	-	(3,566)	-	-	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	WA	(660)	-	-	(660)	-	-	-	-	-

PACIFICORP

Regulatory Assests (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-UPL + Wy-PPL	Utah	Id-PPL + Idaho	FERC	Other
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	WYU	(1,412)	-	-	-	(1,412)	-	-	-	-
1823870	DEFERRED PENSION	187649	Reg Asset-FAS 158 Post-Ret - Reclass	SO	51,543	1,563	14,385	3,618	6,262	22,942	2,771	1	-
1823870 Total					**258,752**	**7,508**	**70,275**	**17,013**	**33,606**	**108,514**	**13,018**	**7**	**8,811**
1823910	ENVIR CST UNDR AMORT	102465	UTAH METALS CLEANUP	SO	62	2	17	4	8	28	3	0	-
1823910	ENVIR CST UNDR AMORT	103408	D-SM RETAIL MINOR SITES	SO	3,521	107	983	247	428	1,567	189	0	-
1823910	ENVIR CST UNDR AMORT	103420	ASTORIA YOUNGS BAY CLEANUP	SO	374	11	104	26	45	166	20	0	-
1823910	ENVIR CST UNDR AMORT	103426	SILVER BELL MINE ENVIRONMENTAL REMED	SO	5,726	174	1,598	402	696	2,549	308	0	-
1823910	ENVIR CST UNDR AMORT	103445	American Barrel (UT)	SO	155	5	43	11	19	69	8	0	-
1823910	ENVIR CST UNDR AMORT	103446	Astoria/Unocal (Downtown)	SO	560	17	156	39	68	249	30	0	-
1823910	ENVIR CST UNDR AMORT	103447	Big Fork Hydro Plant (MT)	SO	634	19	177	44	77	282	34	0	-
1823910	ENVIR CST UNDR AMORT	103448	Bridger Coal Fuel Oil Spill	SO	517	16	144	36	63	230	28	0	-
1823910	ENVIR CST UNDR AMORT	103449	Bridger FGD Pond 1 Closure	SO	660	20	184	46	80	294	35	0	-
1823910	ENVIR CST UNDR AMORT	103450	Bridger Plant Oil Spills	SO	349	11	97	24	42	155	19	0	-
1823910	ENVIR CST UNDR AMORT	103451	Cedar Stream Plant (UT)	SO	36	1	10	3	4	16	2	0	-
1823910	ENVIR CST UNDR AMORT	103452	Dave Johnston Oil Spill	SO	244	7	68	17	30	109	13	0	-
1823910	ENVIR CST UNDR AMORT	103453	Eugene MGP (50% PCRP)	SO	149	5	42	10	18	67	8	0	-
1823910	ENVIR CST UNDR AMORT	103454	Everett MGP (2/3 PCRP)	SO	13	0	3	1	2	6	1	0	-
1823910	ENVIR CST UNDR AMORT	103455	Hunter Fuel Oil Spills	SO	2	0	1	0	0	1	0	0	-
1823910	ENVIR CST UNDR AMORT	103456	Huntington Ash Landfill	SO	1,104	33	308	77	134	491	59	0	-
1823910	ENVIR CST UNDR AMORT	103457	Idaho Falls Pole Yard	SO	1,273	39	355	89	155	567	68	0	-
1823910	ENVIR CST UNDR AMORT	103458	Jordan Plant Substation	SO	178	5	50	12	22	79	10	0	-
1823910	ENVIR CST UNDR AMORT	103460	Montague Ranch (CA)	SO	7	0	2	0	1	3	0	0	-
1823910	ENVIR CST UNDR AMORT	103461	Naughton FGD Pond Closure	SO	35	1	10	2	4	16	2	0	-
1823910	ENVIR CST UNDR AMORT	103462	Ogden MGP	SO	1,160	35	324	81	141	516	62	0	-
1823910	ENVIR CST UNDR AMORT	103465	Tacoma A St. (25% PCRP)	SO	76	2	21	5	9	34	4	0	-
1823910	ENVIR CST UNDR AMORT	103466	Portland Harbor Service Ctr	SO	5,812	176	1,622	408	706	2,587	313	0	-
1823910	ENVIR CST UNDR AMORT	103467	Wyodak Fuel Oil Spill	SO	110	3	31	8	13	49	6	0	-
1823910	ENVIR CST UNDR AMORT	103585	CLINE FALLS-HYDRO	SO	1	0	0	0	0	1	0	0	-
1823910	ENVIR CST UNDR AMORT	103851	Alturas Service Center (CA)	SO	0	0	0	0	0	0	0	0	-
1823910	ENVIR CST UNDR AMORT	103852	Pendleton Service Center (OR)	SO	0	0	0	0	0	0	0	0	-
1823910	ENVIR CST UNDR AMORT	103948	WASHINGTON NON-DEFERRED COSTS-SPPC PACI	WA	(17)	-	-	(17)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103949	WASHINGTON NON-DEFERRED COSTS-SPPC ROCK	WA	(10)	-	-	(10)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103950	WASHINGTON NON-DEFERRED COSTS-REMEDIATI	WA	(15)	-	-	(15)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103951	WASHINGTON NON-DEFERRED COSTS-REMEDIATI	WA	(98)	-	-	(98)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103961	D-SM RETAIL MINOR SITES - RMP	SO	3,283	100	916	230	399	1,461	177	0	-
1823910	ENVIR CST UNDR AMORT	104072	FREEPORT SUBSTATION	SO	14	0	4	1	2	6	1	0	-
1823910	ENVIR CST UNDR AMORT	104108	Bors Property (OR) - 2016	SO	5	0	1	0	1	2	0	0	-
1823910	ENVIR CST UNDR AMORT	104112	Carbon Ash Spill (UT) - 2016	SO	1,595	48	445	112	194	710	86	0	-
1823910	ENVIR CST UNDR AMORT	104143	Hunter Fuel Oil Spills - 2017	SO	0	0	0	0	0	0	0	0	-
1823910	ENVIR CST UNDR AMORT	104144	Naughton Oil Spill	SO	6	0	2	0	1	3	0	0	-
1823910	ENVIR CST UNDR AMORT	104175	Ririe Substation	SO	3	0	1	0	0	1	0	0	-
1823910	ENVIR CST UNDR AMORT	104197	Bridger Plant - FGD Pond 1	SO	2,760	84	770	194	335	1,228	148	0	-
1823910	ENVIR CST UNDR AMORT	104198	Bridger Plant - FGD Pond 2	SO	19	1	5	1	2	9	1	0	-
1823910	ENVIR CST UNDR AMORT	104199	Naughton Plant - FGD Pond 1	SO	7,384	224	2,061	518	897	3,286	397	0	-
1823910	ENVIR CST UNDR AMORT	104200	Naughton Plant - FGD Pond 2	SO	7,205	218	2,011	506	875	3,207	387	0	-
1823910	ENVIR CST UNDR AMORT	104201	Huntington Plant Ash Landfill	SO	723	22	202	51	88	322	39	0	-
1823910	ENVIR CST UNDR AMORT	104202	Dave Johnston Pond 4A & 4B	SO	2,492	76	695	175	303	1,109	134	0	-
1823910	ENVIR CST UNDR AMORT	104203	Colstrip Pond	SO	3,045	92	850	214	370	1,355	164	0	-
1823910	ENVIR CST UNDR AMORT	104204	Cholla Ash-Flyash Pond	SO	4,730	143	1,320	332	575	2,105	254	0	-
1823910	ENVIR CST UNDR AMORT	104205	Naughton North Ash Pond	SO	2	0	1	0	0	1	0	0	-
1823910	ENVIR CST UNDR AMORT	104206	Naughton South Ash Pond	SO	25	1	7	2	3	11	1	0	-
1823910	ENVIR CST UNDR AMORT	104210	American Barrel (UT)-WA	WA	(10)	-	-	(10)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104211	Astoria/Unocal (Downtown)-WA	WA	(35)	-	-	(35)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104212	ASTORIA YOUNGS BAY CLEANUP-WA	WA	(24)	-	-	(24)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104213	Big Fork Hydro Plant (MT)-WA	WA	(38)	-	-	(38)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104214	Bors Property (OR) - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104215	Bridger Coal Fuel Oil Spill - WA	WA	(34)	-	-	(34)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104216	Bridger FGD Pond 1 Closure-WA	WA	(42)	-	-	(42)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104218	Bridger Plant - FGD Pond 1-WA	WA	(188)	-	-	(188)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104219	Bridger Plant - FGD Pond 2-WA	WA	(1)	-	-	(1)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104220	Bridger Plant Oil Spills-2018	WA	(23)	-	-	(23)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104221	Carbon Ash Spill (UT) - WA	WA	(74)	-	-	(74)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104222	Cedar Steam - WA	WA	(2)	-	-	(2)	-	-	-	-	-

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Regulatory Assests (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-UPL + Wy-PPL	Utah	Id-PPL + Idaho	FERC	Other
1823910	ENVIR CST UNDR AMORT	104223	Colstrip Pond - WA	WA	(207)	-	-	(207)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104224	Cholla Ash - WA	WA	(318)	-	-	(318)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104225	DJ Oil Spill - WA	WA	(12)	-	-	(12)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104226	DJ 4A&4B - WA	WA	(169)	-	-	(169)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104227	Eugene MGP (50%PCRP) - WA	WA	(9)	-	-	(9)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104228	Everett MGP (2/3 PCRP) - WA	WA	(1)	-	-	(1)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104229	Hunter Plant - WA	WA	(52)	-	-	(52)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104230	Huntington Ash- WA	WA	(75)	-	-	(75)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104231	Idaho Falls Pole Yard- WA	WA	(82)	-	-	(82)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104232	Jordan Plant Substation- WA	WA	(11)	-	-	(11)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104233	Montague Ranch - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104234	Naughton Plant FGDP 1 - WA	WA	(501)	-	-	(501)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104235	Naughton Plant FGDP 2 - WA	WA	(491)	-	-	(491)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104236	Naughton Plant FGDP Closure - WA	WA	(2)	-	-	(2)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104237	Naughton Oil Spill - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104238	Naughton North Ash Pond - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104239	Naughton South Ash Pond - WA	WA	(2)	-	-	(2)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104240	Ogden MGP - WA	WA	(82)	-	-	(82)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104241	Olympia - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104242	Portland Harbor Srce Cntrl - WA	WA	(391)	-	-	(391)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104244	Silver Bell/Telluride - WA	WA	(367)	-	-	(367)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104245	Tacoma A St. (25% PCRP) - WA	WA	(5)	-	-	(5)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104246	Utah Metal East - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104247	Wyodak Oil Spill - WA	WA	(7)	-	-	(7)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104248	Hunter Fuel Oil Spill-WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104268	Rocky Mountain - WA	WA	(214)	-	-	(214)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104269	Pac Power - WA	WA	(242)	-	-	(242)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104275	Hayden Ash Landfill - WA	WA	0	-	-	0	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104296	NTO Parking Lot-Asbestos 2018	SO	75	2	21	5	9	34	4	0	-
1823910	ENVIR CST UNDR AMORT	104297	NTO Parking Lot Asbestos - WA 2018	WA	(6)	-	-	(6)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104394	Klamath Falls	SO	7,261	220	2,027	510	882	3,232	390	0	-
1823910	ENVIR CST UNDR AMORT	104395	Klamath Falls - WA 2021	WA	(493)	-	-	(493)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104399	Portland Harbor Service Insurance	SO	(1,059)	(32)	(296)	(74)	(129)	(471)	(57)	(0)	-
1823910	ENVIR CST UNDR AMORT	104400	Portland Harbor Srce Cntrl - Insurance W	WA	38	-	-	38	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104404	North Temple Office	SO	2,169	66	605	152	263	965	117	0	-
1823910	ENVIR CST UNDR AMORT	104405	North Temple Office WA	WA	(146)	-	-	(146)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104408	American Barrel (UT) - 2022	SO	514	16	144	36	62	229	28	0	-
1823910	ENVIR CST UNDR AMORT	104409	American Barrel (UT)-WA 2022	WA	(35)	-	-	(35)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104480	Rock Springs Pole Yard - 2024	SO	156	5	44	11	19	70	8	0	-
1823910	ENVIR CST UNDR AMORT	104481	Rock Springs Pole Yard - WA 2024	WA	(11)	-	-	(11)	-	-	-	-	-
1823910 Total					**60,661**	**1,976**	**18,187**	**68**	**7,918**	**29,007**	**3,504**	**2**	**-**
1823920	DSR COSTS AMORTIZED	0	DSR COST AMORT	OTHER	585,051	-	-	-	-	-	-	-	585,051
1823920	DSR COSTS AMORTIZED	102030	ENERGY FINANSWER - WASHINGTON	OTHER	5,065	-	-	-	-	-	-	-	5,065
1823920	DSR COSTS AMORTIZED	102032	INDUSTRIAL FINANSWER - WASHINGTON	OTHER	26,337	-	-	-	-	-	-	-	26,337
1823920	DSR COSTS AMORTIZED	102033	LOW INCOME - WASHINGTON	OTHER	10,718	-	-	-	-	-	-	-	10,718
1823920	DSR COSTS AMORTIZED	102034	SELF AUDIT - WASHINGTON	OTHER	14	-	-	-	-	-	-	-	14
1823920	DSR COSTS AMORTIZED	102036	COMMERCIAL SMALL RETROFIT - WASHINGTON	OTHER	788	-	-	-	-	-	-	-	788
1823920	DSR COSTS AMORTIZED	102037	INDUSTRIAL SMALL RETROFIT - WASHINGTON	OTHER	13	-	-	-	-	-	-	-	13
1823920	DSR COSTS AMORTIZED	102038	COMMERCIAL RETROFIT LIGHTING - WASHINGTO	OTHER	624	-	-	-	-	-	-	-	624
1823920	DSR COSTS AMORTIZED	102039	INDUSTRIAL RETROFIT LIGHTING-WA	OTHER	88	-	-	-	-	-	-	-	88
1823920	DSR COSTS AMORTIZED	102040	NEEA - WASHINGTON	OTHER	11,185	-	-	-	-	-	-	-	11,185
1823920	DSR COSTS AMORTIZED	102043	ENERGY CODE DEVELOPMENT	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	102044	HOME COMFORT - WASHINGTON	OTHER	162	-	-	-	-	-	-	-	162
1823920	DSR COSTS AMORTIZED	102045	WEATHERIZATION - WASHINGTON	OTHER	22	-	-	-	-	-	-	-	22
1823920	DSR COSTS AMORTIZED	102046	HASSLE FREE	OTHER	41	-	-	-	-	-	-	-	41
1823920	DSR COSTS AMORTIZED	102072	COMPACT FLUORESCENT LAMPS - WASHINGTON	OTHER	1,183	-	-	-	-	-	-	-	1,183
1823920	DSR COSTS AMORTIZED	102127	RESIDENTIAL PROGRAM RESEARCH - WA	OTHER	24	-	-	-	-	-	-	-	24
1823920	DSR COSTS AMORTIZED	102128	WA REVENUE RECOVERY - SBC OFFSET	OTHER	(114,872)	-	-	-	-	-	-	-	(114,872)
1823920	DSR COSTS AMORTIZED	102131	ENERGY FINANSWER - UTAH 2001/2002	OTHER	1,280	-	-	-	-	-	-	-	1,280
1823920	DSR COSTS AMORTIZED	102133	INDUSTRIAL FINANSWER - UTAH 2001/2002	OTHER	1,353	-	-	-	-	-	-	-	1,353
1823920	DSR COSTS AMORTIZED	102138	COMPACT FLUOR LAMPS (CFL) UT 2001/2002	OTHER	4,202	-	-	-	-	-	-	-	4,202
1823920	DSR COSTS AMORTIZED	102147	COMMERCIAL SMALL RETROFIT - UT 2001/2002	OTHER	848	-	-	-	-	-	-	-	848
1823920	DSR COSTS AMORTIZED	102148	INDUSTRIAL SMALL RETROFIT - UT 2002	OTHER	0	-	-	-	-	-	-	-	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-UPL + Wy-PPL	Utah	Id-PPL + Idaho	FERC	Other
1823920	DSR COSTS AMORTIZED	102149	COMMERCIAL RETROFIT LIGHTING - UT 2001/2	OTHER	498	-	-	-	-	-	-	-	498
1823920	DSR COSTS AMORTIZED	102150	INDUSTRIAL RETROFIT LIGHTING - UT 2001/2	OTHER	82	-	-	-	-	-	-	-	82
1823920	DSR COSTS AMORTIZED	102185	WEB AUDIT PILOT - WA	OTHER	527	-	-	-	-	-	-	-	527
1823920	DSR COSTS AMORTIZED	102186	APPLIANCE REBATE - WA	OTHER	18	-	-	-	-	-	-	-	18
1823920	DSR COSTS AMORTIZED	102195	INDUSTRIAL RETROFIT LIGHTING - UT 2002	OTHER	71	-	-	-	-	-	-	-	71
1823920	DSR COSTS AMORTIZED	102196	POWER FORWARD UT 2002	OTHER	115	-	-	-	-	-	-	-	115
1823920	DSR COSTS AMORTIZED	102205	A/C LOAD CONTROL PGM - RESIDENTIAL - UT	OTHER	28	-	-	-	-	-	-	-	28
1823920	DSR COSTS AMORTIZED	102206	SCHOOL ENERGY EDUCATION - WA	OTHER	3,807	-	-	-	-	-	-	-	3,807
1823920	DSR COSTS AMORTIZED	102209	AIR CONDITIONING - UT 2002	OTHER	24	-	-	-	-	-	-	-	24
1823920	DSR COSTS AMORTIZED	102213	REFRIGERATOR RECYCLING PGM - UT 2003	OTHER	1,509	-	-	-	-	-	-	-	1,509
1823920	DSR COSTS AMORTIZED	102214	REFRIGERATOR RECYCLING PGM - WA	OTHER	3,675	-	-	-	-	-	-	-	3,675
1823920	DSR COSTS AMORTIZED	102223	A/C LOAD CONTROL - RESIDENTIAL UT 2003	OTHER	460	-	-	-	-	-	-	-	460
1823920	DSR COSTS AMORTIZED	102225	AIR CONDITIONING - UT 2003	OTHER	2,564	-	-	-	-	-	-	-	2,564
1823920	DSR COSTS AMORTIZED	102226	COMMERCIAL RETROFIT LIGHTING - UT 2003	OTHER	1,187	-	-	-	-	-	-	-	1,187
1823920	DSR COSTS AMORTIZED	102227	COMMERCIAL SMALL RETROFIT - UT 2003	OTHER	895	-	-	-	-	-	-	-	895
1823920	DSR COSTS AMORTIZED	102228	COMPACT FLOURESCENT LAMP (CFL) - UT 2002	OTHER	13	-	-	-	-	-	-	-	13
1823920	DSR COSTS AMORTIZED	102229	ENERGY FINANSWER - UT 2003	OTHER	1,542	-	-	-	-	-	-	-	1,542
1823920	DSR COSTS AMORTIZED	102230	INDUSTRIAL FINANSWER - UT 2003	OTHER	1,658	-	-	-	-	-	-	-	1,658
1823920	DSR COSTS AMORTIZED	102231	INDUSTRIAL RETROFIT LIGHTING - UT 2003	OTHER	191	-	-	-	-	-	-	-	191
1823920	DSR COSTS AMORTIZED	102232	INDUSTRIAL SMALL RETROFIT - UTAH - 2003	OTHER	14	-	-	-	-	-	-	-	14
1823920	DSR COSTS AMORTIZED	102233	POWER FORWARD - UT 2003	OTHER	(27)	-	-	-	-	-	-	-	(27)
1823920	DSR COSTS AMORTIZED	102245	CA REVENUE RECOVERY - BALANCING ACCT	OTHER	(0)	-	-	-	-	-	-	-	(0)
1823920	DSR COSTS AMORTIZED	102327	COMMERCIAL SELF-DIRECT UT 2003	OTHER	4	-	-	-	-	-	-	-	4
1823920	DSR COSTS AMORTIZED	102328	INDUSTRIAL SELF-DIRECT UT 2003	OTHER	7	-	-	-	-	-	-	-	7
1823920	DSR COSTS AMORTIZED	102336	LOW INCOME - UTAH - 2004	OTHER	22	-	-	-	-	-	-	-	22
1823920	DSR COSTS AMORTIZED	102337	REFRIGERATOR RECYCLING PGM - UT 2004	OTHER	3,581	-	-	-	-	-	-	-	3,581
1823920	DSR COSTS AMORTIZED	102338	AC LOAD CONTROL - RESIDENTIAL UT 2004	OTHER	2,910	-	-	-	-	-	-	-	2,910
1823920	DSR COSTS AMORTIZED	102339	AIR CONDITIONING - UT 2004	OTHER	3,026	-	-	-	-	-	-	-	3,026
1823920	DSR COSTS AMORTIZED	102340	COMMERCIAL RETROFIT LIGHTING - UT 2004	OTHER	1,547	-	-	-	-	-	-	-	1,547
1823920	DSR COSTS AMORTIZED	102341	COMMERCIAL SMALL RETROFIT - UT 2004	OTHER	285	-	-	-	-	-	-	-	285
1823920	DSR COSTS AMORTIZED	102342	COMPACT FLOURESCENT LAMPS (CFL) UT 2004	OTHER	(1)	-	-	-	-	-	-	-	(1)
1823920	DSR COSTS AMORTIZED	102343	ENERGY FINANSWER - UT 2004	OTHER	1,227	-	-	-	-	-	-	-	1,227
1823920	DSR COSTS AMORTIZED	102344	INDUSTRIAL FINANSWER - UT 2004	OTHER	2,562	-	-	-	-	-	-	-	2,562
1823920	DSR COSTS AMORTIZED	102345	INDUSTRIAL RETROFIT - UT 2004	OTHER	230	-	-	-	-	-	-	-	230
1823920	DSR COSTS AMORTIZED	102346	INDUSTRIAL SMALL RETROFIT - UT 2004	OTHER	51	-	-	-	-	-	-	-	51
1823920	DSR COSTS AMORTIZED	102347	POWER FORWARD - UT 2004	OTHER	54	-	-	-	-	-	-	-	54
1823920	DSR COSTS AMORTIZED	102348	COMMERCIAL SELF-DIRECT - UT 2004	OTHER	89	-	-	-	-	-	-	-	89
1823920	DSR COSTS AMORTIZED	102349	INDUSTRIAL SELF-DIRECT - UT 2004	OTHER	129	-	-	-	-	-	-	-	129
1823920	DSR COSTS AMORTIZED	102443	ESIDENTIAL NEW CONSTRUCTION - WASHINGTON	OTHER	561	-	-	-	-	-	-	-	561
1823920	DSR COSTS AMORTIZED	102444	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	76	-	-	-	-	-	-	-	76
1823920	DSR COSTS AMORTIZED	102458	COMMERCIAL FINANSWER EXPRESS - WASHINGTO	OTHER	9,257	-	-	-	-	-	-	-	9,257
1823920	DSR COSTS AMORTIZED	102459	INDUSTRIAL FINANSWER EXPRESS - WASHINGTO	OTHER	3,275	-	-	-	-	-	-	-	3,275
1823920	DSR COSTS AMORTIZED	102460	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	446	-	-	-	-	-	-	-	446
1823920	DSR COSTS AMORTIZED	102461	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	146	-	-	-	-	-	-	-	146
1823920	DSR COSTS AMORTIZED	102462	UTAH REVENUE RECOVERY - SBC OFFSET	OTHER	(587,832)	-	-	-	-	-	-	-	(587,832)
1823920	DSR COSTS AMORTIZED	102502	RETROFIT COMMISSIONING PROGRAM - UTAH	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	102503	C&I LIGHTING LOAD CONTROL - UTAH - 2004	OTHER	23	-	-	-	-	-	-	-	23
1823920	DSR COSTS AMORTIZED	102532	LOW INCOME - UTAH - 2005	OTHER	48	-	-	-	-	-	-	-	48
1823920	DSR COSTS AMORTIZED	102533	REFRIGERATOR RECYCLING PGM- UTAH - 2005	OTHER	3,306	-	-	-	-	-	-	-	3,306
1823920	DSR COSTS AMORTIZED	102534	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	3,060	-	-	-	-	-	-	-	3,060
1823920	DSR COSTS AMORTIZED	102535	AIR CONDITIONING - UTAH - 2005	OTHER	2,347	-	-	-	-	-	-	-	2,347
1823920	DSR COSTS AMORTIZED	102536	COMMERCIAL RETROFIT LIGHTING - UTAH - 20	OTHER	65	-	-	-	-	-	-	-	65
1823920	DSR COSTS AMORTIZED	102537	COMMERCIAL SMALL RETROFIT - UTAH - 2005	OTHER	223	-	-	-	-	-	-	-	223
1823920	DSR COSTS AMORTIZED	102539	ENERGY FINANSWER - UTAH - 2005	OTHER	1,476	-	-	-	-	-	-	-	1,476
1823920	DSR COSTS AMORTIZED	102540	INDUSTRIAL FINANSWER - UTAH - 2005	OTHER	3,485	-	-	-	-	-	-	-	3,485
1823920	DSR COSTS AMORTIZED	102541	INDUSTRIAL RETROFIT LIGHTING - UTAH - 20	OTHER	60	-	-	-	-	-	-	-	60
1823920	DSR COSTS AMORTIZED	102543	POWER FORWARD - UTAH - 2005	OTHER	50	-	-	-	-	-	-	-	50
1823920	DSR COSTS AMORTIZED	102544	COMMERCIAL SELF-DIRECT - UTAH - 2005	OTHER	67	-	-	-	-	-	-	-	67
1823920	DSR COSTS AMORTIZED	102545	INDUSTRIAL SELF-DIRECT - UTAH - 2005	OTHER	103	-	-	-	-	-	-	-	103
1823920	DSR COSTS AMORTIZED	102546	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	944	-	-	-	-	-	-	-	944
1823920	DSR COSTS AMORTIZED	102547	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,967	-	-	-	-	-	-	-	1,967
1823920	DSR COSTS AMORTIZED	102548	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	421	-	-	-	-	-	-	-	421
1823920	DSR COSTS AMORTIZED	102549	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	105	-	-	-	-	-	-	-	105

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1823920	DSR COSTS AMORTIZED	102550	C&I LIGHTING LOAD CONTROL - UTAH - 2005	OTHER	36	-	-	-	-	-	-	-	36
1823920	DSR COSTS AMORTIZED	102556	1823920/102556	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	102562	APPLIANCE INCENTIVE - WASHWISE - WASHING	OTHER	53	-	-	-	-	-	-	-	53
1823920	DSR COSTS AMORTIZED	102586	IRRIGATION LOAD CONTROL - UTAH - 2005	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	102706	LOW INCOME-UTAH-2006	OTHER	119	-	-	-	-	-	-	-	119
1823920	DSR COSTS AMORTIZED	102707	REFRIGERATOR RECYCLING PGM-UTAH-2006	OTHER	3,752	-	-	-	-	-	-	-	3,752
1823920	DSR COSTS AMORTIZED	102708	A/C LOAD CONTROL-RESIDENTIAL/UTAH-2006	OTHER	8,624	-	-	-	-	-	-	-	8,624
1823920	DSR COSTS AMORTIZED	102709	AIR CONDITIONING-UTAH-2006	OTHER	1,499	-	-	-	-	-	-	-	1,499
1823920	DSR COSTS AMORTIZED	102712	ENERGY FINANSWER-UTAH-2006	OTHER	2,187	-	-	-	-	-	-	-	2,187
1823920	DSR COSTS AMORTIZED	102713	INDUSTRIAL FINANSWER-WYOMING-UTAH-2006	OTHER	2,748	-	-	-	-	-	-	-	2,748
1823920	DSR COSTS AMORTIZED	102717	COMMERCIAL SELF-DIRECT-UTAH-2006	OTHER	65	-	-	-	-	-	-	-	65
1823920	DSR COSTS AMORTIZED	102718	INDUSTRIAL SELF-DIRECT-UTAH-2006	OTHER	122	-	-	-	-	-	-	-	122
1823920	DSR COSTS AMORTIZED	102719	RESIDENTIAL NEW CONSTRUCTION-UTAH-2006	OTHER	1,848	-	-	-	-	-	-	-	1,848
1823920	DSR COSTS AMORTIZED	102720	COMMERCIAL FINANSWER EXPRESS-UTAH-2006	OTHER	2,469	-	-	-	-	-	-	-	2,469
1823920	DSR COSTS AMORTIZED	102721	INDUSTRIAL FINANSWER-UTAH-2006	OTHER	536	-	-	-	-	-	-	-	536
1823920	DSR COSTS AMORTIZED	102722	RETROFIT COMMISSIONING PROGRAM -UTAH-200	OTHER	211	-	-	-	-	-	-	-	211
1823920	DSR COSTS AMORTIZED	102723	C&I LIGHTING LOAD CONTROL -UTAH-2006	OTHER	8	-	-	-	-	-	-	-	8
1823920	DSR COSTS AMORTIZED	102725	CALIFORNIA DSM EXPENSE-2006	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	102759	HOME ENERGY EFF INCENTIVE PROG-UTAH-2006	OTHER	241	-	-	-	-	-	-	-	241
1823920	DSR COSTS AMORTIZED	102760	HOME ENERGY EFF INCENTIVE PROG-WA-2006	OTHER	15,240	-	-	-	-	-	-	-	15,240
1823920	DSR COSTS AMORTIZED	102767	DSR COSTS BEING AMORTIZED	OTHER	(44,183)	-	-	-	-	-	-	-	(44,183)
1823920	DSR COSTS AMORTIZED	102796	DSR COSTS BEING AMORTIZED	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	102819	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	5,982	-	-	-	-	-	-	-	5,982
1823920	DSR COSTS AMORTIZED	102820	AIR CONDITIONING - UTAH - 2007	OTHER	883	-	-	-	-	-	-	-	883
1823920	DSR COSTS AMORTIZED	102821	ENERGY FINANSWER - UTAH - 2007	OTHER	1,952	-	-	-	-	-	-	-	1,952
1823920	DSR COSTS AMORTIZED	102822	INDUSTRIAL FINANSWER - UTAH - 2007	OTHER	3,369	-	-	-	-	-	-	-	3,369
1823920	DSR COSTS AMORTIZED	102823	LOW INCOME - UTAH - 2007	OTHER	117	-	-	-	-	-	-	-	117
1823920	DSR COSTS AMORTIZED	102824	POWER FORWARD - UTAH - 2007	OTHER	50	-	-	-	-	-	-	-	50
1823920	DSR COSTS AMORTIZED	102825	REFRIGERATOR RECYCLING PGM- UTAH - 2007	OTHER	3,399	-	-	-	-	-	-	-	3,399
1823920	DSR COSTS AMORTIZED	102826	COMMERCIAL SELF-DIRECT - UTAH - 2007	OTHER	61	-	-	-	-	-	-	-	61
1823920	DSR COSTS AMORTIZED	102827	INDUSTRIAL SELF-DIRECT - UTAH - 2007	OTHER	108	-	-	-	-	-	-	-	108
1823920	DSR COSTS AMORTIZED	102828	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,936	-	-	-	-	-	-	-	1,936
1823920	DSR COSTS AMORTIZED	102829	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	3,277	-	-	-	-	-	-	-	3,277
1823920	DSR COSTS AMORTIZED	102830	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	968	-	-	-	-	-	-	-	968
1823920	DSR COSTS AMORTIZED	102831	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	187	-	-	-	-	-	-	-	187
1823920	DSR COSTS AMORTIZED	102833	IRRIGATION LOAD CONTROL - UTAH - 2007	OTHER	277	-	-	-	-	-	-	-	277
1823920	DSR COSTS AMORTIZED	102834	HOME ENERGY EFF INCENTIVE PROG - UT 2007	OTHER	3,034	-	-	-	-	-	-	-	3,034
1823920	DSR COSTS AMORTIZED	102883	CALIFORNIA DSM EXPENSE - 2008	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	102906	AC LOAD CONTROL - RESIDENTIAL - UTAH 200	OTHER	7,175	-	-	-	-	-	-	-	7,175
1823920	DSR COSTS AMORTIZED	102907	AIR CONDITIONING - UTAH 2008	OTHER	526	-	-	-	-	-	-	-	526
1823920	DSR COSTS AMORTIZED	102908	ENERGY FINANSWER - UTAH - 2008	OTHER	3,466	-	-	-	-	-	-	-	3,466
1823920	DSR COSTS AMORTIZED	102909	INDUSTRIAL FINANSWER - UTAH - 2008	OTHER	4,289	-	-	-	-	-	-	-	4,289
1823920	DSR COSTS AMORTIZED	102910	LOW INCOME - UTAH 2008	OTHER	127	-	-	-	-	-	-	-	127
1823920	DSR COSTS AMORTIZED	102911	POWER FORWARD - UTAH - 2008	OTHER	50	-	-	-	-	-	-	-	50
1823920	DSR COSTS AMORTIZED	102912	REFRIGERATOR RECYCLING - UTAH - 2008	OTHER	2,570	-	-	-	-	-	-	-	2,570
1823920	DSR COSTS AMORTIZED	102913	COMMERCIAL SELF DIRECT - UTAH - 2008	OTHER	83	-	-	-	-	-	-	-	83
1823920	DSR COSTS AMORTIZED	102914	INDUSTRIAL SELF DIRECT - UTAH - 2008	OTHER	126	-	-	-	-	-	-	-	126
1823920	DSR COSTS AMORTIZED	102915	RESIDENTIAL NEW CONSTRUCTION - UTAH 2008	OTHER	1,664	-	-	-	-	-	-	-	1,664
1823920	DSR COSTS AMORTIZED	102916	COMMERCIAL FINANSWER EXPRESS - UTAH 2008	OTHER	3,791	-	-	-	-	-	-	-	3,791
1823920	DSR COSTS AMORTIZED	102917	INDUSTRIAL FINANSWER EXPRESS - UTAH 2008	OTHER	1,133	-	-	-	-	-	-	-	1,133
1823920	DSR COSTS AMORTIZED	102918	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	1,053	-	-	-	-	-	-	-	1,053
1823920	DSR COSTS AMORTIZED	102919	C&I LIGHTING LOAD CONTROL - UTAH - 2008	OTHER	4	-	-	-	-	-	-	-	4
1823920	DSR COSTS AMORTIZED	102920	IRRIGATION LOAD CONTROL - UTAH	OTHER	762	-	-	-	-	-	-	-	762
1823920	DSR COSTS AMORTIZED	102921	HOME ENERGY EFF INCENTIVE PROGRAM - UTAH	OTHER	7,817	-	-	-	-	-	-	-	7,817
1823920	DSR COSTS AMORTIZED	102964	CALIFORNIA DSM EXPENSE - 2009	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	102976	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	9,817	-	-	-	-	-	-	-	9,817
1823920	DSR COSTS AMORTIZED	102977	AIR CONDITIONING - UTAH - 2009	OTHER	500	-	-	-	-	-	-	-	500
1823920	DSR COSTS AMORTIZED	102978	ENERGY FINANSWER - UTAH - 2009	OTHER	2,532	-	-	-	-	-	-	-	2,532
1823920	DSR COSTS AMORTIZED	102979	INDUSTRIAL FINANSWER - UTAH - 2009	OTHER	5,215	-	-	-	-	-	-	-	5,215
1823920	DSR COSTS AMORTIZED	102980	LOW INCOME - UTAH - 2009	OTHER	162	-	-	-	-	-	-	-	162
1823920	DSR COSTS AMORTIZED	102981	POWER FORWARD - UTAH - 2009	OTHER	50	-	-	-	-	-	-	-	50
1823920	DSR COSTS AMORTIZED	102982	REFRIGERATOR RECYCLING PGM- UTAH - 2009	OTHER	2,339	-	-	-	-	-	-	-	2,339
1823920	DSR COSTS AMORTIZED	102983	COMMERCIAL SELF-DIRECT - UTAH - 2009	OTHER	53	-	-	-	-	-	-	-	53

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-UPL + Wy-PPL	Utah	Id-PPL + Idaho	FERC	Other
1823920	DSR COSTS AMORTIZED	102984	INDUSTRIAL SELF-DIRECT - UTAH - 2009	OTHER	72	-	-	-	-	-	-	-	72
1823920	DSR COSTS AMORTIZED	102985	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,446	-	-	-	-	-	-	-	1,446
1823920	DSR COSTS AMORTIZED	102986	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	3,258	-	-	-	-	-	-	-	3,258
1823920	DSR COSTS AMORTIZED	102987	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	776	-	-	-	-	-	-	-	776
1823920	DSR COSTS AMORTIZED	102988	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	947	-	-	-	-	-	-	-	947
1823920	DSR COSTS AMORTIZED	102990	IRRIGATION LOAD CONTROL - UTAH - 2009	OTHER	2,732	-	-	-	-	-	-	-	2,732
1823920	DSR COSTS AMORTIZED	102991	HOME ENERGY EFF INCENTIVE PROG - UT 2009	OTHER	25,439	-	-	-	-	-	-	-	25,439
1823920	DSR COSTS AMORTIZED	102992	ENERGY FINANSWER - WYOMING PPL - 2009	OTHER	21	-	-	-	-	-	-	-	21
1823920	DSR COSTS AMORTIZED	102993	INDUSTRIAL FINANSWER-WYOMING - PPL 2009	OTHER	96	-	-	-	-	-	-	-	96
1823920	DSR COSTS AMORTIZED	102995	REFRIGERATOR RECYCLING - PPL WYOMING - 2	OTHER	140	-	-	-	-	-	-	-	140
1823920	DSR COSTS AMORTIZED	102996	HOME ENERGY EFF INCENTIVE PRO - PPL WYOM	OTHER	439	-	-	-	-	-	-	-	439
1823920	DSR COSTS AMORTIZED	102997	LOW-INCOME WEATHERIZATION - WYOMING PPL	OTHER	86	-	-	-	-	-	-	-	86
1823920	DSR COSTS AMORTIZED	102998	COMMERCIAL FINANSWER EXPRESS - WY - 2009	OTHER	139	-	-	-	-	-	-	-	139
1823920	DSR COSTS AMORTIZED	102999	INDUSTRIAL FINANSWER EXPRESS - WY - 2009	OTHER	59	-	-	-	-	-	-	-	59
1823920	DSR COSTS AMORTIZED	103000	SELF DIRECT - COMMERCIAL - WY - 2009	OTHER	5	-	-	-	-	-	-	-	5
1823920	DSR COSTS AMORTIZED	103001	SELF DIRECT - INDUSTRIAL - WY - 2009	OTHER	12	-	-	-	-	-	-	-	12
1823920	DSR COSTS AMORTIZED	103003	MAIN CHECK DISB-WIRES/ACH IN CLEAR ACCT	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103004	MAIN CHECK DISB-WIRES/ACH OUT CLEAR ACCT	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103005	COMMERCIAL FINANSWER EXPRESS Cat 2- WY -	OTHER	236	-	-	-	-	-	-	-	236
1823920	DSR COSTS AMORTIZED	103006	INDUSTRIAL FINANSWER EXPRESS Cat 2- WY -	OTHER	34	-	-	-	-	-	-	-	34
1823920	DSR COSTS AMORTIZED	103007	ENERGY FINANSWER Cat 2 - WY 2009	OTHER	40	-	-	-	-	-	-	-	40
1823920	DSR COSTS AMORTIZED	103008	INDUSTRIAL FINANSWER Cat 2 -WY 2009	OTHER	34	-	-	-	-	-	-	-	34
1823920	DSR COSTS AMORTIZED	103012	WYOMING REV RECOVERY - SBC OFFSET CAT 1	OTHER	(10,759)	-	-	-	-	-	-	-	(10,759)
1823920	DSR COSTS AMORTIZED	103013	WYOMING REV RECOVERY - SBC OFFSET CAT 2	OTHER	(10,609)	-	-	-	-	-	-	-	(10,609)
1823920	DSR COSTS AMORTIZED	103014	WYOMING REV RECOVERY - SBC OFFSET CAT 3	OTHER	(10,192)	-	-	-	-	-	-	-	(10,192)
1823920	DSR COSTS AMORTIZED	103031	OUTREACH and COMMUNICATIONS - UT 2009	OTHER	571	-	-	-	-	-	-	-	571
1823920	DSR COSTS AMORTIZED	103059	CALIFORNIA DSM EXPENSE - 2010	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103071	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	4,836	-	-	-	-	-	-	-	4,836
1823920	DSR COSTS AMORTIZED	103072	AIR CONDITIONING - UTAH - 2010	OTHER	1,490	-	-	-	-	-	-	-	1,490
1823920	DSR COSTS AMORTIZED	103073	ENERGY FINANSWER - UTAH - 2010	OTHER	3,246	-	-	-	-	-	-	-	3,246
1823920	DSR COSTS AMORTIZED	103074	INDUSTRIAL FINANSWER - UTAH - 2010	OTHER	4,524	-	-	-	-	-	-	-	4,524
1823920	DSR COSTS AMORTIZED	103075	LOW INCOME - UTAH - 2010	OTHER	258	-	-	-	-	-	-	-	258
1823920	DSR COSTS AMORTIZED	103076	POWER FORWARD - UTAH # 2010	OTHER	50	-	-	-	-	-	-	-	50
1823920	DSR COSTS AMORTIZED	103077	REFRIGERATOR RECYCLING PGM- UTAH - 2010	OTHER	2,370	-	-	-	-	-	-	-	2,370
1823920	DSR COSTS AMORTIZED	103078	COMMERCIAL SELF-DIRECT - UTAH - 2010	OTHER	187	-	-	-	-	-	-	-	187
1823920	DSR COSTS AMORTIZED	103079	INDUSTRIAL SELF-DIRECT - UTAH - 2010	OTHER	330	-	-	-	-	-	-	-	330
1823920	DSR COSTS AMORTIZED	103080	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	2,605	-	-	-	-	-	-	-	2,605
1823920	DSR COSTS AMORTIZED	103081	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	4,107	-	-	-	-	-	-	-	4,107
1823920	DSR COSTS AMORTIZED	103082	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,019	-	-	-	-	-	-	-	1,019
1823920	DSR COSTS AMORTIZED	103083	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	986	-	-	-	-	-	-	-	986
1823920	DSR COSTS AMORTIZED	103085	IRRIGATION LOAD CONTROL - UTAH - 2010	OTHER	2,513	-	-	-	-	-	-	-	2,513
1823920	DSR COSTS AMORTIZED	103086	HOME ENERGY EFF INCENTIVE PROG - UT 2010	OTHER	16,876	-	-	-	-	-	-	-	16,876
1823920	DSR COSTS AMORTIZED	103087	OUTREACH and COMMUNICATIONS - UT 2010	OTHER	1,485	-	-	-	-	-	-	-	1,485
1823920	DSR COSTS AMORTIZED	103089	ENERGY FINANSWER-WY-2010 CAT3	OTHER	11	-	-	-	-	-	-	-	11
1823920	DSR COSTS AMORTIZED	103090	INDUSTRIAL FINANSWER-WY-2010 CAT3	OTHER	669	-	-	-	-	-	-	-	669
1823920	DSR COSTS AMORTIZED	103092	REFRIGERATOR RECYCLING-WY -2010 CAT1	OTHER	176	-	-	-	-	-	-	-	176
1823920	DSR COSTS AMORTIZED	103093	HOME ENERGY EFF INCENT PROG Y-2010 CAT1	OTHER	740	-	-	-	-	-	-	-	740
1823920	DSR COSTS AMORTIZED	103094	LOW-INCOME WEATHERZTN - WY 2010 CAT1	OTHER	49	-	-	-	-	-	-	-	49
1823920	DSR COSTS AMORTIZED	103095	COMMERCIAL FINANSWER EXP WY-2010 CAT3	OTHER	65	-	-	-	-	-	-	-	65
1823920	DSR COSTS AMORTIZED	103096	INDUSTRIAL FINANSWER EXP WY-2010 CAT3	OTHER	127	-	-	-	-	-	-	-	127
1823920	DSR COSTS AMORTIZED	103097	SELF DIRECT - COMMERCIAL -WY-2010 CAT3	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	103098	SELF DIRECT -INDUSTRIAL -WY-2010 CAT3	OTHER	12	-	-	-	-	-	-	-	12
1823920	DSR COSTS AMORTIZED	103099	COMMERCIAL FINANSWER EXP- WY-2010 CAT2	OTHER	587	-	-	-	-	-	-	-	587
1823920	DSR COSTS AMORTIZED	103100	INDUSTRIAL FINAN EXPRESS WY-2010 CAT2	OTHER	55	-	-	-	-	-	-	-	55
1823920	DSR COSTS AMORTIZED	103101	ENERGY FINANSWER -WY 2010 CAT2	OTHER	186	-	-	-	-	-	-	-	186
1823920	DSR COSTS AMORTIZED	103102	INDUSTRIAL FINANSWER -WY 2010 CAT2	OTHER	125	-	-	-	-	-	-	-	125
1823920	DSR COSTS AMORTIZED	103103	Check Disb-Wires/ACH In Clearing - BT	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103104	Check Disb-Wires/ACH Out Clearing - BT	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	103137	Company Initiatives DEI Study- Washingto	OTHER	724	-	-	-	-	-	-	-	724
1823920	DSR COSTS AMORTIZED	103163	Commercial Direct Install - Utah - 2011	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	103164	Commercial Curtailment - Utah - 2011	OTHER	30	-	-	-	-	-	-	-	30
1823920	DSR COSTS AMORTIZED	103165	Commercial Direct Install - Washington	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103168	CALIFORNIA DSM EXPENSE - 2011	OTHER	0	-	-	-	-	-	-	-	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-UPL + Wy-PPL	Utah	Id-PPL + Idaho	FERC	Other
1823920	DSR COSTS AMORTIZED	103169	Commercial Curtailment - Oregon	OTHER	27	-	-	-	-	-	-	-	27
1823920	DSR COSTS AMORTIZED	103181	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	6,498	-	-	-	-	-	-	-	6,498
1823920	DSR COSTS AMORTIZED	103182	AIR CONDITIONING - UTAH - 2011	OTHER	1,305	-	-	-	-	-	-	-	1,305
1823920	DSR COSTS AMORTIZED	103183	ENERGY FINANSWER - UTAH - 2011	OTHER	3,647	-	-	-	-	-	-	-	3,647
1823920	DSR COSTS AMORTIZED	103184	INDUSTRIAL FINANSWER - UTAH - 2011	OTHER	5,016	-	-	-	-	-	-	-	5,016
1823920	DSR COSTS AMORTIZED	103185	LOW INCOME - UTAH - 2011	OTHER	255	-	-	-	-	-	-	-	255
1823920	DSR COSTS AMORTIZED	103186	Power Forward - Utah - 2011	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103187	REFRIGERATOR RECYCLING PGM- UTAH - 2011	OTHER	1,880	-	-	-	-	-	-	-	1,880
1823920	DSR COSTS AMORTIZED	103188	COMMERCIAL SELF-DIRECT - UTAH - 2011	OTHER	126	-	-	-	-	-	-	-	126
1823920	DSR COSTS AMORTIZED	103189	INDUSTRIAL SELF-DIRECT - UTAH - 2011	OTHER	240	-	-	-	-	-	-	-	240
1823920	DSR COSTS AMORTIZED	103190	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	3,071	-	-	-	-	-	-	-	3,071
1823920	DSR COSTS AMORTIZED	103191	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	4,607	-	-	-	-	-	-	-	4,607
1823920	DSR COSTS AMORTIZED	103192	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,233	-	-	-	-	-	-	-	1,233
1823920	DSR COSTS AMORTIZED	103193	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	411	-	-	-	-	-	-	-	411
1823920	DSR COSTS AMORTIZED	103195	IRRIGATION LOAD CONTROL - UTAH - 2011	OTHER	2,513	-	-	-	-	-	-	-	2,513
1823920	DSR COSTS AMORTIZED	103196	HOME ENERGY EFF INCENTIVE PROG - UT 2011	OTHER	11,360	-	-	-	-	-	-	-	11,360
1823920	DSR COSTS AMORTIZED	103197	OUTREACH and COMMUNICATIONS - UT 2011	OTHER	1,437	-	-	-	-	-	-	-	1,437
1823920	DSR COSTS AMORTIZED	103199	ENERGY FINANSWER-WY-2011 CAT3	OTHER	30	-	-	-	-	-	-	-	30
1823920	DSR COSTS AMORTIZED	103200	INDUSTRIAL FINANSWER-WY-2011 CAT3	OTHER	433	-	-	-	-	-	-	-	433
1823920	DSR COSTS AMORTIZED	103202	REFRIGERATOR RECYCLING-WY -2011 CAT1	OTHER	183	-	-	-	-	-	-	-	183
1823920	DSR COSTS AMORTIZED	103203	HOME ENERGY EFF INCENT PROG Y-2011 CAT1	OTHER	1,070	-	-	-	-	-	-	-	1,070
1823920	DSR COSTS AMORTIZED	103204	Low-Income Weatherztn - Wy 2011 CAT1	OTHER	42	-	-	-	-	-	-	-	42
1823920	DSR COSTS AMORTIZED	103205	COMMERCIAL FINANSWER EXP WY-2011 CAT3	OTHER	102	-	-	-	-	-	-	-	102
1823920	DSR COSTS AMORTIZED	103206	INDUSTRIAL FINANSWER EXP WY-2011 CAT3	OTHER	168	-	-	-	-	-	-	-	168
1823920	DSR COSTS AMORTIZED	103207	Self Direct - Commercial -Wy-2011 CAT3	OTHER	6	-	-	-	-	-	-	-	6
1823920	DSR COSTS AMORTIZED	103208	Self Direct -Industrial -Wy-2011 CAT3	OTHER	268	-	-	-	-	-	-	-	268
1823920	DSR COSTS AMORTIZED	103209	COMMERCIAL FINANSWER EXP- WY-2011 CAT2	OTHER	894	-	-	-	-	-	-	-	894
1823920	DSR COSTS AMORTIZED	103210	INDUSTRIAL FINAN EXPRESS WY-2011 CAT2	OTHER	55	-	-	-	-	-	-	-	55
1823920	DSR COSTS AMORTIZED	103211	ENERGY FINANSWER -WY 2011 CAT2	OTHER	51	-	-	-	-	-	-	-	51
1823920	DSR COSTS AMORTIZED	103212	INDUSTRIAL FINANSWER -WY 2011 CAT2	OTHER	98	-	-	-	-	-	-	-	98
1823920	DSR COSTS AMORTIZED	103213	Self Direct - Commercial Wy-2011 CAT2	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	103214	Self Direct- Industrial Wy-2011 CAT2	OTHER	11	-	-	-	-	-	-	-	11
1823920	DSR COSTS AMORTIZED	103277	OUTREACH & COMM- WATTSMART - EVALUATION	OTHER	1,308	-	-	-	-	-	-	-	1,308
1823920	DSR COSTS AMORTIZED	103280	COMPANY INITIATIVES -PRODUCTION EFFICIEN	OTHER	388	-	-	-	-	-	-	-	388
1823920	DSR COSTS AMORTIZED	103291	Portfolio -WY-2011 Cat4	OTHER	266	-	-	-	-	-	-	-	266
1823920	DSR COSTS AMORTIZED	103292	Portfolio - Washington	OTHER	3,296	-	-	-	-	-	-	-	3,296
1823920	DSR COSTS AMORTIZED	103293	Energy Storage Demonstration Project -UT	OTHER	7	-	-	-	-	-	-	-	7
1823920	DSR COSTS AMORTIZED	103295	Outreach And Communication-WY-2011	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103299	AGRICULURAL FINANSWER EXPRESS - UTAH - 2	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103300	AGRICULTURAL FINANSWER EXPRESS - WASHING	OTHER	75	-	-	-	-	-	-	-	75
1823920	DSR COSTS AMORTIZED	103301	PORTFOLIO -WY-2011 CAT2	OTHER	74	-	-	-	-	-	-	-	74
1823920	DSR COSTS AMORTIZED	103302	PORTFOLIO -WY-2011 CAT3	OTHER	110	-	-	-	-	-	-	-	110
1823920	DSR COSTS AMORTIZED	103308	Home Energy Reporting -OPower -WA 2011	OTHER	1,292	-	-	-	-	-	-	-	1,292
1823920	DSR COSTS AMORTIZED	103311	CALIFORNIA DSM EXPENSE - 2012	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103324	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	5,794	-	-	-	-	-	-	-	5,794
1823920	DSR COSTS AMORTIZED	103325	AIR CONDITIONING - UTAH - 2012	OTHER	1,470	-	-	-	-	-	-	-	1,470
1823920	DSR COSTS AMORTIZED	103326	ENERGY FINANSWER - UTAH - 2012	OTHER	6,899	-	-	-	-	-	-	-	6,899
1823920	DSR COSTS AMORTIZED	103327	INDUSTRIAL FINANSWER - UTAH - 2012	OTHER	2,935	-	-	-	-	-	-	-	2,935
1823920	DSR COSTS AMORTIZED	103328	LOW INCOME - UTAH - 2012	OTHER	177	-	-	-	-	-	-	-	177
1823920	DSR COSTS AMORTIZED	103330	REFRIGERATOR RECYCLING PGM- UTAH - 2012	OTHER	1,474	-	-	-	-	-	-	-	1,474
1823920	DSR COSTS AMORTIZED	103331	COMMERCIAL SELF-DIRECT - UTAH - 2012	OTHER	172	-	-	-	-	-	-	-	172
1823920	DSR COSTS AMORTIZED	103332	INDUSTRIAL SELF-DIRECT - UTAH - 2012	OTHER	429	-	-	-	-	-	-	-	429
1823920	DSR COSTS AMORTIZED	103333	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,943	-	-	-	-	-	-	-	1,943
1823920	DSR COSTS AMORTIZED	103334	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	6,221	-	-	-	-	-	-	-	6,221
1823920	DSR COSTS AMORTIZED	103335	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,280	-	-	-	-	-	-	-	1,280
1823920	DSR COSTS AMORTIZED	103336	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	460	-	-	-	-	-	-	-	460
1823920	DSR COSTS AMORTIZED	103337	IRRIGATION LOAD CONTROL - UTAH - 2012	OTHER	2,097	-	-	-	-	-	-	-	2,097
1823920	DSR COSTS AMORTIZED	103338	HOME ENERGY EFF INCENTIVE PROG - UT 2012	OTHER	11,113	-	-	-	-	-	-	-	11,113
1823920	DSR COSTS AMORTIZED	103339	OUTREACH and COMMUNICATIONS - UT 2012	OTHER	1,836	-	-	-	-	-	-	-	1,836
1823920	DSR COSTS AMORTIZED	103340	COMMERCIAL DIRECT INSTALL - UT 2012	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103341	COMMERCIAL CURTAILMENT - UT 2012	OTHER	(30)	-	-	-	-	-	-	-	(30)
1823920	DSR COSTS AMORTIZED	103342	ENERGY STORAGE DEMO PROJECT - UT 2012	OTHER	6	-	-	-	-	-	-	-	6
1823920	DSR COSTS AMORTIZED	103343	AGRICULTURAL FINANSWER EXPRESS - UTAH -	OTHER	21	-	-	-	-	-	-	-	21

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-UPL + Wy-PPL	Utah	Id-PPL + Idaho	FERC	Other
1823920	DSR COSTS AMORTIZED	103346	HOME ENERGY REPORTING - UT 2012	OTHER	534	-	-	-	-	-	-	-	534
1823920	DSR COSTS AMORTIZED	103347	ENERGY FINANSWER-WY-2012 CAT3	OTHER	20	-	-	-	-	-	-	-	20
1823920	DSR COSTS AMORTIZED	103348	INDUSTRIAL FINANSWER-WY-2012 CAT3	OTHER	606	-	-	-	-	-	-	-	606
1823920	DSR COSTS AMORTIZED	103349	REFRIGERATOR RECYCLING-WY -2012 CAT1	OTHER	169	-	-	-	-	-	-	-	169
1823920	DSR COSTS AMORTIZED	103350	HOME ENERGY EFF INCENT PROG Y-2012 CAT1	OTHER	904	-	-	-	-	-	-	-	904
1823920	DSR COSTS AMORTIZED	103351	LOW-INCOME WEATHERZTN - WY 2012 CAT1	OTHER	31	-	-	-	-	-	-	-	31
1823920	DSR COSTS AMORTIZED	103352	COMMERCIAL FINANSWER EXP WY-2012 CAT3	OTHER	143	-	-	-	-	-	-	-	143
1823920	DSR COSTS AMORTIZED	103353	INDUSTRIAL FINANSWER EXP WY-2012 CAT3	OTHER	170	-	-	-	-	-	-	-	170
1823920	DSR COSTS AMORTIZED	103354	SELF DIRECT - COMMERCIAL -WY-2012 CAT3	OTHER	4	-	-	-	-	-	-	-	4
1823920	DSR COSTS AMORTIZED	103355	SELF DIRECT -INDUSTRIAL -WY-2012 CAT3	OTHER	60	-	-	-	-	-	-	-	60
1823920	DSR COSTS AMORTIZED	103356	COMMERCIAL FINANSWER EXP- WY-2012 CAT2	OTHER	1,203	-	-	-	-	-	-	-	1,203
1823920	DSR COSTS AMORTIZED	103357	INDUSTRIAL FINAN EXPRESS WY-2012 CAT2	OTHER	58	-	-	-	-	-	-	-	58
1823920	DSR COSTS AMORTIZED	103358	ENERGY FINANSWER -WY 2012 CAT2	OTHER	59	-	-	-	-	-	-	-	59
1823920	DSR COSTS AMORTIZED	103359	INDUSTRIAL FINANSWER -WY 2012 CAT2	OTHER	205	-	-	-	-	-	-	-	205
1823920	DSR COSTS AMORTIZED	103360	SELF DIRECT - COMMERCIAL WY-2012 CAT2	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103361	SELF DIRECT- INDUSTRIAL WY-2012 CAT2	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103363	PORTFOLIO WY-2012 CAT1	OTHER	33	-	-	-	-	-	-	-	33
1823920	DSR COSTS AMORTIZED	103364	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	155	-	-	-	-	-	-	-	155
1823920	DSR COSTS AMORTIZED	103365	AGRICULURAL FINANSWER EXP WY-2012 CAT2	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103366	AGRICULURAL FINANSWER EXP WY-2012 CAT3	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103367	PORTFOLIO WY-2012 CAT2	OTHER	35	-	-	-	-	-	-	-	35
1823920	DSR COSTS AMORTIZED	103368	PORTFOLIO WY-2012 CAT3	OTHER	30	-	-	-	-	-	-	-	30
1823920	DSR COSTS AMORTIZED	103369	COMMERCIAL CURTAILMENT - OR 2012	OTHER	(27)	-	-	-	-	-	-	-	(27)
1823920	DSR COSTS AMORTIZED	103493	U.of Utah Student Energy Sponsorship- UT	OTHER	8	-	-	-	-	-	-	-	8
1823920	DSR COSTS AMORTIZED	103496	PORTFOLIO - IDAHO	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103497	PORTFOLIO - UTAH	OTHER	42	-	-	-	-	-	-	-	42
1823920	DSR COSTS AMORTIZED	103623	CALIFORNIA DSM EXPENSE - 2013	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103646	PORTFOLIO - IDAHO 2013	OTHER	38	-	-	-	-	-	-	-	38
1823920	DSR COSTS AMORTIZED	103647	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	10,293	-	-	-	-	-	-	-	10,293
1823920	DSR COSTS AMORTIZED	103648	AIR CONDITIONING - UTAH - 2013	OTHER	66	-	-	-	-	-	-	-	66
1823920	DSR COSTS AMORTIZED	103649	ENERGY FINANSWER - UTAH - 2013	OTHER	1,445	-	-	-	-	-	-	-	1,445
1823920	DSR COSTS AMORTIZED	103650	INDUSTRIAL FINANSWER - UTAH - 2013	OTHER	2,168	-	-	-	-	-	-	-	2,168
1823920	DSR COSTS AMORTIZED	103651	LOW INCOME - UTAH - 2013	OTHER	120	-	-	-	-	-	-	-	120
1823920	DSR COSTS AMORTIZED	103653	REFRIGERATOR RECYCLING PGM- UTAH - 2013	OTHER	1,544	-	-	-	-	-	-	-	1,544
1823920	DSR COSTS AMORTIZED	103654	COMMERCIAL SELF-DIRECT - UTAH - 2013	OTHER	116	-	-	-	-	-	-	-	116
1823920	DSR COSTS AMORTIZED	103655	INDUSTRIAL SELF-DIRECT - UTAH - 2013	OTHER	319	-	-	-	-	-	-	-	319
1823920	DSR COSTS AMORTIZED	103656	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,314	-	-	-	-	-	-	-	1,314
1823920	DSR COSTS AMORTIZED	103657	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	8,290	-	-	-	-	-	-	-	8,290
1823920	DSR COSTS AMORTIZED	103658	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,444	-	-	-	-	-	-	-	1,444
1823920	DSR COSTS AMORTIZED	103660	IRRIGATION LOAD CONTROL - UTAH - 2013	OTHER	807	-	-	-	-	-	-	-	807
1823920	DSR COSTS AMORTIZED	103661	HOME ENERGY EFF INCENTIVE PROG - UT 2013	OTHER	20,269	-	-	-	-	-	-	-	20,269
1823920	DSR COSTS AMORTIZED	103662	OUTREACH and COMMUNICATIONS - UT 2013	OTHER	1,406	-	-	-	-	-	-	-	1,406
1823920	DSR COSTS AMORTIZED	103666	AGRICULTURAL FINANSWER EXPRESS - UTAH -	OTHER	70	-	-	-	-	-	-	-	70
1823920	DSR COSTS AMORTIZED	103671	HOME ENERGY REPORTING - UT 2013	OTHER	765	-	-	-	-	-	-	-	765
1823920	DSR COSTS AMORTIZED	103673	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	135	-	-	-	-	-	-	-	135
1823920	DSR COSTS AMORTIZED	103675	ENERGY FINANSWER-WY-2013 CAT3	OTHER	27	-	-	-	-	-	-	-	27
1823920	DSR COSTS AMORTIZED	103676	INDUSTRIAL FINANSWER-WY-2013 CAT3	OTHER	985	-	-	-	-	-	-	-	985
1823920	DSR COSTS AMORTIZED	103677	REFRIGERATOR RECYCLING-WY -2013 CAT1	OTHER	130	-	-	-	-	-	-	-	130
1823920	DSR COSTS AMORTIZED	103678	HOME ENERGY EFF INCENT PROG Y-2013 CAT1	OTHER	884	-	-	-	-	-	-	-	884
1823920	DSR COSTS AMORTIZED	103679	LOW-INCOME WEATHERZTN - WY 2013 CAT1	OTHER	41	-	-	-	-	-	-	-	41
1823920	DSR COSTS AMORTIZED	103680	COMMERCIAL FINANSWER EXP WY-2013 CAT3	OTHER	424	-	-	-	-	-	-	-	424
1823920	DSR COSTS AMORTIZED	103681	INDUSTRIAL FINANSWER EXP WY-2013 CAT3	OTHER	169	-	-	-	-	-	-	-	169
1823920	DSR COSTS AMORTIZED	103682	SELF DIRECT - COMMERCIAL -WY-2013 CAT3	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103683	SELF DIRECT -INDUSTRIAL -WY-2013 CAT3	OTHER	9	-	-	-	-	-	-	-	9
1823920	DSR COSTS AMORTIZED	103684	COMMERCIAL FINANSWER EXP- WY-2013 CAT2	OTHER	1,234	-	-	-	-	-	-	-	1,234
1823920	DSR COSTS AMORTIZED	103685	INDUSTRIAL FINAN EXPRESS WY-2013 CAT2	OTHER	85	-	-	-	-	-	-	-	85
1823920	DSR COSTS AMORTIZED	103686	ENERGY FINANSWER -WY 2013 CAT2	OTHER	26	-	-	-	-	-	-	-	26
1823920	DSR COSTS AMORTIZED	103687	INDUSTRIAL FINANSWER -WY 2013 CAT2	OTHER	58	-	-	-	-	-	-	-	58
1823920	DSR COSTS AMORTIZED	103688	SELF DIRECT - COMMERCIAL WY-2013 CAT2	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103689	SELF DIRECT- INDUSTRIAL WY-2013 CAT2	OTHER	8	-	-	-	-	-	-	-	8
1823920	DSR COSTS AMORTIZED	103690	PORTFOLIO WY-2013 CAT1	OTHER	130	-	-	-	-	-	-	-	130
1823920	DSR COSTS AMORTIZED	103691	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	178	-	-	-	-	-	-	-	178
1823920	DSR COSTS AMORTIZED	103692	AGRICULTURAL FINANSWER EXP WY-2013 CAT2	OTHER	10	-	-	-	-	-	-	-	10

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1823920	DSR COSTS AMORTIZED	103693	AGRICULURAL FINANSWER EXP WY-2013 CAT3	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103694	PORTFOLIO WY-2013 CAT2	OTHER	38	-	-	-	-	-	-	-	38
1823920	DSR COSTS AMORTIZED	103695	PORTFOLIO WY-2013 CAT3	OTHER	26	-	-	-	-	-	-	-	26
1823920	DSR COSTS AMORTIZED	103700	PORTFOLIO - UTAH 2013	OTHER	435	-	-	-	-	-	-	-	435
1823920	DSR COSTS AMORTIZED	103701	U.of Utah Student Energy Sponsorship- UT	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103732	COMMERCIAL (WSB) WATTSMART BUSINESS - UT	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103734	INDUSTRIAL (WSB) WATTSMART BUSINESS - UT	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103735	WSB - WATTSMART BUSINESS - UT- 2013	OTHER	12	-	-	-	-	-	-	-	12
1823920	DSR COSTS AMORTIZED	103740	COMMERCIAL (WSB) WATTSMART BUSINESS - WA	OTHER	5,435	-	-	-	-	-	-	-	5,435
1823920	DSR COSTS AMORTIZED	103741	INDUSTRIAL WATTSMART BUSINESS - WA-2013	OTHER	6,233	-	-	-	-	-	-	-	6,233
1823920	DSR COSTS AMORTIZED	103742	WSB - WATTSMART BUSINESS - WA- 2013	OTHER	4,049	-	-	-	-	-	-	-	4,049
1823920	DSR COSTS AMORTIZED	103743	AGRICULTURAL (WSB) WATTSMART BUSINESS -	OTHER	306	-	-	-	-	-	-	-	306
1823920	DSR COSTS AMORTIZED	103745	CALIFORNIA DSM EXPENSE - 2014	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103754	PORTFOLIO - IDAHO 2014	OTHER	30	-	-	-	-	-	-	-	30
1823920	DSR COSTS AMORTIZED	103756	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	24,564	-	-	-	-	-	-	-	24,564
1823920	DSR COSTS AMORTIZED	103757	AGRICULURAL FINANSWER EXPRESS - UTAH - 2	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103758	AIR CONDITIONING - UTAH - 2014	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103759	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	401	-	-	-	-	-	-	-	401
1823920	DSR COSTS AMORTIZED	103760	ENERGY FINANSWER - UTAH - 2014	OTHER	37	-	-	-	-	-	-	-	37
1823920	DSR COSTS AMORTIZED	103761	HOME ENERGY EFF INCENTIVE PROG - UT 2014	OTHER	24,908	-	-	-	-	-	-	-	24,908
1823920	DSR COSTS AMORTIZED	103762	HOME ENERGY REPORTING - UT 2014	OTHER	1,630	-	-	-	-	-	-	-	1,630
1823920	DSR COSTS AMORTIZED	103763	INDUSTRIAL FINANSWER - UTAH - 2014	OTHER	60	-	-	-	-	-	-	-	60
1823920	DSR COSTS AMORTIZED	103764	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	144	-	-	-	-	-	-	-	144
1823920	DSR COSTS AMORTIZED	103765	IRRIGATION LOAD CONTROL - UTAH - 2014	OTHER	597	-	-	-	-	-	-	-	597
1823920	DSR COSTS AMORTIZED	103766	LOW INCOME - UTAH - 2014	OTHER	170	-	-	-	-	-	-	-	170
1823920	DSR COSTS AMORTIZED	103767	OUTREACH and COMMUNICATIONS - UT 2014	OTHER	1,585	-	-	-	-	-	-	-	1,585
1823920	DSR COSTS AMORTIZED	103768	PORTFOLIO - UTAH 2014	OTHER	242	-	-	-	-	-	-	-	242
1823920	DSR COSTS AMORTIZED	103769	REFRIGERATOR RECYCLING PGM- UTAH - 2014	OTHER	1,762	-	-	-	-	-	-	-	1,762
1823920	DSR COSTS AMORTIZED	103770	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,203	-	-	-	-	-	-	-	1,203
1823920	DSR COSTS AMORTIZED	103771	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103772	COMMERCIAL SELF-DIRECT - UTAH - 2014	OTHER	29	-	-	-	-	-	-	-	29
1823920	DSR COSTS AMORTIZED	103773	INDUSTRIAL SELF-DIRECT - UTAH - 2014	OTHER	53	-	-	-	-	-	-	-	53
1823920	DSR COSTS AMORTIZED	103774	COMMERCIAL (WSB) WATTSMART BUS - UT- 201	OTHER	12,239	-	-	-	-	-	-	-	12,239
1823920	DSR COSTS AMORTIZED	103775	INDUSTRIAL (WSB) WATTSMART BUS- UT- 2014	OTHER	6,640	-	-	-	-	-	-	-	6,640
1823920	DSR COSTS AMORTIZED	103776	WSB - WATTSMART BUS- UT- 2014	OTHER	3,636	-	-	-	-	-	-	-	3,636
1823920	DSR COSTS AMORTIZED	103777	AGRICULTURAL (WSB) WATTSMART BUS- UT- 20	OTHER	161	-	-	-	-	-	-	-	161
1823920	DSR COSTS AMORTIZED	103778	U.of Utah Student Energy Sponsorship- UT	OTHER	5	-	-	-	-	-	-	-	5
1823920	DSR COSTS AMORTIZED	103779	AGRICULURAL FINANSWER EXP WY-2014 CAT2	OTHER	4	-	-	-	-	-	-	-	4
1823920	DSR COSTS AMORTIZED	103780	AGRICULURAL FINANSWER EXP WY-2014 CAT3	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103781	COMMERCIAL FINANSWER EXP- WY-2014 CAT2	OTHER	1,178	-	-	-	-	-	-	-	1,178
1823920	DSR COSTS AMORTIZED	103782	COMMERCIAL FINANSWER EXP WY-2014 CAT3	OTHER	255	-	-	-	-	-	-	-	255
1823920	DSR COSTS AMORTIZED	103783	ENERGY FINANSWER -WY 2014 CAT2	OTHER	32	-	-	-	-	-	-	-	32
1823920	DSR COSTS AMORTIZED	103784	ENERGY FINANSWER-WY-2014 CAT3	OTHER	71	-	-	-	-	-	-	-	71
1823920	DSR COSTS AMORTIZED	103785	HOME ENERGY EFF INCENT PROG Y-2014 CAT1	OTHER	1,183	-	-	-	-	-	-	-	1,183
1823920	DSR COSTS AMORTIZED	103786	INDUSTRIAL FINANSWER -WY 2014 CAT2	OTHER	95	-	-	-	-	-	-	-	95
1823920	DSR COSTS AMORTIZED	103787	INDUSTRIAL FINANSWER-WY-2014 CAT3	OTHER	356	-	-	-	-	-	-	-	356
1823920	DSR COSTS AMORTIZED	103788	INDUSTRIAL FINAN EXPRESS WY-2014 CAT2	OTHER	136	-	-	-	-	-	-	-	136
1823920	DSR COSTS AMORTIZED	103789	INDUSTRIAL FINANSWER EXP WY-2014 CAT3	OTHER	203	-	-	-	-	-	-	-	203
1823920	DSR COSTS AMORTIZED	103790	LOW-INCOME WEATHERZTN - WY 2014 CAT1	OTHER	30	-	-	-	-	-	-	-	30
1823920	DSR COSTS AMORTIZED	103791	OUTREACH AND COMMUNICATION WATTSMT WY-	OTHER	157	-	-	-	-	-	-	-	157
1823920	DSR COSTS AMORTIZED	103792	PORTFOLIO WY-2014 CAT1	OTHER	63	-	-	-	-	-	-	-	63
1823920	DSR COSTS AMORTIZED	103793	PORTFOLIO WY-2014 CAT2	OTHER	147	-	-	-	-	-	-	-	147
1823920	DSR COSTS AMORTIZED	103794	PORTFOLIO WY-2014 CAT3	OTHER	258	-	-	-	-	-	-	-	258
1823920	DSR COSTS AMORTIZED	103795	REFRIGERATOR RECYCLING-WY -2014 CAT1	OTHER	159	-	-	-	-	-	-	-	159
1823920	DSR COSTS AMORTIZED	103796	SELF DIRECT - COMMERCIAL WY-2014 CAT2	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103797	SELF DIRECT - COMMERCIAL -WY-2014 CAT3	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103798	SELF DIRECT- INDUSTRIAL WY-2014 CAT2	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103799	SELF DIRECT -INDUSTRIAL -WY-2014 CAT3	OTHER	198	-	-	-	-	-	-	-	198
1823920	DSR COSTS AMORTIZED	103805	WSB - WATTSMART BUSINESS - CA- 2014	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103808	WSB - WATTSMART BUSINESS - ID- 2014	OTHER	32	-	-	-	-	-	-	-	32
1823920	DSR COSTS AMORTIZED	103809	WSB Small Business Comm - ID-2014	OTHER	11	-	-	-	-	-	-	-	11
1823920	DSR COSTS AMORTIZED	103810	WSB Small Business Ind - ID 2014	OTHER	8	-	-	-	-	-	-	-	8
1823920	DSR COSTS AMORTIZED	103811	WSB - Wattsmart Business - WY Cat 2- 201	OTHER	26	-	-	-	-	-	-	-	26

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1823920	DSR COSTS AMORTIZED	103812	WSB - Small Business Comm - WY Cat2 -201	OTHER	7	-	-	-	-	-	-	-	7
1823920	DSR COSTS AMORTIZED	103813	WBS Small Business Ind - WY Cat2-2014	OTHER	5	-	-	-	-	-	-	-	5
1823920	DSR COSTS AMORTIZED	103814	WSB Small Business Comm- UT-2014	OTHER	1,635	-	-	-	-	-	-	-	1,635
1823920	DSR COSTS AMORTIZED	103815	WBS Small Business Ind- UT-2014	OTHER	23	-	-	-	-	-	-	-	23
1823920	DSR COSTS AMORTIZED	103816	WSB Small Business Comm- WA-2014	OTHER	557	-	-	-	-	-	-	-	557
1823920	DSR COSTS AMORTIZED	103817	WBS Small Business Ind- WA-2014	OTHER	46	-	-	-	-	-	-	-	46
1823920	DSR COSTS AMORTIZED	103834	HOME ENERGY REPORTING - ID 2014	OTHER	20	-	-	-	-	-	-	-	20
1823920	DSR COSTS AMORTIZED	103835	HOME ENERGY REPORTING - WY 2014	OTHER	23	-	-	-	-	-	-	-	23
1823920	DSR COSTS AMORTIZED	103845	REFRIGERATOR RECYCLING COMM - WASHINGTON	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103856	WSB Wattsmart Business Agric - ID-2014	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103858	WSB Wattsmart Business Comm- WY Cat3 -20	OTHER	8	-	-	-	-	-	-	-	8
1823920	DSR COSTS AMORTIZED	103859	WBS Wattsmart Business Ind- WY Cat2-2014	OTHER	26	-	-	-	-	-	-	-	26
1823920	DSR COSTS AMORTIZED	103860	WSB- Wattsmart Business- WY Cat 3- 2014	OTHER	5	-	-	-	-	-	-	-	5
1823920	DSR COSTS AMORTIZED	103862	OUTREACH AND COMMUNICATION ID-2014	OTHER	5	-	-	-	-	-	-	-	5
1823920	DSR COSTS AMORTIZED	103865	CALIFORNIA DSM EXPENSE - 2015	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103874	PORTFOLIO - IDAHO 2015	OTHER	23	-	-	-	-	-	-	-	23
1823920	DSR COSTS AMORTIZED	103876	WSB - WATTSMART BUSINESS - ID- 2015	OTHER	410	-	-	-	-	-	-	-	410
1823920	DSR COSTS AMORTIZED	103877	WSB Small Business Comm - ID-2015	OTHER	1,345	-	-	-	-	-	-	-	1,345
1823920	DSR COSTS AMORTIZED	103878	WSB Small Business Ind - ID 2015	OTHER	264	-	-	-	-	-	-	-	264
1823920	DSR COSTS AMORTIZED	103879	HOME ENERGY REPORTING - ID 2015	OTHER	136	-	-	-	-	-	-	-	136
1823920	DSR COSTS AMORTIZED	103880	WSB Wattsmart Business Agric - ID-2015	OTHER	227	-	-	-	-	-	-	-	227
1823920	DSR COSTS AMORTIZED	103881	OUTREACH AND COMMUNICATION ID-2015	OTHER	153	-	-	-	-	-	-	-	153
1823920	DSR COSTS AMORTIZED	103882	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	4,174	-	-	-	-	-	-	-	4,174
1823920	DSR COSTS AMORTIZED	103887	HOME ENERGY EFF INCENTIVE PROG - UT 2015	OTHER	18,922	-	-	-	-	-	-	-	18,922
1823920	DSR COSTS AMORTIZED	103888	HOME ENERGY REPORTING - UT 2015	OTHER	2,878	-	-	-	-	-	-	-	2,878
1823920	DSR COSTS AMORTIZED	103891	IRRIGATION LOAD CONTROL - UTAH - 2015	OTHER	476	-	-	-	-	-	-	-	476
1823920	DSR COSTS AMORTIZED	103892	LOW INCOME - UTAH - 2015	OTHER	64	-	-	-	-	-	-	-	64
1823920	DSR COSTS AMORTIZED	103893	OUTREACH and COMMUNICATIONS - UT 2015	OTHER	1,611	-	-	-	-	-	-	-	1,611
1823920	DSR COSTS AMORTIZED	103894	PORTFOLIO - UTAH 2015	OTHER	370	-	-	-	-	-	-	-	370
1823920	DSR COSTS AMORTIZED	103895	REFRIGERATOR RECYCLING PGM- UTAH - 2015	OTHER	1,125	-	-	-	-	-	-	-	1,125
1823920	DSR COSTS AMORTIZED	103896	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,890	-	-	-	-	-	-	-	1,890
1823920	DSR COSTS AMORTIZED	103900	COMMERCIAL (WSB) WATTSMART BUS - UT- 201	OTHER	15,213	-	-	-	-	-	-	-	15,213
1823920	DSR COSTS AMORTIZED	103901	INDUSTRIAL (WSB) WATTSMART BUS- UT- 2015	OTHER	6,316	-	-	-	-	-	-	-	6,316
1823920	DSR COSTS AMORTIZED	103902	WSB - WATTSMART BUS- UT- 2015	OTHER	4,777	-	-	-	-	-	-	-	4,777
1823920	DSR COSTS AMORTIZED	103903	AGRICULTURAL (WSB) WATTSMART BUS- UT- 20	OTHER	257	-	-	-	-	-	-	-	257
1823920	DSR COSTS AMORTIZED	103904	U.of Utah Student Energy Sponsorship- UT	OTHER	6	-	-	-	-	-	-	-	6
1823920	DSR COSTS AMORTIZED	103905	WSB Small Business Comm- UT-2015	OTHER	3,896	-	-	-	-	-	-	-	3,896
1823920	DSR COSTS AMORTIZED	103906	WBS Small Business Ind- UT-2015	OTHER	262	-	-	-	-	-	-	-	262
1823920	DSR COSTS AMORTIZED	103907	AGRICULURAL FINANSWER EXP WY-2015 CAT2	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103909	COMMERCIAL FINANSWER EXP- WY-2015 CAT2	OTHER	97	-	-	-	-	-	-	-	97
1823920	DSR COSTS AMORTIZED	103910	COMMERCIAL FINANSWER EXP WY-2015 CAT3	OTHER	54	-	-	-	-	-	-	-	54
1823920	DSR COSTS AMORTIZED	103911	ENERGY FINANSWER -WY 2015 CAT2	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103912	ENERGY FINANSWER-WY-2015 CAT3	OTHER	43	-	-	-	-	-	-	-	43
1823920	DSR COSTS AMORTIZED	103913	HOME ENERGY EFF INCENT PROG Y-2015 CAT1	OTHER	1,207	-	-	-	-	-	-	-	1,207
1823920	DSR COSTS AMORTIZED	103914	INDUSTRIAL FINANSWER -WY 2015 CAT2	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103915	INDUSTRIAL FINANSWER-WY-2015 CAT3	OTHER	85	-	-	-	-	-	-	-	85
1823920	DSR COSTS AMORTIZED	103916	INDUSTRIAL FINAN EXPRESS WY-2015 CAT2	OTHER	9	-	-	-	-	-	-	-	9
1823920	DSR COSTS AMORTIZED	103917	INDUSTRIAL FINANSWER EXP WY-2015 CAT3	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	103918	LOW-INCOME WEATHERZTN - WY 2015 CAT1	OTHER	30	-	-	-	-	-	-	-	30
1823920	DSR COSTS AMORTIZED	103919	OUTREACH AND COMMUNICATION WATTSMT WY-	OTHER	121	-	-	-	-	-	-	-	121
1823920	DSR COSTS AMORTIZED	103920	PORTFOLIO WY-2015 CAT1	OTHER	71	-	-	-	-	-	-	-	71
1823920	DSR COSTS AMORTIZED	103921	PORTFOLIO WY-2015 CAT2	OTHER	29	-	-	-	-	-	-	-	29
1823920	DSR COSTS AMORTIZED	103922	PORTFOLIO WY-2015 CAT3	OTHER	47	-	-	-	-	-	-	-	47
1823920	DSR COSTS AMORTIZED	103923	REFRIGERATOR RECYCLING-WY -2015 CAT1	OTHER	99	-	-	-	-	-	-	-	99
1823920	DSR COSTS AMORTIZED	103925	SELF DIRECT - COMMERCIAL -WY-2015 CAT3	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103927	SELF DIRECT -INDUSTRIAL -WY-2015 CAT3	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103928	WSB - Wattsmart Business - WY Cat 2- 201	OTHER	639	-	-	-	-	-	-	-	639
1823920	DSR COSTS AMORTIZED	103929	WSB - Small Business Comm - WY Cat2 -201	OTHER	1,071	-	-	-	-	-	-	-	1,071
1823920	DSR COSTS AMORTIZED	103930	WBS- Wattsmart Business Ind -WY Cat2-201	OTHER	286	-	-	-	-	-	-	-	286
1823920	DSR COSTS AMORTIZED	103931	HOME ENERGY REPORTING - WY 2015	OTHER	139	-	-	-	-	-	-	-	139
1823920	DSR COSTS AMORTIZED	103932	WSB- Wattsmart Business- WY Cat 3- 2015	OTHER	178	-	-	-	-	-	-	-	178
1823920	DSR COSTS AMORTIZED	103933	REFRIG RECYCLE COMM -WY 2015 CAT2	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103934	REFRIG RECYCLE COMM -WY 2015 CAT3	OTHER	1	-	-	-	-	-	-	-	1

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-UPL + Wy-PPL	Utah	Id-PPL + Idaho	FERC	Other
1823920	DSR COSTS AMORTIZED	103935	WSB Wattsmart Business Comm- WY Cat3 -20	OTHER	381	-	-	-	-	-	-	-	381
1823920	DSR COSTS AMORTIZED	103936	WBS- Wattsmart Bus Ind- WY Cat3-2015	OTHER	1,487	-	-	-	-	-	-	-	1,487
1823920	DSR COSTS AMORTIZED	103937	WSB- Wattsmart Business Agric- WY Cat2 -	OTHER	18	-	-	-	-	-	-	-	18
1823920	DSR COSTS AMORTIZED	103938	WSB- Wattsmart Business Agric- WY Cat3 -	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103959	COMMERCIAL ENERGY REPORTS-SMB -UT 2015	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	103962	Portfolio - EM&V C&I - ID- 2015	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103963	Portfolio - EM&V RES - ID- 2015	OTHER	41	-	-	-	-	-	-	-	41
1823920	DSR COSTS AMORTIZED	104013	CALIFORNIA DSM EXPENSE - 2016	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	104015	HOME ENERGY REPORTING - ID 2016	OTHER	94	-	-	-	-	-	-	-	94
1823920	DSR COSTS AMORTIZED	104018	OUTREACH AND COMMUNICATION ID-2016	OTHER	98	-	-	-	-	-	-	-	98
1823920	DSR COSTS AMORTIZED	104019	PORTFOLIO - IDAHO 2016	OTHER	6	-	-	-	-	-	-	-	6
1823920	DSR COSTS AMORTIZED	104020	Portfolio - EM&V C&I - ID- 2016	OTHER	166	-	-	-	-	-	-	-	166
1823920	DSR COSTS AMORTIZED	104021	Portfolio - EM&V RES - ID- 2016	OTHER	165	-	-	-	-	-	-	-	165
1823920	DSR COSTS AMORTIZED	104023	WSB Small Business Comm - ID-2016	OTHER	1,392	-	-	-	-	-	-	-	1,392
1823920	DSR COSTS AMORTIZED	104024	WSB Small Business Ind - ID 2016	OTHER	220	-	-	-	-	-	-	-	220
1823920	DSR COSTS AMORTIZED	104025	WSB - WATTSMART BUSINESS - ID- 2016	OTHER	607	-	-	-	-	-	-	-	607
1823920	DSR COSTS AMORTIZED	104026	WSB Wattsmart Business Agric - ID-2016	OTHER	311	-	-	-	-	-	-	-	311
1823920	DSR COSTS AMORTIZED	104027	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	4,957	-	-	-	-	-	-	-	4,957
1823920	DSR COSTS AMORTIZED	104029	HOME ENERGY EFF INCENTIVE PROG - UT 2016	OTHER	12,572	-	-	-	-	-	-	-	12,572
1823920	DSR COSTS AMORTIZED	104030	HOME ENERGY REPORTING - UT 2016	OTHER	2,335	-	-	-	-	-	-	-	2,335
1823920	DSR COSTS AMORTIZED	104031	IRRIGATION LOAD CONTROL - UTAH - 2016	OTHER	430	-	-	-	-	-	-	-	430
1823920	DSR COSTS AMORTIZED	104032	LOW INCOME - UTAH - 2016	OTHER	59	-	-	-	-	-	-	-	59
1823920	DSR COSTS AMORTIZED	104033	OUTREACH and COMMUNICATIONS - UT 2016	OTHER	1,313	-	-	-	-	-	-	-	1,313
1823920	DSR COSTS AMORTIZED	104034	PORTFOLIO - UTAH 2016	OTHER	164	-	-	-	-	-	-	-	164
1823920	DSR COSTS AMORTIZED	104035	REFRIGERATOR RECYCLING PGM- UTAH - 2016	OTHER	182	-	-	-	-	-	-	-	182
1823920	DSR COSTS AMORTIZED	104036	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,565	-	-	-	-	-	-	-	1,565
1823920	DSR COSTS AMORTIZED	104037	COMMERCIAL (WSB) WATTSMART BUS - UT- 201	OTHER	20,226	-	-	-	-	-	-	-	20,226
1823920	DSR COSTS AMORTIZED	104038	INDUSTRIAL (WSB) WATTSMART BUS- UT- 2016	OTHER	10,333	-	-	-	-	-	-	-	10,333
1823920	DSR COSTS AMORTIZED	104039	WSB Small Business Comm- UT-2016	OTHER	114	-	-	-	-	-	-	-	114
1823920	DSR COSTS AMORTIZED	104041	WSB - WATTSMART BUS- UT- 2016	OTHER	5,308	-	-	-	-	-	-	-	5,308
1823920	DSR COSTS AMORTIZED	104042	AGRICULTURAL (WSB) WATTSMART BUS- UT- 20	OTHER	1,099	-	-	-	-	-	-	-	1,099
1823920	DSR COSTS AMORTIZED	104043	U.of Utah Student Energy Sponsorship- UT	OTHER	5	-	-	-	-	-	-	-	5
1823920	DSR COSTS AMORTIZED	104044	HOME ENERGY REPORTING - WY 2016	OTHER	94	-	-	-	-	-	-	-	94
1823920	DSR COSTS AMORTIZED	104045	HOME ENERGY EFF INCENT PROG Y-2016 CAT1	OTHER	659	-	-	-	-	-	-	-	659
1823920	DSR COSTS AMORTIZED	104046	LOW-INCOME WEATHERZTN - WY 2016 CAT1	OTHER	14	-	-	-	-	-	-	-	14
1823920	DSR COSTS AMORTIZED	104047	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	79	-	-	-	-	-	-	-	79
1823920	DSR COSTS AMORTIZED	104048	PORTFOLIO WY-2016 CAT1	OTHER	131	-	-	-	-	-	-	-	131
1823920	DSR COSTS AMORTIZED	104049	PORTFOLIO WY-2016 CAT2	OTHER	37	-	-	-	-	-	-	-	37
1823920	DSR COSTS AMORTIZED	104050	PORTFOLIO WY-2016 CAT3	OTHER	45	-	-	-	-	-	-	-	45
1823920	DSR COSTS AMORTIZED	104051	REFRIGERATOR RECYCLING-WY -2016 CAT1	OTHER	16	-	-	-	-	-	-	-	16
1823920	DSR COSTS AMORTIZED	104052	REFRIG RECYCLE COMM -WY 2016 CAT2	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	104053	REFRIG RECYCLE COMM -WY 2016 CAT3	OTHER	(1)	-	-	-	-	-	-	-	(1)
1823920	DSR COSTS AMORTIZED	104054	WSB- Wattsmart Bus Comm- WY Cat2 -2016	OTHER	1,449	-	-	-	-	-	-	-	1,449
1823920	DSR COSTS AMORTIZED	104055	WBS- Wattsmart Business Ind -WY Cat2-201	OTHER	193	-	-	-	-	-	-	-	193
1823920	DSR COSTS AMORTIZED	104056	WSB - Wattsmart Business - WY Cat 2- 201	OTHER	912	-	-	-	-	-	-	-	912
1823920	DSR COSTS AMORTIZED	104057	WSB Wattsmart Business Comm- WY Cat3 -20	OTHER	467	-	-	-	-	-	-	-	467
1823920	DSR COSTS AMORTIZED	104058	WBS- Wattsmart Bus Ind- WY Cat3-2016	OTHER	1,239	-	-	-	-	-	-	-	1,239
1823920	DSR COSTS AMORTIZED	104059	WSB- Wattsmart Business Agric- WY Cat2 -	OTHER	4	-	-	-	-	-	-	-	4
1823920	DSR COSTS AMORTIZED	104060	WSB- Wattsmart Business Agric- WY Cat3 -	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	104061	WSB- Wattsmart Business- WY Cat 3- 2016	OTHER	602	-	-	-	-	-	-	-	602
1823920	DSR COSTS AMORTIZED	104080	OUTREACH & COMM WATTSMT WY-2016 CAT2	OTHER	44	-	-	-	-	-	-	-	44
1823920	DSR COSTS AMORTIZED	104081	OUTREACH & COMM WATTSMT WY-2016 CAT3	OTHER	42	-	-	-	-	-	-	-	42
1823920	DSR COSTS AMORTIZED	104109	WA DSM - 186055 Clear Acct Balance	OTHER	(841)	-	-	-	-	-	-	-	(841)
1823920	DSR COSTS AMORTIZED	104110	ID DSM - 186025 Clear Acct Balance	OTHER	398	-	-	-	-	-	-	-	398
1823920	DSR COSTS AMORTIZED	104111	WY DSM - 186065 Clear Acct Balance	OTHER	(1,405)	-	-	-	-	-	-	-	(1,405)
1823920 Total					**544,395**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**544,395**
1823930	DSR COSTS NOT AMORT	102573	ENERGY FINANSWER ID/UT 2006	OTHER	0	-	-	-	-	-	-	-	0
1823930	DSR COSTS NOT AMORT	102574	INDUSTRIAL FINANSWER-ID-UT 2006	OTHER	3	-	-	-	-	-	-	-	3
1823930	DSR COSTS NOT AMORT	102575	LOW INCOME WZ -ID-UT 2006	OTHER	144	-	-	-	-	-	-	-	144
1823930	DSR COSTS NOT AMORT	102576	NEEA-IDAHO-UTAH 2006	OTHER	359	-	-	-	-	-	-	-	359
1823930	DSR COSTS NOT AMORT	102577	IRRIGATION INTERRUPTIBLE ID-UT 2006	OTHER	361	-	-	-	-	-	-	-	361
1823930	DSR COSTS NOT AMORT	102578	WEATHERIZATION LOANS-RESDL/ID-UT 2006	OTHER	2	-	-	-	-	-	-	-	2
1823930	DSR COSTS NOT AMORT	102579	REFRIGERATOR RECYCLING PGM-ID-UT 2006	OTHER	143	-	-	-	-	-	-	-	143

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1823930	DSR COSTS NOT AMORT	102580	COMMERCIAL FINANSWER EXPR-ID-UT 2006	OTHER	117	-	-	-	-	-	-	-	117
1823930	DSR COSTS NOT AMORT	102581	INDUSTRIAL FINANSWER EXPR-ID-UT 2006	OTHER	47	-	-	-	-	-	-	-	47
1823930	DSR COSTS NOT AMORT	102582	IRRIGATION EFFICIENCY PRGRM-ID-UT 2006	OTHER	246	-	-	-	-	-	-	-	246
1823930	DSR COSTS NOT AMORT	102758	HOME ENERGY EFFICIENCY INCENTIVE PROGM-I	OTHER	103	-	-	-	-	-	-	-	103
1823930	DSR COSTS NOT AMORT	102808	WEATHERIZATION LOANS RESIDTL/ ID-UT 2007	OTHER	0	-	-	-	-	-	-	-	0
1823930	DSR COSTS NOT AMORT	102809	ENERGY FINANSWER IDU 2007	OTHER	4	-	-	-	-	-	-	-	4
1823930	DSR COSTS NOT AMORT	102810	Industrial Finanswer ID - 2007	OTHER	0	-	-	-	-	-	-	-	0
1823930	DSR COSTS NOT AMORT	102811	IRRIGATION INTERRUPTIBLE ID-UT 2007	OTHER	846	-	-	-	-	-	-	-	846
1823930	DSR COSTS NOT AMORT	102812	LOW INCOME WZ - ID-UT 2007	OTHER	101	-	-	-	-	-	-	-	101
1823930	DSR COSTS NOT AMORT	102813	NEEA - IDAHO - UTAH 2007	OTHER	361	-	-	-	-	-	-	-	361
1823930	DSR COSTS NOT AMORT	102814	REFRIGERATOR RECYCLING PGM - ID-UT 2007	OTHER	123	-	-	-	-	-	-	-	123
1823930	DSR COSTS NOT AMORT	102815	COMMERCIAL FINANSWER EXPR - ID-UT 2007	OTHER	61	-	-	-	-	-	-	-	61
1823930	DSR COSTS NOT AMORT	102816	INDUSTRIAL FINANSWER EXPR - ID-UT 2007	OTHER	120	-	-	-	-	-	-	-	120
1823930	DSR COSTS NOT AMORT	102817	IRRIGATION EFFICIENCY PRGRM - ID-UT 2007	OTHER	275	-	-	-	-	-	-	-	275
1823930	DSR COSTS NOT AMORT	102818	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	229	-	-	-	-	-	-	-	229
1823930	DSR COSTS NOT AMORT	102896	ENERGY FINANSWER - ID/UT 2008	OTHER	19	-	-	-	-	-	-	-	19
1823930	DSR COSTS NOT AMORT	102897	INDUSTRIAL FINANSWER - ID-UT 2008	OTHER	102	-	-	-	-	-	-	-	102
1823930	DSR COSTS NOT AMORT	102898	IRRIGATION INTERRUPTIBLE - IDAHO - 2008	OTHER	3,127	-	-	-	-	-	-	-	3,127
1823930	DSR COSTS NOT AMORT	102899	LOW INCOME WEATHERIZATION - IDAHO 2008	OTHER	165	-	-	-	-	-	-	-	165
1823930	DSR COSTS NOT AMORT	102900	NEEA - IDAHO - 2008	OTHER	317	-	-	-	-	-	-	-	317
1823930	DSR COSTS NOT AMORT	102901	REFRIGERATOR RECYCLING PRGM - IDAHO 2008	OTHER	113	-	-	-	-	-	-	-	113
1823930	DSR COSTS NOT AMORT	102902	COMMERCIAL FINANSWER EXPRESS - IDAHO 200	OTHER	108	-	-	-	-	-	-	-	108
1823930	DSR COSTS NOT AMORT	102903	INDUSTRIAL FINANSWER - IDAHO - 2008	OTHER	58	-	-	-	-	-	-	-	58
1823930	DSR COSTS NOT AMORT	102904	IRRIGATION EFFICIENCY PRGM - IDAHO - 200	OTHER	268	-	-	-	-	-	-	-	268
1823930	DSR COSTS NOT AMORT	102905	HOME ENERGY EFF INCENTIVE PROGRAM - IDAH	OTHER	490	-	-	-	-	-	-	-	490
1823930	DSR COSTS NOT AMORT	102957	CATEGORY 1 - WYOMING - 2008	OTHER	17	-	-	-	-	-	-	-	17
1823930	DSR COSTS NOT AMORT	102958	CATEGORY 2 - WYOMING - 2008	OTHER	9	-	-	-	-	-	-	-	9
1823930	DSR COSTS NOT AMORT	102959	CATEGORY 3 - WYOMING - 2008	OTHER	33	-	-	-	-	-	-	-	33
1823930	DSR COSTS NOT AMORT	102966	ENERGY FINANSWER - ID/UT 2009	OTHER	50	-	-	-	-	-	-	-	50
1823930	DSR COSTS NOT AMORT	102967	INDUSTRIAL FINANSWER - ID-UT 2009	OTHER	309	-	-	-	-	-	-	-	309
1823930	DSR COSTS NOT AMORT	102968	IRRIGATION INTERRUPTIBLE ID-UT 2009	OTHER	3,816	-	-	-	-	-	-	-	3,816
1823930	DSR COSTS NOT AMORT	102969	LOW INCOME WZ - ID-UT 2009	OTHER	198	-	-	-	-	-	-	-	198
1823930	DSR COSTS NOT AMORT	102970	NEEA - IDAHO - UTAH 2009	OTHER	287	-	-	-	-	-	-	-	287
1823930	DSR COSTS NOT AMORT	102971	REFRIGERATOR RECYCLING PGM - ID-UT 2009	OTHER	108	-	-	-	-	-	-	-	108
1823930	DSR COSTS NOT AMORT	102972	COMMERCIAL FINANSWER EXPR - ID-UT 2009	OTHER	190	-	-	-	-	-	-	-	190
1823930	DSR COSTS NOT AMORT	102973	INDUSTRIAL FINANSWER EXPR - ID-UT 2009	OTHER	74	-	-	-	-	-	-	-	74
1823930	DSR COSTS NOT AMORT	102974	IRRIGATION EFFICIENCY PRGRM - ID-UT 2009	OTHER	807	-	-	-	-	-	-	-	807
1823930	DSR COSTS NOT AMORT	102975	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	594	-	-	-	-	-	-	-	594
1823930	DSR COSTS NOT AMORT	103061	ENERGY FINANSWER - ID/UT 2010	OTHER	47	-	-	-	-	-	-	-	47
1823930	DSR COSTS NOT AMORT	103062	INDUSTRIAL FINANSWER - ID-UT 2010	OTHER	322	-	-	-	-	-	-	-	322
1823930	DSR COSTS NOT AMORT	103063	IRRIGATION INTERRUPTIBLE ID-UT 2010	OTHER	4,283	-	-	-	-	-	-	-	4,283
1823930	DSR COSTS NOT AMORT	103064	LOW INCOME WZ - ID-UT 2010	OTHER	134	-	-	-	-	-	-	-	134
1823930	DSR COSTS NOT AMORT	103065	NEEA - IDAHO - UTAH 2010	OTHER	0	-	-	-	-	-	-	-	0
1823930	DSR COSTS NOT AMORT	103066	REFRIGERATOR RECYCLING PGM - ID-UT 2010	OTHER	166	-	-	-	-	-	-	-	166
1823930	DSR COSTS NOT AMORT	103067	COMMERCIAL FINANSWER EXPR - ID-UT 2010	OTHER	513	-	-	-	-	-	-	-	513
1823930	DSR COSTS NOT AMORT	103068	INDUSTRIAL FINANSWER EXPR - ID-UT 2010	OTHER	107	-	-	-	-	-	-	-	107
1823930	DSR COSTS NOT AMORT	103069	IRRIGATION EFFICIENCY PRGRM - ID-UT 2010	OTHER	637	-	-	-	-	-	-	-	637
1823930	DSR COSTS NOT AMORT	103070	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	1,305	-	-	-	-	-	-	-	1,305
1823930	DSR COSTS NOT AMORT	103171	ENERGY FINANSWER - ID/UT 2011	OTHER	23	-	-	-	-	-	-	-	23
1823930	DSR COSTS NOT AMORT	103172	INDUSTRIAL FINANSWER - ID-UT 2011	OTHER	143	-	-	-	-	-	-	-	143
1823930	DSR COSTS NOT AMORT	103173	IRRIGATION INTERRUPTIBLE ID-UT 2011	OTHER	37	-	-	-	-	-	-	-	37
1823930	DSR COSTS NOT AMORT	103174	LOW INCOME WZ - ID-UT 2011	OTHER	425	-	-	-	-	-	-	-	425
1823930	DSR COSTS NOT AMORT	103176	REFRIGERATOR RECYCLING PGM - ID-UT 2011	OTHER	126	-	-	-	-	-	-	-	126
1823930	DSR COSTS NOT AMORT	103177	COMMERCIAL FINANSWER EXPR - ID-UT 2011	OTHER	632	-	-	-	-	-	-	-	632
1823930	DSR COSTS NOT AMORT	103178	INDUSTRIAL FINANSWER EXPR - ID-UT 2011	OTHER	77	-	-	-	-	-	-	-	77
1823930	DSR COSTS NOT AMORT	103179	IRRIGATION EFFICIENCY PRGRM - ID-UT 2011	OTHER	508	-	-	-	-	-	-	-	508
1823930	DSR COSTS NOT AMORT	103180	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	699	-	-	-	-	-	-	-	699
1823930	DSR COSTS NOT AMORT	103312	ENERGY FINANSWER - ID 2012	OTHER	35	-	-	-	-	-	-	-	35
1823930	DSR COSTS NOT AMORT	103313	INDUSTRIAL FINANSWER - ID 2012	OTHER	303	-	-	-	-	-	-	-	303
1823930	DSR COSTS NOT AMORT	103314	IRRIGATION INTERRUPTIBLE- ID 2012	OTHER	44	-	-	-	-	-	-	-	44
1823930	DSR COSTS NOT AMORT	103315	LOW INCOME WZ - ID- 2012	OTHER	296	-	-	-	-	-	-	-	296
1823930	DSR COSTS NOT AMORT	103317	REFRIGERATOR RECYCLING PGM - ID 2012	OTHER	115	-	-	-	-	-	-	-	115
1823930	DSR COSTS NOT AMORT	103318	COMMERCIAL FINANSWER EXPR - ID 2012	OTHER	706	-	-	-	-	-	-	-	706

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-UPL + Wy-PPL	Utah	Id-PPL + Idaho	FERC	Other
1823930	DSR COSTS NOT AMORT	103319	INDUSTRIAL FINANSWER EXPR - ID 2012	OTHER	226	-	-	-	-	-	-	-	226
1823930	DSR COSTS NOT AMORT	103320	IRRIGATION EFFICIENCY PRGRM - ID 2012	OTHER	847	-	-	-	-	-	-	-	847
1823930	DSR COSTS NOT AMORT	103321	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	789	-	-	-	-	-	-	-	789
1823930	DSR COSTS NOT AMORT	103322	COMMERCIAL DIRECT INSTALL - ID 2012	OTHER	0	-	-	-	-	-	-	-	0
1823930	DSR COSTS NOT AMORT	103323	AGRICULURAL FINANSWER EXPR - ID 2012	OTHER	7	-	-	-	-	-	-	-	7
1823930	DSR COSTS NOT AMORT	103398	RECOMMISSIONING INDUSTRIAL - UT 2012	OTHER	6	-	-	-	-	-	-	-	6
1823930	DSR COSTS NOT AMORT	103634	AGRICULURAL FINANSWER EXPR - ID 2013	OTHER	21	-	-	-	-	-	-	-	21
1823930	DSR COSTS NOT AMORT	103635	ENERGY FINANSWER - ID 2013	OTHER	77	-	-	-	-	-	-	-	77
1823930	DSR COSTS NOT AMORT	103636	INDUSTRIAL FINANSWER - ID 2013	OTHER	294	-	-	-	-	-	-	-	294
1823930	DSR COSTS NOT AMORT	103638	LOW INCOME WZ - ID- 2013	OTHER	226	-	-	-	-	-	-	-	226
1823930	DSR COSTS NOT AMORT	103640	REFRIGERATOR RECYCLING PGM - ID 2013	OTHER	115	-	-	-	-	-	-	-	115
1823930	DSR COSTS NOT AMORT	103641	COMMERCIAL FINANSWER EXPR - ID 2013	OTHER	615	-	-	-	-	-	-	-	615
1823930	DSR COSTS NOT AMORT	103642	INDUSTRIAL FINANSWER EXPR - ID 2013	OTHER	363	-	-	-	-	-	-	-	363
1823930	DSR COSTS NOT AMORT	103643	IRRIGATION EFFICIENCY PRGRM - ID 2013	OTHER	1,222	-	-	-	-	-	-	-	1,222
1823930	DSR COSTS NOT AMORT	103644	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	844	-	-	-	-	-	-	-	844
1823930	DSR COSTS NOT AMORT	103672	RECOMMISSIONING INDUSTRIAL - UT 2013	OTHER	58	-	-	-	-	-	-	-	58
1823930	DSR COSTS NOT AMORT	103746	AGRICULURAL FINANSWER EXPR - ID 2014	OTHER	122	-	-	-	-	-	-	-	122
1823930	DSR COSTS NOT AMORT	103747	COMMERCIAL FINANSWER EXPR - ID 2014	OTHER	683	-	-	-	-	-	-	-	683
1823930	DSR COSTS NOT AMORT	103748	ENERGY FINANSWER - ID 2014	OTHER	154	-	-	-	-	-	-	-	154
1823930	DSR COSTS NOT AMORT	103749	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	854	-	-	-	-	-	-	-	854
1823930	DSR COSTS NOT AMORT	103750	INDUSTRIAL FINANSWER - ID 2014	OTHER	105	-	-	-	-	-	-	-	105
1823930	DSR COSTS NOT AMORT	103751	INDUSTRIAL FINANSWER EXPR - ID 2014	OTHER	268	-	-	-	-	-	-	-	268
1823930	DSR COSTS NOT AMORT	103752	IRRIGATION EFFICIENCY PRGRM - ID 2014	OTHER	449	-	-	-	-	-	-	-	449
1823930	DSR COSTS NOT AMORT	103753	LOW INCOME WZ - ID- 2014	OTHER	298	-	-	-	-	-	-	-	298
1823930	DSR COSTS NOT AMORT	103755	REFRIGERATOR RECYCLING PGM - ID 2014	OTHER	122	-	-	-	-	-	-	-	122
1823930	DSR COSTS NOT AMORT	103866	AGRICULURAL FINANSWER EXPR - ID 2015	OTHER	2	-	-	-	-	-	-	-	2
1823930	DSR COSTS NOT AMORT	103867	COMMERCIAL FINANSWER EXPR - ID 2015	OTHER	157	-	-	-	-	-	-	-	157
1823930	DSR COSTS NOT AMORT	103868	ENERGY FINANSWER - ID 2015	OTHER	6	-	-	-	-	-	-	-	6
1823930	DSR COSTS NOT AMORT	103869	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	848	-	-	-	-	-	-	-	848
1823930	DSR COSTS NOT AMORT	103870	INDUSTRIAL FINANSWER - ID 2015	OTHER	63	-	-	-	-	-	-	-	63
1823930	DSR COSTS NOT AMORT	103871	INDUSTRIAL FINANSWER EXPR - ID 2015	OTHER	80	-	-	-	-	-	-	-	80
1823930	DSR COSTS NOT AMORT	103872	IRRIGATION EFFICIENCY PRGRM - ID 2015	OTHER	236	-	-	-	-	-	-	-	236
1823930	DSR COSTS NOT AMORT	103873	LOW INCOME WZ - ID- 2015	OTHER	296	-	-	-	-	-	-	-	296
1823930	DSR COSTS NOT AMORT	103875	REFRIGERATOR RECYCLING PGM - ID 2015	OTHER	106	-	-	-	-	-	-	-	106
1823930	DSR COSTS NOT AMORT	104014	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	450	-	-	-	-	-	-	-	450
1823930	DSR COSTS NOT AMORT	104016	IRRIGATION EFFICIENCY PRGRM - ID 2016	OTHER	80	-	-	-	-	-	-	-	80
1823930	DSR COSTS NOT AMORT	104017	LOW INCOME WZ - ID- 2016	OTHER	245	-	-	-	-	-	-	-	245
1823930	DSR COSTS NOT AMORT	104022	REFRIGERATOR RECYCLING PGM - ID 2016	OTHER	14	-	-	-	-	-	-	-	14
1823930 Total					**37,937**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**37,937**
1823940	DSR CARRYING CHARGES	102146	UT CARRYING CHARGE - 2001/2002	OTHER	3,457	-	-	-	-	-	-	-	3,457
1823940	DSR CARRYING CHARGES	102188	WA REVENUE RECOVERY - CARRYING CHG PENAL	OTHER	(680)	-	-	-	-	-	-	-	(680)
1823940	DSR CARRYING CHARGES	102766	DSR CARRYING CHARGES	OTHER	163	-	-	-	-	-	-	-	163
1823940	DSR CARRYING CHARGES	103140	Wy DSM - Cat1 - Carrying Charges	OTHER	(102)	-	-	-	-	-	-	-	(102)
1823940	DSR CARRYING CHARGES	103141	Wy DSM - Cat2 - Carrying Charges	OTHER	(34)	-	-	-	-	-	-	-	(34)
1823940	DSR CARRYING CHARGES	103142	Wy DSM - Cat3 - Carrying Charges	OTHER	(86)	-	-	-	-	-	-	-	(86)
1823940 Total					**2,719**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**2,719**
1823990	OTHR REG ASSET-N CST	138020	Reg Asset Current - DSM	OTHER	1,049	-	-	-	-	-	-	-	1,049
1823990	OTHR REG ASSET-N CST	138042	Reg Asset Current - Electric Transport	OTHER	1,379	-	-	-	-	-	-	-	1,379
1823990	OTHR REG ASSET-N CST	138045	Reg Asset Current - GHG Allowances	OTHER	8,513	-	-	-	-	-	-	-	8,513
1823990	OTHR REG ASSET-N CST	138050	Reg Asset Current - Def Net Power Costs	OTHER	746,409	-	-	-	-	-	-	-	746,409
1823990	OTHR REG ASSET-N CST	138055	Reg Asset Current - Def RECs in Rates	OTHER	250	-	-	-	-	-	-	-	250
1823990	OTHR REG ASSET-N CST	138060	Reg Asset Current - BPA Balancing Accts	OTHER	1,065	-	-	-	-	-	-	-	1,065
1823990	OTHR REG ASSET-N CST	138075	Reg Asset Current - Wildfire Mitigation	OTHER	22,147	-	-	-	-	-	-	-	22,147
1823990	OTHR REG ASSET-N CST	138090	Reg Asset Current - Solar Feed-In	OTHER	7,113	-	-	-	-	-	-	-	7,113
1823990	OTHR REG ASSET-N CST	138190	Reg Asset Current - Other	OTHER	50,605	-	-	-	-	-	-	-	50,605
1823990	OTHR REG ASSET-N CST	186100	Calif Alternative Rate for Energy (CARE)	OTHER	3,729	-	-	-	-	-	-	-	3,729
1823990	OTHR REG ASSET-N CST	186119	Reg Asset - DSM - CA - Balance Reclass	OTHER	1,008	-	-	-	-	-	-	-	1,008
1823990	OTHR REG ASSET-N CST	186129	Reg Asset - DSM - ID - Balance Reclass	OTHER	4,890	-	-	-	-	-	-	-	4,890
1823990	OTHR REG ASSET-N CST	186139	Reg Asset - DSM - OR - Balance Reclass	OTHER	1,567	-	-	-	-	-	-	-	1,567
1823990	OTHR REG ASSET-N CST	186157	RegA - DSM - WA - Reclass to Current	OTHER	(1,049)	-	-	-	-	-	-	-	(1,049)
1823990	OTHR REG ASSET-N CST	187042	Reg Asset - CA GHG Allowances	OTHER	(5,363)	-	-	-	-	-	-	-	(5,363)
1823990	OTHR REG ASSET-N CST	187048	RegA - CA GHG Allowances - Recl to Curr	OTHER	(8,513)	-	-	-	-	-	-	-	(8,513)
1823990	OTHR REG ASSET-N CST	187049	RegA - CA GHG Allowances - Balance Recl	OTHER	13,876	-	-	-	-	-	-	-	13,876

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-UPL + Wy-PPL	Utah	Id-PPL + Idaho	FERC	Other
1823990	OTHR REG ASSET-N CST	187230	RegA - Oregon OCAT Expense Deferral	OTHER	(133)	-	-	-	-	-	-	-	(133)
1823990	OTHR REG ASSET-N CST	187231	Reg Asset - Oregon Metro BIT	OTHER	0	-	-	-	-	-	-	-	0
1823990	OTHR REG ASSET-N CST	187239	RegA-Income Tax Related-Recl to Liab	OTHER	133	-	-	-	-	-	-	-	133
1823990	OTHR REG ASSET-N CST	187255	RegA - BPA Balancing Accts - Recl to Cur	OTHER	(1,065)	-	-	-	-	-	-	-	(1,065)
1823990	OTHR REG ASSET-N CST	187300	CA - Jan 2010 Storm Costs	OTHER	23,984	-	-	-	-	-	-	-	23,984
1823990	OTHR REG ASSET-N CST	187301	Reg Asset - CA - CEMA Costs Deferral	OTHER	(2,480)	-	-	-	-	-	-	-	(2,480)
1823990	OTHR REG ASSET-N CST	187302	RegA-OR Low Income Bill Discount	OTHER	9,436	-	-	-	-	-	-	-	9,436
1823990	OTHR REG ASSET-N CST	187303	RegA-OR Low Income Bill Disc Admin Cost	OTHER	701	-	-	-	-	-	-	-	701
1823990	OTHR REG ASSET-N CST	187304	RegA-CA Emerg Svc Prgms-Battery Storage	OTHER	(270)	-	-	-	-	-	-	-	(270)
1823990	OTHR REG ASSET-N CST	187308	RegA - WY Low-Carbon Energy Standards	OTHER	(4,094)	-	-	-	-	-	-	-	(4,094)
1823990	OTHR REG ASSET-N CST	187309	RegA-OR Utility Community Advisory Group	OTHER	(230)	-	-	-	-	-	-	-	(230)
1823990	OTHR REG ASSET-N CST	187320	Reg Asset - Deprec Increase - ID	IDU	1,743	-	-	-	-	-	1,743	-	-
1823990	OTHR REG ASSET-N CST	187321	Reg Asset - Deprec Increase - UT	UT	768	-	-	-	-	768	-	-	-
1823990	OTHR REG ASSET-N CST	187322	Reg Asset - Deprec Increase - WY	WYP	2,653	-	-	-	2,653	-	-	-	-
1823990	OTHR REG ASSET-N CST	187332	STEAM PLANT DEPR & DECOM REG ASSETS-UT	UT	213	-	-	-	-	213	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	CA	(52)	(52)	-	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	IDU	(197)	-	-	-	-	-	(197)	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	OR	(808)	-	(808)	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	SG	3,446	48	957	253	459	1,537	194	0	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	UT	(1,517)	-	-	-	-	(1,517)	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	WA	(278)	-	-	(278)	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	WYU	(504)	-	-	-	(504)	-	-	-	-
1823990	OTHR REG ASSET-N CST	187350	ID - Deferred Overburden Costs	OTHER	1,180	-	-	-	-	-	-	-	1,180
1823990	OTHR REG ASSET-N CST	187351	WY - Deferred Overburden Costs	WYP	2,822	-	-	-	2,822	-	-	-	-
1823990	OTHR REG ASSET-N CST	187354	RegA-OR 2020 GRC-Meters Replcd by AMI	OTHER	2,085	-	-	-	-	-	-	-	2,085
1823990	OTHR REG ASSET-N CST	187357	CA Mobile Home Park Conversion (MHPCBA)	OTHER	154	-	-	-	-	-	-	-	154
1823990	OTHR REG ASSET-N CST	187361	Reg A-OR-COVID-19 Bill Assistance Prog	OTHER	5,764	-	-	-	-	-	-	-	5,764
1823990	OTHR REG ASSET-N CST	187369	RegA -WA Equity Advisory Group (CETA)	OTHER	1,055	-	-	-	-	-	-	-	1,055
1823990	OTHR REG ASSET-N CST	187383	RegA - OR Solar Feed-In - Recl to Curr	OTHER	(6,966)	-	-	-	-	-	-	-	(6,966)
1823990	OTHR REG ASSET-N CST	187384	RegA - UT Solar Feed-In - Recl to Curr	OTHER	(147)	-	-	-	-	-	-	-	(147)
1823990	OTHR REG ASSET-N CST	187390	UT-Klamath Hydro Relicensing Costs	OTHER	(0)	-	-	-	-	-	-	-	(0)
1823990	OTHR REG ASSET-N CST	187396	Reg Asset-OR Solar Feed-In Tariff 2024	OTHER	2,053	-	-	-	-	-	-	-	2,053
1823990	OTHR REG ASSET-N CST	187397	Reg Asset-OR Solar Feed-In Tariff 2025	OTHER	2,425	-	-	-	-	-	-	-	2,425
1823990	OTHR REG ASSET-N CST	187415	Reg Asset-UT Subscriber Solar Program	OTHER	1,720	-	-	-	-	-	-	-	1,720
1823990	OTHR REG ASSET-N CST	187420	RegA - OR Community Solar	OTHER	3,700	-	-	-	-	-	-	-	3,700
1823990	OTHR REG ASSET-N CST	187488	RegA-WA Decoupling Mech - Recl to Curr	OTHER	(5,407)	-	-	-	-	-	-	-	(5,407)
1823990	OTHR REG ASSET-N CST	187489	Reg A-WA Decoupling Mechanism-Reclass	OTHER	9,637	-	-	-	-	-	-	-	9,637
1823990	OTHR REG ASSET-N CST	187495	RegA - Other - Recl to Curr	OTHER	(26,145)	-	-	-	-	-	-	-	(26,145)
1823990	OTHR REG ASSET-N CST	187616	ID 2025 GRC Rev Req Deferral	IDU	1,700	-	-	-	-	-	1,700	-	-
1823990	OTHR REG ASSET-N CST	187651	RegA-OR TB Flats	OTHER	1,727	-	-	-	-	-	-	-	1,727
1823990	OTHR REG ASSET-N CST	187652	RegA-OR Cedar Springs II	OTHER	84	-	-	-	-	-	-	-	84
1823990	OTHR REG ASSET-N CST	187653	CA 2023 GRC Memo Account	CA	9,445	9,445	-	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187656	RegA - Injuries & Damages-Recl to Liab	OTHER	3,443	-	-	-	-	-	-	-	3,443
1823990	OTHR REG ASSET-N CST	187657	RegA - Insurance Reserves-Recl to Liab	OTHER	1,747	-	-	-	-	-	-	-	1,747
1823990	OTHR REG ASSET-N CST	187659	RegA-CA Insurance Reserves-Recl to Liab	OTHER	4,551	-	-	-	-	-	-	-	4,551
1823990	OTHR REG ASSET-N CST	187660	RegA-OR Transp Electrification Pilot	OTHER	955	-	-	-	-	-	-	-	955
1823990	OTHR REG ASSET-N CST	187661	RegA-UT Elec Vehicle Charging Infrast	OTHER	423	-	-	-	-	-	-	-	423
1823990	OTHR REG ASSET-N CST	187662	RegA-CA Transp Electrification Pilot	OTHER	(262)	-	-	-	-	-	-	-	(262)
1823990	OTHR REG ASSET-N CST	187664	RegA-WA Transp Electrification Pilot	OTHER	344	-	-	-	-	-	-	-	344
1823990	OTHR REG ASSET-N CST	187665	RegA-OR Residential Charging Pilot	OTHER	(6,000)	-	-	-	-	-	-	-	(6,000)
1823990	OTHR REG ASSET-N CST	187840	Reg Asset - UT RBA CY2024	OTHER	(1,533)	-	-	-	-	-	-	-	(1,533)
1823990	OTHR REG ASSET-N CST	187841	Reg Asset - UT RBA CY2025	OTHER	(4,588)	-	-	-	-	-	-	-	(4,588)
1823990	OTHR REG ASSET-N CST	187861	Reg Asset - WY RRA CY2023	OTHER	(508)	-	-	-	-	-	-	-	(508)
1823990	OTHR REG ASSET-N CST	187870	Reg Asset - WY RRA CY2024	OTHER	257	-	-	-	-	-	-	-	257
1823990	OTHR REG ASSET-N CST	187871	Reg Asset - WY RRA CY2025	OTHER	(721)	-	-	-	-	-	-	-	(721)
1823990	OTHR REG ASSET-N CST	187886	Reg Asset-OR RPS Compliance Purchases	OTHER	(1,143)	-	-	-	-	-	-	-	(1,143)
1823990	OTHR REG ASSET-N CST	187895	RegA - OR RECs in Rates - Balance Recl	OTHER	1,143	-	-	-	-	-	-	-	1,143
1823990	OTHR REG ASSET-N CST	187897	RegA - UT RECs in Rates - Recl to Liab	OTHER	6,121	-	-	-	-	-	-	-	6,121
1823990	OTHR REG ASSET-N CST	187898	RegA - Def RECs in Rates - Recl to Curr	OTHER	(250)	-	-	-	-	-	-	-	(250)
1823990	OTHR REG ASSET-N CST	187899	RegA - WY RECs in Rates - Recl to Liab	OTHER	1,228	-	-	-	-	-	-	-	1,228
1823990	OTHR REG ASSET-N CST	187911	REG ASSET - LAKE SIDE LIQ. DAMAGES - WY	WYP	608	-	-	-	608	-	-	-	-
1823990	OTHR REG ASSET-N CST	187913	Reg Asset - Goodnoe Hills Liq. Damages -	WYP	181	-	-	-	181	-	-	-	-
1823990	OTHR REG ASSET-N CST	187914	"Reg Asset-UT-Liq. Damages JB4, N1&2"	UT	297	-	-	-	-	297	-	-	-

PACIFICORP

Regulatory Assests (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-UPL + Wy-PPL	Utah	Id-PPL + Idaho	FERC	Other
1823990	OTHR REG ASSET-N CST	187915	Reg Asset-WY-Liq. Damages N2	WYP	49	-	-	-	49	-	-	-	-
1823990	OTHR REG ASSET-N CST	187916	Reg Asset-WY Wind Test Energy Deferral	WYU	194	-	-	-	194	-	-	-	-
1823990	OTHR REG ASSET-N CST	187952	DEFERRED INTERVENER	OTHER	0	-	-	-	-	-	-	-	0
1823990	OTHR REG ASSET-N CST	187956	CA DEFERRED INTERVENOR FUNDING	OTHER	462	-	-	-	-	-	-	-	462
1823990	OTHR REG ASSET-N CST	187957	DEFERRED OR INDEPENDENT EVALUATOR FEES	OTHER	173	-	-	-	-	-	-	-	173
1823990	OTHR REG ASSET-N CST	187958	ID Deferred Intervenor Funding	IDU	35	-	-	-	-	-	35	-	-
1823990	OTHR REG ASSET-N CST	187959	WA Deferred Intervenor Funding	OTHER	216	-	-	-	-	-	-	-	216
1823990	OTHR REG ASSET-N CST	187968	Reg A - Insurance Reserves - Reclass	OTHER	48,748	-	-	-	-	-	-	-	48,748
1823990	OTHR REG ASSET-N CST	187975	Reg Asset - CA ECAC	OTHER	(2,205)	-	-	-	-	-	-	-	(2,205)
1823990	OTHR REG ASSET-N CST	187989	Reg Asset - OR PCAM FY2021	OTHER	25,716	-	-	-	-	-	-	-	25,716
1823990	OTHR REG ASSET-N CST	189001	RegA-CA Fire Risk Mitigation (FRMMA)	OTHER	612	-	-	-	-	-	-	-	612
1823990	OTHR REG ASSET-N CST	189002	RegA-CA Wildfire Mitigation Plan(WMPMA)	OTHER	75,992	-	-	-	-	-	-	-	75,992
1823990	OTHR REG ASSET-N CST	189003	Contra RegA-CA Fire/Wildlife Mitigation	OTHER	(14,329)	-	-	-	-	-	-	-	(14,329)
1823990	OTHR REG ASSET-N CST	189004	RegA-CA Fire Hazard Prevention (FHPMA)	OTHER	3,229	-	-	-	-	-	-	-	3,229
1823990	OTHR REG ASSET-N CST	189005	RegA-CA Wildfire/Natl Disaster (WNDRR)	OTHER	97	-	-	-	-	-	-	-	97
1823990	OTHR REG ASSET-N CST	189006	RegA-CA Emerg Cust Protections (ECPMA)	OTHER	7	-	-	-	-	-	-	-	7
1823990	OTHR REG ASSET-N CST	189011	Reg Asset-UT Wildland Fire Protection	OTHER	26,304	-	-	-	-	-	-	-	26,304
1823990	OTHR REG ASSET-N CST	189012	RegA-UT WBA 2024 GRC Deferral	OTHER	5,615	-	-	-	-	-	-	-	5,615
1823990	OTHR REG ASSET-N CST	189015	Contra RegA-UT Wildland Fire Prot	OTHER	(26,304)	-	-	-	-	-	-	-	(26,304)
1823990	OTHR REG ASSET-N CST	189016	Reg Asset-OR Wildfire Mitigation Acct	OTHER	(11,750)	-	-	-	-	-	-	-	(11,750)
1823990	OTHR REG ASSET-N CST	189020	Contra RegA-OR Wildfire Mitigation	OTHER	(428)	-	-	-	-	-	-	-	(428)
1823990	OTHR REG ASSET-N CST	189021	RegA-OR Wildfire WMVM 2023	OTHER	10,284	-	-	-	-	-	-	-	10,284
1823990	OTHR REG ASSET-N CST	189022	RegA-OR Wildfire WMVM 2024	OTHER	20,726	-	-	-	-	-	-	-	20,726
1823990	OTHR REG ASSET-N CST	189027	RegA-OR Wildfire Restoration Costs	OTHER	10,854	-	-	-	-	-	-	-	10,854
1823990	OTHR REG ASSET-N CST	189029	RegA-Wildfire Mitigation - Recl to Curr	OTHER	(22,147)	-	-	-	-	-	-	-	(22,147)
1823990	OTHR REG ASSET-N CST	189030	Klamath Unrecovered Plant and Transfer	SG	7,484	104	2,077	549	996	3,337	421	0	-
1823990	OTHR REG ASSET-N CST	189031	RegA - NTO Transfer Deferral	OTHER	4,212	-	-	-	-	-	-	-	4,212
1823990	OTHR REG ASSET-N CST	189032	Klamath Unrecovered Plant - OR	OTHER	803	-	-	-	-	-	-	-	803
1823990	OTHR REG ASSET-N CST	189033	Contra Klamath Unrecovered Plant - OR	OTHER	(792)	-	-	-	-	-	-	-	(792)
1823990	OTHR REG ASSET-N CST	189131	RegA-ID Deferred Insurance Premiums	OTHER	3,606	-	-	-	-	-	-	-	3,606
1823990	OTHR REG ASSET-N CST	189132	RegA-OR Deferred Insurance Premiums	OTHER	33,831	-	-	-	-	-	-	-	33,831
1823990	OTHR REG ASSET-N CST	189133	RegA-WY Deferred Insurance Premiums	OTHER	11,895	-	-	-	-	-	-	-	11,895
1823990	OTHR REG ASSET-N CST	189137	RegA-Def Insurance Premium-Recl to Curr	OTHER	(19,053)	-	-	-	-	-	-	-	(19,053)
1823990	OTHR REG ASSET-N CST	189508	Reg Asset - CA ECAC CY2023	OTHER	17,458	-	-	-	-	-	-	-	17,458
1823990	OTHR REG ASSET-N CST	189509	Contra Reg Asset - CA ECAC CY2023	OTHER	(873)	-	-	-	-	-	-	-	(873)
1823990	OTHR REG ASSET-N CST	189510	Reg Asset - CA ECAC CY2024	OTHER	13,063	-	-	-	-	-	-	-	13,063
1823990	OTHR REG ASSET-N CST	189511	Contra Reg Asset - CA ECAC CY2024	OTHER	(662)	-	-	-	-	-	-	-	(662)
1823990	OTHR REG ASSET-N CST	189512	Reg Asset - CA ECAC CY2025	OTHER	(1,905)	-	-	-	-	-	-	-	(1,905)
1823990	OTHR REG ASSET-N CST	189513	Contra Reg Asset - CA ECAC CY2025	OTHER	(95)	-	-	-	-	-	-	-	(95)
1823990	OTHR REG ASSET-N CST	189528	RegA - CA Def Exc NPC - Recl to Curr	OTHER	(16,488)	-	-	-	-	-	-	-	(16,488)
1823990	OTHR REG ASSET-N CST	189539	Reg Asset-ID ECAM CY 2024	OTHER	67,066	-	-	-	-	-	-	-	67,066
1823990	OTHR REG ASSET-N CST	189550	Reg Asset - ID ECAM CY 2025	OTHER	(1,043)	-	-	-	-	-	-	-	(1,043)
1823990	OTHR REG ASSET-N CST	189551	Contra Reg Asset - ID ECAM CY2025	OTHER	(55)	-	-	-	-	-	-	-	(55)
1823990	OTHR REG ASSET-N CST	189568	RegA - ID Def Exc NPC - Recl to Curr	OTHER	(32,867)	-	-	-	-	-	-	-	(32,867)
1823990	OTHR REG ASSET-N CST	189586	Reg Asset - OR PCAM FY2022	OTHER	54,911	-	-	-	-	-	-	-	54,911
1823990	OTHR REG ASSET-N CST	189588	Reg Asset - OR PCAM CY2023	OTHER	100,771	-	-	-	-	-	-	-	100,771
1823990	OTHR REG ASSET-N CST	189590	Reg Asset - OR PCAM CY2024	OTHER	15,439	-	-	-	-	-	-	-	15,439
1823990	OTHR REG ASSET-N CST	189591	Contra Reg Asset - OR PCAM CY2024	OTHER	(3,932)	-	-	-	-	-	-	-	(3,932)
1823990	OTHR REG ASSET-N CST	189598	RegA - OR Def Exc NPC - Recl to Curr	OTHER	(128,483)	-	-	-	-	-	-	-	(128,483)
1823990	OTHR REG ASSET-N CST	189612	Reg Asset - UT EBA CY2022	OTHER	246	-	-	-	-	-	-	-	246
1823990	OTHR REG ASSET-N CST	189613	Reg Asset - UT EBA CY2023	OTHER	(36,867)	-	-	-	-	-	-	-	(36,867)
1823990	OTHR REG ASSET-N CST	189614	Reg Asset - UT EBA CY2024	OTHER	484,929	-	-	-	-	-	-	-	484,929
1823990	OTHR REG ASSET-N CST	189615	Reg Asset - UT EBA CY2025	OTHER	100,272	-	-	-	-	-	-	-	100,272
1823990	OTHR REG ASSET-N CST	189624	Contra Reg Asset - UT EBA CY2024	OTHER	(12,125)	-	-	-	-	-	-	-	(12,125)
1823990	OTHR REG ASSET-N CST	189625	Contra Reg Asset - UT EBA CY2025	OTHER	(4,954)	-	-	-	-	-	-	-	(4,954)
1823990	OTHR REG ASSET-N CST	189638	RegA - UT Def Exc NPC - Recl to Curr	OTHER	(363,933)	-	-	-	-	-	-	-	(363,933)
1823990	OTHR REG ASSET-N CST	189643	Reg Asset - WA PCAM PTC CY2022	OTHER	914	-	-	-	-	-	-	-	914
1823990	OTHR REG ASSET-N CST	189644	Reg Asset - WA PCAM PTC CY2023	OTHER	792	-	-	-	-	-	-	-	792
1823990	OTHR REG ASSET-N CST	189645	Reg Asset - WA PCAM CY2023	OTHER	55,617	-	-	-	-	-	-	-	55,617
1823990	OTHR REG ASSET-N CST	189647	Reg Asset - WA PCAM CY2024	OTHER	51,559	-	-	-	-	-	-	-	51,559
1823990	OTHR REG ASSET-N CST	189648	RegA - WA Def Exc NPC - Recl to Curr	OTHER	(118,791)	-	-	-	-	-	-	-	(118,791)
1823990	OTHR REG ASSET-N CST	189649	RegA - WA Def Exc NPC - Recl to Liab	OTHER	57,006	-	-	-	-	-	-	-	57,006
1823990	OTHR REG ASSET-N CST	189653	Reg Asset - WY ECAM CY2023	OTHER	16,452	-	-	-	-	-	-	-	16,452

PACIFICORP

Regulatory Assests (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wy-UPL + Wy-PPL	Utah	Id-PPL + Idaho	FERC	Other
1823990	OTHR REG ASSET-N CST	189654	Reg Asset - WY ECAM CY2024	OTHER	73,046	-	-	-	-	-	-	-	73,046
1823990	OTHR REG ASSET-N CST	189655	Reg Asset - WY ECAM CY2025	OTHER	8,800	-	-	-	-	-	-	-	8,800
1823990	OTHR REG ASSET-N CST	189664	Contra Reg Asset - WY ECAM CY2024	OTHER	(3,652)	-	-	-	-	-	-	-	(3,652)
1823990	OTHR REG ASSET-N CST	189665	Contra Reg Asset - WY ECAM CY2025	OTHER	(440)	-	-	-	-	-	-	-	(440)
1823990	OTHR REG ASSET-N CST	189688	RegA - WY Def Exc NPC - Recl to Curr	OTHER	(85,846)	-	-	-	-	-	-	-	(85,846)
1823990	OTHR REG ASSET-N CST	189690	Contra Reg Asset - WA PCAM CY2024	OTHER	(2,577)	-	-	-	-	-	-	-	(2,577)
1823990	OTHR REG ASSET-N CST	189691	Reg Asset - WA PTC CY2024	OTHER	(953)	-	-	-	-	-	-	-	(953)
1823990	OTHR REG ASSET-N CST	189694	Reg Asset - WA PTC CY2025	OTHER	(2,705)	-	-	-	-	-	-	-	(2,705)
1823990 Total					**1,386,539**	**9,545**	**2,226**	**524**	**7,457**	**4,635**	**3,896**	**0**	**1,358,256**
1823999	REGULATORY ASST-OTH	186011	DSM Reg Asset - Accruals - CA	OTHER	79	-	-	-	-	-	-	-	79
1823999	REGULATORY ASST-OTH	186015	DSM Reg Asset - Balancing Acct - CA	OTHER	(1,087)	-	-	-	-	-	-	-	(1,087)
1823999	REGULATORY ASST-OTH	186021	DSM Reg Asset - Accruals - ID	OTHER	258	-	-	-	-	-	-	-	258
1823999	REGULATORY ASST-OTH	186025	DSM Reg Asset - Balancing Acct - ID	OTHER	(5,148)	-	-	-	-	-	-	-	(5,148)
1823999	REGULATORY ASST-OTH	186035	DSM Reg Asset - Balancing Acct - OR	OTHER	(1,567)	-	-	-	-	-	-	-	(1,567)
1823999	REGULATORY ASST-OTH	186041	DSM Reg Asset - Accruals - UT	OTHER	3,109	-	-	-	-	-	-	-	3,109
1823999	REGULATORY ASST-OTH	186045	DSM Reg Asset - Balancing Acct - UT	OTHER	(4,901)	-	-	-	-	-	-	-	(4,901)
1823999	REGULATORY ASST-OTH	186051	DSM Reg Asset - Accruals - WA	OTHER	1,219	-	-	-	-	-	-	-	1,219
1823999	REGULATORY ASST-OTH	186055	DSM Reg Asset - Balancing Acct - WA	OTHER	(170)	-	-	-	-	-	-	-	(170)
1823999	REGULATORY ASST-OTH	186061	DSM Reg Asset - Accruals - WY	OTHER	227	-	-	-	-	-	-	-	227
1823999	REGULATORY ASST-OTH	186065	DSM Reg Asset - Balancing Acct - WY	OTHER	(603)	-	-	-	-	-	-	-	(603)
1823999	REGULATORY ASST-OTH	186071	DSM Reg Asset - Accruals - WY Cat 1	OTHER	80	-	-	-	-	-	-	-	80
1823999	REGULATORY ASST-OTH	186075	DSM Reg Asset-Balancing Acct-WY Cat 1	OTHER	163	-	-	-	-	-	-	-	163
1823999	REGULATORY ASST-OTH	186081	DSM Reg Asset - Accruals - WY Cat 2	OTHER	74	-	-	-	-	-	-	-	74
1823999	REGULATORY ASST-OTH	186085	DSM Reg Asset-Balancing Acct-WY Cat 2	OTHER	(1,014)	-	-	-	-	-	-	-	(1,014)
1823999	REGULATORY ASST-OTH	186086	DSM Dem Resp Reg Asset - WY	OTHER	(524)	-	-	-	-	-	-	-	(524)
1823999 Total					**(9,805)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(9,805)**
Grand Total					**2,168,766**	**22,220**	**132,727**	**24,292**	**84,486**	**185,546**	**25,001**	**17**	**1,694,477**

B17.DEPRECIATION RESERVE

PACIFICORP

Depreciation Reserve (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3102000	LAND RIGHTS	SG	(497)	(7)	(138)	(36)	(66)	(222)	(28)	(0)	-
1080000	AC PR DPR EL PL SR	3103000	WATER RIGHTS	SG	(14,473)	(201)	(4,017)	(1,062)	(1,926)	(6,453)	(814)	(1)	-
1080000	AC PR DPR EL PL SR	3110000	STRUCTURES AND IMPROVEMENTS	SG	(720,540)	(9,988)	(199,990)	(52,856)	(95,865)	(321,265)	(40,546)	(29)	-
1080000	AC PR DPR EL PL SR	3120000	BOILER PLANT EQUIPMENT	SG	(2,757,750)	(38,229)	(765,429)	(202,298)	(366,908)	(1,229,590)	(155,184)	(112)	-
1080000	AC PR DPR EL PL SR	3140000	TURBOGENERATOR UNITS	SG	(586,928)	(8,136)	(162,905)	(43,055)	(78,088)	(261,692)	(33,027)	(24)	-
1080000	AC PR DPR EL PL SR	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	(304,350)	(4,219)	(84,474)	(22,326)	(40,493)	(135,700)	(17,126)	(12)	-
1080000	AC PR DPR EL PL SR	3151000	COMPUTER HARDWARE - STEAM	SG	(165)	(2)	(46)	(12)	(22)	(73)	(9)	(0)	-
1080000	AC PR DPR EL PL SR	3152000	COMPUTER SOFTWARE (MISC) - STEAM	SG	(32)	(0)	(9)	(2)	(4)	(14)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3153000	COMMUNICATION EQUIPMENT - STEAM	SG	(11,359)	(157)	(3,153)	(833)	(1,511)	(5,064)	(639)	(0)	-
1080000	AC PR DPR EL PL SR	3153005	COMM EQUIP - MOBILE RADIOS - STEAM	SG	(68)	(1)	(19)	(5)	(9)	(31)	(4)	(0)	-
1080000	AC PR DPR EL PL SR	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	(38)	(1)	(11)	(3)	(5)	(17)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	(19,201)	(266)	(5,329)	(1,409)	(2,555)	(8,561)	(1,080)	(1)	-
1080000	AC PR DPR EL PL SR	3302000	LAND RIGHTS	SG-P	(3,688)	(51)	(1,024)	(271)	(491)	(1,644)	(208)	(0)	-
1080000	AC PR DPR EL PL SR	3302000	LAND RIGHTS	SG-U	(281)	(4)	(78)	(21)	(37)	(125)	(16)	(0)	-
1080000	AC PR DPR EL PL SR	3303000	WATER RIGHTS	SG-P	(1)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3303000	WATER RIGHTS	SG-U	(118)	(2)	(33)	(9)	(16)	(52)	(7)	(0)	-
1080000	AC PR DPR EL PL SR	3304000	FLOOD RIGHTS	SG-P	(28)	(0)	(8)	(2)	(4)	(12)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3304000	FLOOD RIGHTS	SG-U	(84)	(1)	(23)	(6)	(11)	(38)	(5)	(0)	-
1080000	AC PR DPR EL PL SR	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	(172)	(2)	(48)	(13)	(23)	(77)	(10)	(0)	-
1080000	AC PR DPR EL PL SR	3310000	STRUCTURES AND IMPROVE	SG-P	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3310000	STRUCTURES AND IMPROVE	SG-U	(6,462)	(90)	(1,793)	(474)	(860)	(2,881)	(364)	(0)	-
1080000	AC PR DPR EL PL SR	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	(29,965)	(415)	(8,317)	(2,198)	(3,987)	(13,360)	(1,686)	(1)	-
1080000	AC PR DPR EL PL SR	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	(3,911)	(54)	(1,085)	(287)	(520)	(1,744)	(220)	(0)	-
1080000	AC PR DPR EL PL SR	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	(43,154)	(598)	(11,978)	(3,166)	(5,741)	(19,241)	(2,428)	(2)	-
1080000	AC PR DPR EL PL SR	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	(326)	(5)	(90)	(24)	(43)	(145)	(18)	(0)	-
1080000	AC PR DPR EL PL SR	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	(8,463)	(117)	(2,349)	(621)	(1,126)	(3,773)	(476)	(0)	-
1080000	AC PR DPR EL PL SR	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	(1,234)	(17)	(342)	(90)	(164)	(550)	(69)	(0)	-
1080000	AC PR DPR EL PL SR	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	(2,224)	(31)	(617)	(163)	(296)	(991)	(125)	(0)	-
1080000	AC PR DPR EL PL SR	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	(21,807)	(302)	(6,053)	(1,600)	(2,901)	(9,723)	(1,227)	(1)	-
1080000	AC PR DPR EL PL SR	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	(191,170)	(2,650)	(53,060)	(14,023)	(25,434)	(85,236)	(10,757)	(8)	-
1080000	AC PR DPR EL PL SR	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	(50,140)	(695)	(13,917)	(3,678)	(6,671)	(22,356)	(2,821)	(2)	-
1080000	AC PR DPR EL PL SR	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	(6,860)	(95)	(1,904)	(503)	(913)	(3,058)	(386)	(0)	-
1080000	AC PR DPR EL PL SR	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	(344)	(5)	(95)	(25)	(46)	(153)	(19)	(0)	-
1080000	AC PR DPR EL PL SR	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	(90)	(1)	(25)	(7)	(12)	(40)	(5)	(0)	-
1080000	AC PR DPR EL PL SR	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	(49)	(1)	(14)	(4)	(6)	(22)	(3)	(0)	-
1080000	AC PR DPR EL PL SR	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	(42,046)	(583)	(11,670)	(3,084)	(5,594)	(18,747)	(2,366)	(2)	-
1080000	AC PR DPR EL PL SR	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	(29,330)	(407)	(8,141)	(2,151)	(3,902)	(13,077)	(1,650)	(1)	-
1080000	AC PR DPR EL PL SR	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	(25,407)	(352)	(7,052)	(1,864)	(3,380)	(11,328)	(1,430)	(1)	-
1080000	AC PR DPR EL PL SR	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	(9,393)	(130)	(2,607)	(689)	(1,250)	(4,188)	(529)	(0)	-
1080000	AC PR DPR EL PL SR	3341000	COMPUTER HARDWARE - HYDRO	SG	(108)	(1)	(30)	(8)	(14)	(48)	(6)	(0)	-
1080000	AC PR DPR EL PL SR	3342000	COMPUTER SOFTWARE (MISC) - HYDRO	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3343000	COMMUNICATION EQUIPMENT - HYDRO	SG	(7,053)	(98)	(1,958)	(517)	(938)	(3,145)	(397)	(0)	-
1080000	AC PR DPR EL PL SR	3343005	COMM EQUIP - MOBILE RADIOS - HYDRO	SG	(38)	(1)	(10)	(3)	(5)	(17)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	(1,359)	(19)	(377)	(100)	(181)	(606)	(76)	(0)	-
1080000	AC PR DPR EL PL SR	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	(28)	(0)	(8)	(2)	(4)	(13)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3350000	MISC POWER PLANT EQUIP	SG-U	(147)	(2)	(41)	(11)	(20)	(66)	(8)	(0)	-
1080000	AC PR DPR EL PL SR	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	(1,392)	(19)	(386)	(102)	(185)	(621)	(78)	(0)	-
1080000	AC PR DPR EL PL SR	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	(9,657)	(134)	(2,680)	(708)	(1,285)	(4,306)	(543)	(0)	-
1080000	AC PR DPR EL PL SR	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	(1,898)	(26)	(527)	(139)	(253)	(846)	(107)	(0)	-
1080000	AC PR DPR EL PL SR	3380002	STRUCTURES AND IMPROVEMENTS - SOLAR	OR	(1)	-	(1)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3380002	STRUCTURES AND IMPROVEMENTS - SOLAR	UT	(14)	-	-	-	-	(14)	-	-	-
1080000	AC PR DPR EL PL SR	3380004	SOLAR PANELS	SG	(67)	(1)	(19)	(5)	(9)	(30)	(4)	(0)	-
1080000	AC PR DPR EL PL SR	3380004	SOLAR PANELS	UT	(33)	-	-	-	-	(33)	-	-	-
1080000	AC PR DPR EL PL SR	3380005	COLLECTOR SYSTEM - SOLAR	UT	(26)	-	-	-	-	(26)	-	-	-
1080000	AC PR DPR EL PL SR	3380007	INVERTERS - SOLAR	UT	(7)	-	-	-	-	(7)	-	-	-
1080000	AC PR DPR EL PL SR	3380008	ACCESSORY ELECTRIC EQUIPMENT - SOLAR	UT	(5)	-	-	-	-	(5)	-	-	-

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Depreciation Reserve (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3380011	COMMUNICATION EQUIPMENT - SOLAR	OR	(10)	-	(10)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3382000	LAND RIGHTS - WIND PRODUCTION	SG	(369)	(5)	(102)	(27)	(49)	(165)	(21)	(0)	-
1080000	AC PR DPR EL PL SR	3382100	STRUCTURES AND IMPROVEMENTS - WIND	SG	(8,693)	(121)	(2,413)	(638)	(1,157)	(3,876)	(489)	(0)	-
1080000	AC PR DPR EL PL SR	3382300	WIND TURBINES	SG	(114,282)	(1,584)	(31,720)	(8,383)	(15,205)	(50,955)	(6,431)	(5)	-
1080000	AC PR DPR EL PL SR	3382301	WIND TURBINES - GENERATORS	SG	(9,635)	(134)	(2,674)	(707)	(1,282)	(4,296)	(542)	(0)	-
1080000	AC PR DPR EL PL SR	3382400	WIND TOWERS AND FIXTURES	SG	(8,979)	(124)	(2,492)	(659)	(1,195)	(4,003)	(505)	(0)	-
1080000	AC PR DPR EL PL SR	3382600	COLLECTOR SYSTEM - WIND	SG	(14,893)	(206)	(4,134)	(1,092)	(1,981)	(6,640)	(838)	(1)	-
1080000	AC PR DPR EL PL SR	3382700	GSU AND ASSOC EQUIP - WIND	SG	(734)	(10)	(204)	(54)	(98)	(327)	(41)	(0)	-
1080000	AC PR DPR EL PL SR	3382800	INVERTERS - WIND	SG	(94)	(1)	(26)	(7)	(12)	(42)	(5)	(0)	-
1080000	AC PR DPR EL PL SR	3382900	ACCESSORY ELECTRIC EQUIPMENT - WIND	SG	(66)	(1)	(18)	(5)	(9)	(29)	(4)	(0)	-
1080000	AC PR DPR EL PL SR	3383000	COMPUTER HARDWARE - WIND	SG	(111)	(2)	(31)	(8)	(15)	(49)	(6)	(0)	-
1080000	AC PR DPR EL PL SR	3383100	COMPUTER SOFTWARE (MISC) - WIND	SG	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3383200	COMMUNICATION EQUIPMENT - WIND	SG	(1,022)	(14)	(284)	(75)	(136)	(456)	(58)	(0)	-
1080000	AC PR DPR EL PL SR	3383205	COMM EQUIP - MOBILE RADIOS - WIND	SG	(27)	(0)	(7)	(2)	(4)	(12)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3383300	MISC POWER PLANT EQUIP - WIND	SG	(1,452)	(20)	(403)	(107)	(193)	(648)	(82)	(0)	-
1080000	AC PR DPR EL PL SR	3390001	LAND RIGHTS - OTHER REN	SG	(30,798)	(427)	(8,548)	(2,259)	(4,098)	(13,732)	(1,733)	(1)	-
1080000	AC PR DPR EL PL SR	3390002	STRUCTURES AND IMPROVEMENTS - OTHER REN	SG	(5,390)	(75)	(1,496)	(395)	(717)	(2,403)	(303)	(0)	-
1080000	AC PR DPR EL PL SR	3390003	FUEL HOLDERS - OTHER REN	SG	(35,717)	(495)	(9,913)	(2,620)	(4,752)	(15,925)	(2,010)	(1)	-
1080000	AC PR DPR EL PL SR	3390004	BOILER PLANT EQUIPMENT - OTHER REN	SG	(2,069)	(29)	(574)	(152)	(275)	(922)	(116)	(0)	-
1080000	AC PR DPR EL PL SR	3390006	GENERATORS - OTHER REN	SG	(20,997)	(291)	(5,828)	(1,540)	(2,794)	(9,362)	(1,182)	(1)	-
1080000	AC PR DPR EL PL SR	3390008	ACCESSORY ELECTRIC EQUIPMENT - OTHER REN	SG	(5,382)	(75)	(1,494)	(395)	(716)	(2,400)	(303)	(0)	-
1080000	AC PR DPR EL PL SR	3390009	COMPUTER HARDWARE - OTHER REN	SG	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3390011	COMMUNICATION EQUIPMENT - OTHER REN	SG	(458)	(6)	(127)	(34)	(61)	(204)	(26)	(0)	-
1080000	AC PR DPR EL PL SR	3390012	MISC POWER PLANT EQUIP - OTHER REN	SG	(874)	(12)	(243)	(64)	(116)	(390)	(49)	(0)	-
1080000	AC PR DPR EL PL SR	3390015	COMM EQUIP - MOBILE RADIOS - OTHER REN	SG	(11)	(0)	(3)	(1)	(1)	(5)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3410000	STRUCTURES & IMPROVEMENTS	SG	(55,739)	(773)	(15,471)	(4,089)	(7,416)	(24,852)	(3,137)	(2)	-
1080000	AC PR DPR EL PL SR	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	(5,906)	(82)	(1,639)	(433)	(786)	(2,633)	(332)	(0)	-
1080000	AC PR DPR EL PL SR	3430000	PRIME MOVERS	SG	(463,221)	(6,421)	(128,570)	(33,980)	(61,630)	(206,535)	(26,066)	(19)	-
1080000	AC PR DPR EL PL SR	3440000	GENERATORS	SG	(142,168)	(1,971)	(39,460)	(10,429)	(18,915)	(63,388)	(8,000)	(6)	-
1080000	AC PR DPR EL PL SR	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	(63,305)	(878)	(17,571)	(4,644)	(8,423)	(28,226)	(3,562)	(3)	-
1080000	AC PR DPR EL PL SR	3451000	COMPUTER HARDWARE - OTHER PROD	SG	(151)	(2)	(42)	(11)	(20)	(67)	(9)	(0)	-
1080000	AC PR DPR EL PL SR	3452000	COMPUTER SOFTWARE (MISC) - OTHER PROD	SG	(12)	(0)	(3)	(1)	(2)	(5)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3453000	COMMUNICATION EQUIPMENT - OTHER PROD	SG	(1,347)	(19)	(374)	(99)	(179)	(601)	(76)	(0)	-
1080000	AC PR DPR EL PL SR	3453005	COMM EQUIP - MOBILE RADIOS - OTHER PROD	SG	(45)	(1)	(13)	(3)	(6)	(20)	(3)	(0)	-
1080000	AC PR DPR EL PL SR	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	(3,840)	(53)	(1,066)	(282)	(511)	(1,712)	(216)	(0)	-
1080000	AC PR DPR EL PL SR	3502000	LAND RIGHTS	SG	(58,761)	(815)	(16,310)	(4,311)	(7,818)	(26,200)	(3,307)	(2)	-
1080000	AC PR DPR EL PL SR	3511000	COMPUTER HARDWARE - TRANS	SG	(64)	(1)	(18)	(5)	(8)	(28)	(4)	(0)	-
1080000	AC PR DPR EL PL SR	3512000	COMPUTER SOFTWARE (MISC) - TRANS	SG	(8)	(0)	(2)	(1)	(1)	(4)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3512001	MONARCH EMS/SCADA	SG	(31,628)	(438)	(8,778)	(2,320)	(4,208)	(14,102)	(1,780)	(1)	-
1080000	AC PR DPR EL PL SR	3512002	OMS - OPERATIONS MAPPING SYSTEM	SG	(10,386)	(144)	(2,883)	(762)	(1,382)	(4,631)	(584)	(0)	-
1080000	AC PR DPR EL PL SR	3512003	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	(10,133)	(140)	(2,813)	(743)	(1,348)	(4,518)	(570)	(0)	-
1080000	AC PR DPR EL PL SR	3513000	COMMUNICATION EQUIPMENT - TRANS	SG	(102,083)	(1,415)	(28,334)	(7,488)	(13,582)	(45,516)	(5,744)	(4)	-
1080000	AC PR DPR EL PL SR	3513005	COMM EQUIP - MOBILE RADIOS - TRANS	SG	(17)	(0)	(5)	(1)	(2)	(8)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3520000	STRUCTURES & IMPROVEMENTS	SG	(77,998)	(1,081)	(21,649)	(5,722)	(10,377)	(34,777)	(4,389)	(3)	-
1080000	AC PR DPR EL PL SR	3530000	STATION EQUIPMENT	SG	(648,688)	(8,992)	(180,047)	(47,585)	(86,305)	(289,229)	(36,503)	(26)	-
1080000	AC PR DPR EL PL SR	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	(51,336)	(712)	(14,249)	(3,766)	(6,830)	(22,889)	(2,889)	(2)	-
1080000	AC PR DPR EL PL SR	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	(7,483)	(104)	(2,077)	(549)	(996)	(3,336)	(421)	(0)	-
1080000	AC PR DPR EL PL SR	3540000	TOWERS AND FIXTURES	SG	(473,863)	(6,569)	(131,523)	(34,761)	(63,046)	(211,280)	(26,665)	(19)	-
1080000	AC PR DPR EL PL SR	3550000	POLES AND FIXTURES	SG	(514,017)	(7,125)	(142,668)	(37,706)	(68,388)	(229,183)	(28,925)	(21)	-
1080000	AC PR DPR EL PL SR	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	(625,682)	(8,673)	(173,662)	(45,898)	(83,245)	(278,971)	(35,208)	(25)	-
1080000	AC PR DPR EL PL SR	3570000	UNDERGROUND CONDUIT	SG	(1,565)	(22)	(434)	(115)	(208)	(698)	(88)	(0)	-
1080000	AC PR DPR EL PL SR	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	(3,817)	(53)	(1,059)	(280)	(508)	(1,702)	(215)	(0)	-
1080000	AC PR DPR EL PL SR	3590000	ROADS AND TRAILS	SG	(5,729)	(79)	(1,590)	(420)	(762)	(2,554)	(322)	(0)	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	CA	(688)	(688)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	IDU	(604)	-	-	-	-	-	(604)	-	-

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Depreciation Reserve (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	OR	(2,546)	-	(2,546)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	UT	(3,777)	-	-	-	-	(3,777)	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	WA	(236)	-	-	(236)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	WYP	(1,845)	-	-	-	(1,845)	-	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	WYU	(1,608)	-	-	-	(1,608)	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	CA	(2,009)	(2,009)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	IDU	(1,106)	-	-	-	-	-	(1,106)	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	OR	(10,686)	-	(10,686)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	UT	(18,754)	-	-	-	-	(18,754)	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WA	(1,915)	-	-	(1,915)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WYP	(5,430)	-	-	-	(5,430)	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WYU	(1,147)	-	-	-	(1,147)	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	CA	(11,522)	(11,522)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	IDU	(14,140)	-	-	-	-	-	(14,140)	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	OR	(111,564)	-	(111,564)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	UT	(180,067)	-	-	-	-	(180,067)	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WA	(32,273)	-	-	(32,273)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WYP	(50,470)	-	-	-	(50,470)	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WYU	(5,109)	-	-	-	(5,109)	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	(165)	(165)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	(189)	-	-	-	-	-	(189)	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	(1,617)	-	(1,617)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	(2,326)	-	-	-	-	(2,326)	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	(556)	-	-	(556)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	(915)	-	-	-	(915)	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	(58)	-	-	-	(58)	-	-	-	-
1080000	AC PR DPR EL PL SR	3631000	COMPUTER HARDWARE - DIST	CA	(24)	(24)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3631000	COMPUTER HARDWARE - DIST	IDU	(167)	-	-	-	-	-	(167)	-	-
1080000	AC PR DPR EL PL SR	3631000	COMPUTER HARDWARE - DIST	OR	(437)	-	(437)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3631000	COMPUTER HARDWARE - DIST	UT	(385)	-	-	-	-	(385)	-	-	-
1080000	AC PR DPR EL PL SR	3631000	COMPUTER HARDWARE - DIST	WA	(204)	-	-	(204)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3631000	COMPUTER HARDWARE - DIST	WYP	(509)	-	-	-	(509)	-	-	-	-
1080000	AC PR DPR EL PL SR	3631000	COMPUTER HARDWARE - DIST	WYU	(53)	-	-	-	(53)	-	-	-	-
1080000	AC PR DPR EL PL SR	3632000	COMPUTER SOFTWARE (MISC) - DIST	OR	(81)	-	(81)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3632000	COMPUTER SOFTWARE (MISC) - DIST	UT	(1)	-	-	-	-	(1)	-	-	-
1080000	AC PR DPR EL PL SR	3632000	COMPUTER SOFTWARE (MISC) - DIST	WA	(1)	-	-	(1)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3632000	COMPUTER SOFTWARE (MISC) - DIST	WYP	(50)	-	-	-	(50)	-	-	-	-
1080000	AC PR DPR EL PL SR	3632001	AFPR - AUTOMATED FACILITY POINT RECORDS	SNPD	(4,410)	(353)	(1,128)	(221)	(357)	(2,150)	(201)	-	-
1080000	AC PR DPR EL PL SR	3632004	ARCOS	SNPD	(2,398)	(192)	(613)	(120)	(194)	(1,169)	(109)	-	-
1080000	AC PR DPR EL PL SR	3632005	CADOPS - COMPUTER-ASSISTED DISTRIBUTION	SNPD	(16,796)	(1,346)	(4,296)	(843)	(1,358)	(8,188)	(764)	-	-
1080000	AC PR DPR EL PL SR	3632006	FNP - FIELDNETPRO METER READING SYSTEM	SNPD	(2,908)	(233)	(744)	(146)	(235)	(1,418)	(132)	-	-
1080000	AC PR DPR EL PL SR	3632007	FPI - FACILITIES POINTS INSPECTION	SNPD	(2,020)	(162)	(517)	(101)	(163)	(985)	(92)	-	-
1080000	AC PR DPR EL PL SR	3632008	IEE - ITRON ENTERPRISE ADDITION	CN	(4,934)	(108)	(1,487)	(339)	(341)	(2,447)	(211)	-	-
1080000	AC PR DPR EL PL SR	3632009	ITRON METER READING SOFTWARE	CN	(5,868)	(129)	(1,769)	(403)	(406)	(2,910)	(251)	-	-
1080000	AC PR DPR EL PL SR	3632010	GWD - GRAPHICAL WORK DESIGN	SNPD	(421)	(34)	(108)	(21)	(34)	(205)	(19)	-	-
1080000	AC PR DPR EL PL SR	3633000	COMMUNICATION EQUIPMENT - DIST	CA	(3,621)	(3,621)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3633000	COMMUNICATION EQUIPMENT - DIST	IDU	(4,259)	-	-	-	-	-	(4,259)	-	-
1080000	AC PR DPR EL PL SR	3633000	COMMUNICATION EQUIPMENT - DIST	OR	(27,192)	-	(27,192)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3633000	COMMUNICATION EQUIPMENT - DIST	UT	(23,099)	-	-	-	-	(23,099)	-	-	-
1080000	AC PR DPR EL PL SR	3633000	COMMUNICATION EQUIPMENT - DIST	WA	(4,368)	-	-	(4,368)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3633000	COMMUNICATION EQUIPMENT - DIST	WYP	(9,671)	-	-	-	(9,671)	-	-	-	-
1080000	AC PR DPR EL PL SR	3633000	COMMUNICATION EQUIPMENT - DIST	WYU	(1,811)	-	-	-	(1,811)	-	-	-	-
1080000	AC PR DPR EL PL SR	3633005	COMM EQUIP - MOBILE RADIOS - DIST	CA	(6)	(6)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3633005	COMM EQUIP - MOBILE RADIOS - DIST	IDU	(32)	-	-	-	-	-	(32)	-	-
1080000	AC PR DPR EL PL SR	3633005	COMM EQUIP - MOBILE RADIOS - DIST	OR	(14)	-	(14)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3633005	COMM EQUIP - MOBILE RADIOS - DIST	UT	(113)	-	-	-	-	(113)	-	-	-

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(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3633005	COMM EQUIP - MOBILE RADIOS - DIST	WA	(1)	-	-	(1)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3633005	COMM EQUIP - MOBILE RADIOS - DIST	WYP	(40)	-	-	-	(40)	-	-	-	-
1080000	AC PR DPR EL PL SR	3633005	COMM EQUIP - MOBILE RADIOS - DIST	WYU	(10)	-	-	-	(10)	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	CA	(51,224)	(51,224)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	IDU	(55,592)	-	-	-	-	-	(55,592)	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	OR	(283,867)	-	(283,867)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	UT	(190,047)	-	-	-	-	(190,047)	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WA	(87,420)	-	-	(87,420)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WYP	(85,655)	-	-	-	(85,655)	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WYU	(18,494)	-	-	-	(18,494)	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	(22,775)	(22,775)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	(18,352)	-	-	-	-	-	(18,352)	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	(149,168)	-	(149,168)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	(95,704)	-	-	-	-	(95,704)	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	(42,974)	-	-	(42,974)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	(49,434)	-	-	-	(49,434)	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	(6,573)	-	-	-	(6,573)	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	CA	(11,815)	(11,815)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	IDU	(5,608)	-	-	-	-	-	(5,608)	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	OR	(54,362)	-	(54,362)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	UT	(102,980)	-	-	-	-	(102,980)	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WA	(13,131)	-	-	(13,131)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WYP	(14,114)	-	-	-	(14,114)	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WYU	(3,521)	-	-	-	(3,521)	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	(12,771)	(12,771)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	(14,925)	-	-	-	-	-	(14,925)	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	(108,314)	-	(108,314)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	(240,532)	-	-	-	-	(240,532)	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	(16,436)	-	-	(16,436)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	(29,881)	-	-	-	(29,881)	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	(15,605)	-	-	-	(15,605)	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	CA	(30,212)	(30,212)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	IDU	(38,006)	-	-	-	-	-	(38,006)	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	OR	(272,019)	-	(272,019)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	UT	(195,489)	-	-	-	-	(195,489)	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WA	(72,707)	-	-	(72,707)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WYP	(56,038)	-	-	-	(56,038)	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WYU	(8,716)	-	-	-	(8,716)	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	CA	(5,366)	(5,366)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	IDU	(5,475)	-	-	-	-	-	(5,475)	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	OR	(51,887)	-	(51,887)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	UT	(46,882)	-	-	-	-	(46,882)	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WA	(11,204)	-	-	(11,204)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WYP	(8,700)	-	-	-	(8,700)	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WYU	(1,517)	-	-	-	(1,517)	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	CA	(9,768)	(9,768)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	IDU	(17,291)	-	-	-	-	-	(17,291)	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	OR	(115,654)	-	(115,654)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	UT	(99,971)	-	-	-	-	(99,971)	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WA	(28,161)	-	-	(28,161)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WYP	(25,040)	-	-	-	(25,040)	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WYU	(7,488)	-	-	-	(7,488)	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	CA	(3,081)	(3,081)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	IDU	(4,611)	-	-	-	-	-	(4,611)	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	OR	(43,011)	-	(43,011)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	UT	(61,380)	-	-	-	-	(61,380)	-	-	-

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(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3700000	METERS	WA	(10,420)	-	-	(10,420)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	WYP	(10,174)	-	-	-	(10,174)	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	WYU	(2,026)	-	-	-	(2,026)	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	CA	(225)	(225)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	(130)	-	-	-	-	-	(130)	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	OR	(2,111)	-	(2,111)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	UT	(3,403)	-	-	-	-	(3,403)	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WA	(431)	-	-	(431)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	(870)	-	-	-	(870)	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	(148)	-	-	-	(148)	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	(584)	(584)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	(480)	-	-	-	-	-	(480)	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	(12,321)	-	(12,321)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	(13,092)	-	-	-	-	(13,092)	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	(1,742)	-	-	(1,742)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	(4,359)	-	-	-	(4,359)	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	(1,308)	-	-	-	(1,308)	-	-	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	IDU	(3)	-	-	-	-	-	(3)	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	OR	(0)	-	(0)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	SG	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	SO	(14)	(0)	(4)	(1)	(2)	(6)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	UT	(29)	-	-	-	-	(29)	-	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	WYP	(14)	-	-	-	(14)	-	-	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	WYU	(6)	-	-	-	(6)	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	CA	(1,137)	(1,137)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	CN	(3,263)	(72)	(983)	(224)	(226)	(1,618)	(140)	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	IDU	(6,043)	-	-	-	-	-	(6,043)	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	OR	(13,117)	-	(13,117)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SE	(322)	(4)	(86)	(22)	(46)	(145)	(19)	(0)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SG	(3,702)	(51)	(1,027)	(272)	(492)	(1,650)	(208)	(0)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SO	(40,010)	(1,213)	(11,166)	(2,808)	(4,861)	(17,809)	(2,151)	(1)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	UT	(17,644)	-	-	-	-	(17,644)	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WA	(8,648)	-	-	(8,648)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WYP	(2,675)	-	-	-	(2,675)	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WYU	(1,792)	-	-	-	(1,792)	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	CA	(90)	(90)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	CN	(238)	(5)	(72)	(16)	(16)	(118)	(10)	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	IDU	(26)	-	-	-	-	-	(26)	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	OR	(812)	-	(812)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SE	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SG	(1,056)	(15)	(293)	(77)	(140)	(471)	(59)	(0)	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SO	(6,527)	(198)	(1,822)	(458)	(793)	(2,905)	(351)	(0)	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	UT	(483)	-	-	-	-	(483)	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WA	(35)	-	-	(35)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WYP	(259)	-	-	-	(259)	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WYU	(19)	-	-	-	(19)	-	-	-	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	CN	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	SG	(6)	(0)	(2)	(0)	(1)	(3)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	SO	(311)	(9)	(87)	(22)	(38)	(138)	(17)	(0)	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	UT	(1)	-	-	-	-	(1)	-	-	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	WYU	(8)	-	-	-	(8)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	CA	(43)	(43)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	IDU	(135)	-	-	-	-	-	(135)	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	(868)	-	(868)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SE	(24)	(0)	(6)	(2)	(3)	(11)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	(345)	(5)	(96)	(25)	(46)	(154)	(19)	(0)	-

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	(335)	(10)	(93)	(23)	(41)	(149)	(18)	(0)	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	(1,891)	-	-	-	-	(1,891)	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	(158)	-	-	(158)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	(363)	-	-	-	(363)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	OR	(146)	-	(146)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	SO	(114)	(3)	(32)	(8)	(14)	(51)	(6)	(0)	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	UT	(332)	-	-	-	-	(332)	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	WYP	(21)	-	-	-	(21)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	(231)	(231)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	(482)	-	-	-	-	-	(482)	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	(3,311)	-	(3,311)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	(64)	(1)	(17)	(4)	(9)	(29)	(4)	(0)	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	(5,431)	(75)	(1,507)	(398)	(723)	(2,421)	(306)	(0)	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	(699)	(21)	(195)	(49)	(85)	(311)	(38)	(0)	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	(5,308)	-	-	-	-	(5,308)	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	(957)	-	-	(957)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	(1,385)	-	-	-	(1,385)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	(252)	-	-	-	(252)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	(488)	(488)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	(1,582)	-	-	-	-	-	(1,582)	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	(7,992)	-	(7,992)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	(17)	(0)	(5)	(1)	(2)	(8)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	(4,652)	(64)	(1,291)	(341)	(619)	(2,074)	(262)	(0)	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	(304)	(9)	(85)	(21)	(37)	(135)	(16)	(0)	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	(12,470)	-	-	-	-	(12,470)	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	(1,698)	-	-	(1,698)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	(2,913)	-	-	-	(2,913)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	(696)	-	-	-	(696)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	OR	(252)	-	(252)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	SE	(4)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	SG	(3,034)	(42)	(842)	(223)	(404)	(1,353)	(171)	(0)	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	UT	(89)	-	-	-	-	(89)	-	-	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	WA	(17)	-	-	(17)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	CA	(287)	(287)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	IDU	(648)	-	-	-	-	-	(648)	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	OR	(2,040)	-	(2,040)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	SE	(39)	(0)	(10)	(3)	(6)	(17)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	SG	(997)	(14)	(277)	(73)	(133)	(445)	(56)	(0)	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	SO	(398)	(12)	(111)	(28)	(48)	(177)	(21)	(0)	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	UT	(4,922)	-	-	-	-	(4,922)	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	WA	(404)	-	-	(404)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	WYP	(2,011)	-	-	-	(2,011)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	WYU	(440)	-	-	-	(440)	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	(125)	(125)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	(78)	-	-	-	-	-	(78)	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	(365)	-	(365)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SE	(6)	(0)	(2)	(0)	(1)	(3)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	(843)	(12)	(234)	(62)	(112)	(376)	(47)	(0)	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	(49)	(1)	(14)	(3)	(6)	(22)	(3)	(0)	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	(353)	-	-	-	-	(353)	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	(73)	-	-	(73)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYP	(190)	-	-	-	(190)	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	(56)	-	-	-	(56)	-	-	-	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	(306)	-	(306)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	(336)	(5)	(93)	(25)	(45)	(150)	(19)	(0)	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	(109)	(3)	(30)	(8)	(13)	(48)	(6)	(0)	-

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Depreciation Reserve (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	(1,204)	-	-	-	-	(1,204)	-	-	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	(111)	-	-	(111)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	WYP	(150)	-	-	-	(150)	-	-	-	-
1080000	AC PR DPR EL PL SR	3923000	TRANSPORTATION EQUIPMENT	SO	(1,831)	(56)	(511)	(129)	(222)	(815)	(98)	(0)	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	CA	(58)	(58)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	IDU	(420)	-	-	-	-	-	(420)	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	OR	(1,463)	-	(1,463)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	SG	(3,715)	(51)	(1,031)	(273)	(494)	(1,656)	(209)	(0)	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	SO	(144)	(4)	(40)	(10)	(17)	(64)	(8)	(0)	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	UT	(2,081)	-	-	-	-	(2,081)	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	WA	(474)	-	-	(474)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	WYP	(616)	-	-	-	(616)	-	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	WYU	(1)	-	-	-	(1)	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	(513)	(513)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	(1,357)	-	-	-	-	-	(1,357)	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	(5,913)	-	(5,913)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	(92)	(1)	(25)	(6)	(13)	(41)	(6)	(0)	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	(11,993)	(166)	(3,329)	(880)	(1,596)	(5,347)	(675)	(0)	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	(1,213)	(37)	(338)	(85)	(147)	(540)	(65)	(0)	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	(8,412)	-	-	-	-	(8,412)	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	(1,509)	-	-	(1,509)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	(2,191)	-	-	-	(2,191)	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	(201)	-	-	-	(201)	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	CA	(296)	(296)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	IDU	(917)	-	-	-	-	-	(917)	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	OR	(5,535)	-	(5,535)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SE	(755)	(9)	(203)	(51)	(108)	(339)	(45)	(0)	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SG	(2,827)	(39)	(785)	(207)	(376)	(1,261)	(159)	(0)	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SO	(2,470)	(75)	(689)	(173)	(300)	(1,100)	(133)	(0)	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	UT	(5,127)	-	-	-	-	(5,127)	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WA	(930)	-	-	(930)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WYP	(1,750)	-	-	-	(1,750)	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WYU	(41)	-	-	-	(41)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	CA	(1,661)	(1,661)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	IDU	(1,838)	-	-	-	-	-	(1,838)	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	OR	(10,321)	-	(10,321)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SG	(182)	(3)	(50)	(13)	(24)	(81)	(10)	(0)	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SO	(1,389)	(42)	(388)	(97)	(169)	(618)	(75)	(0)	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	UT	(11,542)	-	-	-	-	(11,542)	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WA	(2,191)	-	-	(2,191)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYP	(4,781)	-	-	-	(4,781)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYU	(625)	-	-	-	(625)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	(97)	-	-	-	-	-	(97)	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	(559)	-	(559)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	(100)	(1)	(28)	(7)	(13)	(44)	(6)	(0)	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	(406)	-	-	-	-	(406)	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	(709)	(709)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	(1,834)	-	-	-	-	-	(1,834)	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	(5,522)	-	(5,522)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	(675)	(9)	(187)	(50)	(90)	(301)	(38)	(0)	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	(1,187)	(36)	(331)	(83)	(144)	(528)	(64)	(0)	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	(7,221)	-	-	-	-	(7,221)	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	(1,272)	-	-	(1,272)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	(1,844)	-	-	-	(1,844)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	(395)	-	-	-	(395)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	OR	(362)	-	(362)	-	-	-	-	-	-

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Depreciation Reserve (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3961000	CRANES	SG	(1,728)	(24)	(480)	(127)	(230)	(771)	(97)	(0)	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	UT	(199)	-	-	-	-	(199)	-	-	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	WYP	(89)	-	-	-	(89)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	OR	(573)	-	(573)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SG	(7,719)	(107)	(2,143)	(566)	(1,027)	(3,442)	(434)	(0)	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	(1,095)	-	-	-	-	(1,095)	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WA	(61)	-	-	(61)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	(267)	-	-	-	(267)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	(651)	(651)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	(1,340)	-	-	-	-	-	(1,340)	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	(5,008)	-	(5,008)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	(225)	(3)	(62)	(17)	(30)	(100)	(13)	(0)	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	(847)	(26)	(236)	(59)	(103)	(377)	(46)	(0)	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	(7,501)	-	-	-	-	(7,501)	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	(1,051)	-	-	(1,051)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	(1,817)	-	-	-	(1,817)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	(302)	-	-	-	(302)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOW	CA	(359)	(359)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOW	IDU	(802)	-	-	-	-	-	(802)	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOW	OR	(1,621)	-	(1,621)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOW	SE	(63)	(1)	(17)	(4)	(9)	(28)	(4)	(0)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOW	SG	(3,589)	(50)	(996)	(263)	(477)	(1,600)	(202)	(0)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOW	SO	(370)	(11)	(103)	(26)	(45)	(164)	(20)	(0)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOW	UT	(3,429)	-	-	-	-	(3,429)	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOW	WA	(441)	-	-	(441)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOW	WYP	(1,123)	-	-	-	(1,123)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOW	WYU	(238)	-	-	-	(238)	-	-	-	-
1080000	AC PR DPR EL PL SR	3971001	COMPUTER HARDWARE - GENERAL	CN	(1,089)	(24)	(328)	(75)	(75)	(540)	(47)	-	-
1080000	AC PR DPR EL PL SR	3971001	COMPUTER HARDWARE - GENERAL	SE	(9)	(0)	(3)	(1)	(1)	(4)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3971001	COMPUTER HARDWARE - GENERAL	SO	(34,327)	(1,041)	(9,580)	(2,409)	(4,171)	(15,279)	(1,846)	(1)	-
1080000	AC PR DPR EL PL SR	3971001	COMPUTER HARDWARE - GENERAL	UT	(3)	-	-	-	-	(3)	-	-	-
1080000	AC PR DPR EL PL SR	3972001	COMPUTER SOFTWARE (MISC) - GENERAL	CN	(7)	(0)	(2)	(0)	(0)	(3)	(0)	-	-
1080000	AC PR DPR EL PL SR	3972001	COMPUTER SOFTWARE (MISC) - GENERAL	SE	(9)	(0)	(2)	(1)	(1)	(4)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3972001	COMPUTER SOFTWARE (MISC) - GENERAL	SO	(17,348)	(526)	(4,842)	(1,218)	(2,108)	(7,722)	(933)	(0)	-
1080000	AC PR DPR EL PL SR	3972002	RWT - RCMS WORK TRACKING	SO	(11,249)	(341)	(3,140)	(790)	(1,367)	(5,007)	(605)	(0)	-
1080000	AC PR DPR EL PL SR	3972003	SAP - SAP	SO	(180,818)	(5,482)	(50,464)	(12,691)	(21,969)	(80,484)	(9,722)	(5)	-
1080000	AC PR DPR EL PL SR	3972004	VMWARE	SO	(3,721)	(113)	(1,038)	(261)	(452)	(1,656)	(200)	(0)	-
1080000	AC PR DPR EL PL SR	3972005	AUGMENTED REALITY	SO	(4,570)	(139)	(1,275)	(321)	(555)	(2,034)	(246)	(0)	-
1080000	AC PR DPR EL PL SR	3972008	FMS - FUEL MANAGEMENT SYSTEM	SO	(3,293)	(100)	(919)	(231)	(400)	(1,466)	(177)	(0)	-
1080000	AC PR DPR EL PL SR	3972011	CSS - CUSTOMER SERVICE SYSTEM	CN	(147,367)	(3,234)	(44,416)	(10,123)	(10,195)	(73,083)	(6,315)	-	-
1080000	AC PR DPR EL PL SR	3972013	NODAL PRICING SOFTWARE	SG	(2,757)	(38)	(765)	(202)	(367)	(1,229)	(155)	(0)	-
1080000	AC PR DPR EL PL SR	3972014	ESM-IRP	SO	(2,992)	(91)	(835)	(210)	(364)	(1,332)	(161)	(0)	-
1080000	AC PR DPR EL PL SR	3972015	CELONIS	SO	(3,690)	(112)	(1,030)	(259)	(448)	(1,643)	(198)	(0)	-
1080000	AC PR DPR EL PL SR	3972016	IAM - SCHEDULING/TAGGING SYSTEM	SO	(967)	(29)	(270)	(68)	(117)	(430)	(52)	(0)	-
1080000	AC PR DPR EL PL SR	3972017	AZURE B2C - IDENTITY MGT	SO	(1,084)	(33)	(302)	(76)	(132)	(482)	(58)	(0)	-
1080000	AC PR DPR EL PL SR	3972018	PCI GENTRADER	SO	(1,917)	(58)	(535)	(135)	(233)	(853)	(103)	(0)	-
1080000	AC PR DPR EL PL SR	3972019	ITOA	SO	(3,108)	(94)	(867)	(218)	(378)	(1,383)	(167)	(0)	-
1080000	AC PR DPR EL PL SR	3972020	TSSA - TRUESIGHT SERVER AUTOMATION	SO	(1,110)	(34)	(310)	(78)	(135)	(494)	(60)	(0)	-
1080000	AC PR DPR EL PL SR	3972021	EDW - ENTERPRISE DATA WAREHOUSE	SO	(5,877)	(178)	(1,640)	(412)	(714)	(2,616)	(316)	(0)	-
1080000	AC PR DPR EL PL SR	3972022	SCHOOL - SUBSTATION/CIRCUIT HISTORY OF O	SO	(2,416)	(73)	(674)	(170)	(294)	(1,075)	(130)	(0)	-
1080000	AC PR DPR EL PL SR	3972023	AMBIENT AI	SO	(60)	(2)	(17)	(4)	(7)	(27)	(3)	(0)	-
1080000	AC PR DPR EL PL SR	3972024	GRID - NET POWER COST MODELING	SO	(8,999)	(273)	(2,511)	(632)	(1,093)	(4,005)	(484)	(0)	-
1080000	AC PR DPR EL PL SR	3972025	MOIP - MID_OFFICE IMPROVEMENT PROJECT -	SO	(10,577)	(321)	(2,952)	(742)	(1,285)	(4,708)	(569)	(0)	-
1080000	AC PR DPR EL PL SR	3972026	SETTLECORE	SG	(373)	(5)	(103)	(27)	(50)	(166)	(21)	(0)	-
1080000	AC PR DPR EL PL SR	3972027	PADMS - POLE ATTACHMENT MANAGEMENT SYSTE	SO	(1,915)	(58)	(534)	(134)	(233)	(852)	(103)	(0)	-
1080000	AC PR DPR EL PL SR	3972028	SPS-MOBILE WORK MGT/MOBILITY-CLICK/SINGL	SO	(13,486)	(409)	(3,764)	(947)	(1,639)	(6,003)	(725)	(0)	-

PACIFICORP

Depreciation Reserve (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3972029	TIBCO - CONTENT MANAGEMENT SYSTEM	SO	(7,830)	(237)	(2,185)	(550)	(951)	(3,485)	(421)	(0)	-
1080000	AC PR DPR EL PL SR	3972030	TWBS - TRANSMISSION WHOLESALE BILLING SY	SG	(1,600)	(22)	(444)	(117)	(213)	(713)	(90)	(0)	-
1080000	AC PR DPR EL PL SR	3972031	UII - UTILITY INTERNATIONAL FORECASTING	SO	(7,868)	(239)	(2,196)	(552)	(956)	(3,502)	(423)	(0)	-
1080000	AC PR DPR EL PL SR	3972032	CUSTSTMT-CUSTOMER STATEMENT FORMATTING	CN	(2,629)	(58)	(792)	(181)	(182)	(1,304)	(113)	-	-
1080000	AC PR DPR EL PL SR	3972033	WEB - WEB INFRASTRUCTURE AND APPLICATION	SO	(12,006)	(364)	(3,351)	(843)	(1,459)	(5,344)	(646)	(0)	-
1080000	AC PR DPR EL PL SR	3972034	FILENET P8 DOCUMENT MANAGEMENT	SO	(7,015)	(213)	(1,958)	(492)	(852)	(3,122)	(377)	(0)	-
1080000	AC PR DPR EL PL SR	3972035	VERVE OPERATIONAL TECHNOLOGY SYSTEM	SG	(130)	(2)	(36)	(10)	(17)	(58)	(7)	(0)	-
1080000	AC PR DPR EL PL SR	3972036	ARCFM SOFTWARE	SO	(3,978)	(121)	(1,110)	(279)	(483)	(1,771)	(214)	(0)	-
1080000	AC PR DPR EL PL SR	3972039	AMI METERING SOFTWARE	CN	(34,927)	(767)	(10,527)	(2,399)	(2,416)	(17,321)	(1,497)	-	-
1080000	AC PR DPR EL PL SR	3972040	BIG DATA & ANALYTICS	SO	(6,338)	(192)	(1,769)	(445)	(770)	(2,821)	(341)	(0)	-
1080000	AC PR DPR EL PL SR	3972041	CES - CUSTOMER EXPERIENCE SYSTEM	CN	(9,540)	(209)	(2,875)	(655)	(660)	(4,731)	(409)	-	-
1080000	AC PR DPR EL PL SR	3972042	MAPAPPS - MAPPING SYSTEMS APPLICATION	SO	(6,919)	(210)	(1,931)	(486)	(841)	(3,080)	(372)	(0)	-
1080000	AC PR DPR EL PL SR	3972043	CUSTOMER CONTACTS	CN	(3,219)	(71)	(970)	(221)	(223)	(1,596)	(138)	-	-
1080000	AC PR DPR EL PL SR	3972045	C&T - ENERGY TRADING SYSTEM	SO	(19,916)	(604)	(5,558)	(1,398)	(2,420)	(8,865)	(1,071)	(1)	-
1080000	AC PR DPR EL PL SR	3972046	CYME GATEWAY	SO	(923)	(28)	(258)	(65)	(112)	(411)	(50)	(0)	-
1080000	AC PR DPR EL PL SR	3972047	M365	SO	(3,001)	(91)	(837)	(211)	(365)	(1,336)	(161)	(0)	-
1080000	AC PR DPR EL PL SR	3972048	ADS	SO	(1,276)	(39)	(356)	(90)	(155)	(568)	(69)	(0)	-
1080000	AC PR DPR EL PL SR	3972049	TECHNOSYLVA	SO	(4,525)	(137)	(1,263)	(318)	(550)	(2,014)	(243)	(0)	-
1080000	AC PR DPR EL PL SR	3972050	SITUATIONAL AWARENESS	SO	(775)	(23)	(216)	(54)	(94)	(345)	(42)	(0)	-
1080000	AC PR DPR EL PL SR	3972051	MAXIMO	SO	(6,052)	(183)	(1,689)	(425)	(735)	(2,694)	(325)	(0)	-
1080000	AC PR DPR EL PL SR	3972052	AURORA	SO	(1,098)	(33)	(306)	(77)	(133)	(489)	(59)	(0)	-
1080000	AC PR DPR EL PL SR	3972053	CXP - CUSTOMER EXPERIENCE (CX) PLATFORM	CN	(1,237)	(27)	(373)	(85)	(86)	(613)	(53)	-	-
1080000	AC PR DPR EL PL SR	3972054	SOLARWINDS	SG	(39)	(1)	(11)	(3)	(5)	(18)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3972055	APIM - ASSET PERFORMANCE & INVESTMENT MA	SO	(1,927)	(58)	(538)	(135)	(234)	(858)	(104)	(0)	-
1080000	AC PR DPR EL PL SR	3972056	ENTERPRISE GEOGRAPHIC INFORMATION SYSTEM	SO	(416)	(13)	(116)	(29)	(51)	(185)	(22)	(0)	-
1080000	AC PR DPR EL PL SR	3972057	FOUNDRY	SO	(10,145)	(308)	(2,831)	(712)	(1,233)	(4,516)	(545)	(0)	-
1080000	AC PR DPR EL PL SR	3972058	PSP - PUBLIC SAFETY PORTAL	SO	(2,822)	(86)	(788)	(198)	(343)	(1,256)	(152)	(0)	-
1080000	AC PR DPR EL PL SR	3972059	ACD–CALL CENTER AUTOMATED CALL DISTRIBUT	CN	(4,132)	(91)	(1,245)	(284)	(286)	(2,049)	(177)	-	-
1080000	AC PR DPR EL PL SR	3973001	COMMUNICATION EQUIPMENT - GENERAL	CA	(15)	(15)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3973001	COMMUNICATION EQUIPMENT - GENERAL	CN	(2,095)	(46)	(632)	(144)	(145)	(1,039)	(90)	-	-
1080000	AC PR DPR EL PL SR	3973001	COMMUNICATION EQUIPMENT - GENERAL	IDU	(601)	-	-	-	-	-	(601)	-	-
1080000	AC PR DPR EL PL SR	3973001	COMMUNICATION EQUIPMENT - GENERAL	OR	(1,986)	-	(1,986)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3973001	COMMUNICATION EQUIPMENT - GENERAL	SE	(189)	(2)	(51)	(13)	(27)	(85)	(11)	(0)	-
1080000	AC PR DPR EL PL SR	3973001	COMMUNICATION EQUIPMENT - GENERAL	SG	(3,142)	(44)	(872)	(230)	(418)	(1,401)	(177)	(0)	-
1080000	AC PR DPR EL PL SR	3973001	COMMUNICATION EQUIPMENT - GENERAL	SO	(38,722)	(1,174)	(10,807)	(2,718)	(4,705)	(17,236)	(2,082)	(1)	-
1080000	AC PR DPR EL PL SR	3973001	COMMUNICATION EQUIPMENT - GENERAL	UT	(5,133)	-	-	-	-	(5,133)	-	-	-
1080000	AC PR DPR EL PL SR	3973001	COMMUNICATION EQUIPMENT - GENERAL	WA	(28)	-	-	(28)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3973001	COMMUNICATION EQUIPMENT - GENERAL	WYP	(27)	-	-	-	(27)	-	-	-	-
1080000	AC PR DPR EL PL SR	3973001	COMMUNICATION EQUIPMENT - GENERAL	WYU	(1,718)	-	-	-	(1,718)	-	-	-	-
1080000	AC PR DPR EL PL SR	3973005	COMM EQUIP - MOBILE RADIOS - GENERAL	SO	(18)	(1)	(5)	(1)	(2)	(8)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3973005	COMM EQUIP - MOBILE RADIOS - GENERAL	UT	(6)	-	-	-	-	(6)	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	CA	(41)	(41)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	CN	(42)	(1)	(13)	(3)	(3)	(21)	(2)	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	IDU	(40)	-	-	-	-	-	(40)	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	OR	(817)	-	(817)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SE	(3)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SG	(1,709)	(24)	(474)	(125)	(227)	(762)	(96)	(0)	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SO	(847)	(26)	(236)	(59)	(103)	(377)	(46)	(0)	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	UT	(875)	-	-	-	-	(875)	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WA	(129)	-	-	(129)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WYP	(109)	-	-	-	(109)	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WYU	(17)	-	-	-	(17)	-	-	-	-
1080000 Total					**(13,232,758)**	**(314,580)**	**(3,920,533)**	**(1,028,018)**	**(1,684,249)**	**(5,563,361)**	**(721,653)**	**(364)**	**-**
1083000	AC PR DPR-REMOVAL	288351	REG LIAB - STEAM DECOMM - ID	IDU	(8,297)	-	-	-	-	-	(8,297)	-	-
1083000	AC PR DPR-REMOVAL	288353	REG LIAB - STEAM DECOMM - UT	UT	(76,741)	-	-	-	-	(76,741)	-	-	-
1083000	AC PR DPR-REMOVAL	288355	REG LIAB - STEAM DECOMM - WY	WYP	(22,675)	-	-	-	(22,675)	-	-	-	-

PACIFICORP

Depreciation Reserve (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1083000	AC PR DPR-REMOVAL	288361	Reg Liab - Steam Decomm - CA	CA	(1,857)	(1,857)	-	-	-	-	-	-	-
1083000	AC PR DPR-REMOVAL	288362	Reg Liab - Steam Decomm - OR	OR	(1,071)	-	(1,071)	-	-	-	-	-	-
1083000	AC PR DPR-REMOVAL	288365	Reg Liab - Steam Decomm - WA	WA	(16,063)	-	-	(16,063)	-	-	-	-	-
1083000 Total					**(126,705)**	**(1,857)**	**(1,071)**	**(16,063)**	**(22,675)**	**(76,741)**	**(8,297)**	**-**	**-**
1085000	AC PR DPR-ACCRUAL	145129	BUILDINGS - ACCUMULATED DEPRECIATION-NON	SO	2,268	69	633	159	276	1,009	122	0	-
1085000	AC PR DPR-ACCRUAL	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-P	(3,043)	(42)	(845)	(223)	(405)	(1,357)	(171)	(0)	-
1085000	AC PR DPR-ACCRUAL	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-U	(849)	(12)	(236)	(62)	(113)	(379)	(48)	(0)	-
1085000	AC PR DPR-ACCRUAL	145139	PRODUCTION PLANT-ACCUM DEPRECIATION	SG	21,447	297	5,953	1,573	2,853	9,562	1,207	1	-
1085000	AC PR DPR-ACCRUAL	145149	TRANSMISSION PLANT ACCUMULATED DEPR NON-	SG	5,648	78	1,568	414	752	2,518	318	0	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	CA	264	264	-	-	-	-	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	IDU	135	-	-	-	-	-	135	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	OR	1,461	-	1,461	-	-	-	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	UT	3,155	-	-	-	-	3,155	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WA	294	-	-	294	-	-	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WYU	325	-	-	-	325	-	-	-	-
1085000 Total					**31,104**	**654**	**8,534**	**2,155**	**3,688**	**14,510**	**1,562**	**1**	**-**
Grand Total					**(13,328,358)**	**(315,782)**	**(3,913,070)**	**(1,041,926)**	**(1,703,237)**	**(5,625,592)**	**(728,387)**	**(363)**	**-**

B18.AMORTIZATION RESERVE

PACIFICORP

Amortization Reserve (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1110000	AC PR AMR EL PT SF	3020000	FRANCHISES AND CONSENTS	IDU	(1,000)	-	-	-	-	-	(1,000)	-	-
1110000	AC PR AMR EL PT SF	3020000	FRANCHISES AND CONSENTS	SG	(8,079)	(112)	(2,242)	(593)	(1,075)	(3,602)	(455)	(0)	-
1110000	AC PR AMR EL PT SF	3020000	FRANCHISES AND CONSENTS	SG-P	(51,048)	(708)	(14,169)	(3,745)	(6,792)	(22,761)	(2,873)	(2)	-
1110000	AC PR AMR EL PT SF	3020000	FRANCHISES AND CONSENTS	SG-U	(7,393)	(102)	(2,052)	(542)	(984)	(3,296)	(416)	(0)	-
1110000	AC PR AMR EL PT SF	3031040	INTANGIBLE PLANT	OR	(157)	-	(157)	-	-	-	-	-	-
1110000	AC PR AMR EL PT SF	3031040	INTANGIBLE PLANT	SG	(17,800)	(247)	(4,940)	(1,306)	(2,368)	(7,936)	(1,002)	(1)	-
1110000	AC PR AMR EL PT SF	3031040	INTANGIBLE PLANT	UT	(397)	-	-	-	-	(397)	-	-	-
1110000	AC PR AMR EL PT SF	3031040	INTANGIBLE PLANT	WYP	(408)	-	-	-	(408)	-	-	-	-
1110000	AC PR AMR EL PT SF	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	(123)	(2)	(34)	(9)	(16)	(55)	(7)	(0)	-
1110000	AC PR AMR EL PT SF	3032740	GADSBY INTANGIBLE ASSETS	SG	(24)	(0)	(7)	(2)	(3)	(11)	(1)	(0)	-
1110000	AC PR AMR EL PT SF	3032760	SWIFT 2 IMPROVEMENTS	SG	(9,005)	(125)	(2,499)	(661)	(1,198)	(4,015)	(507)	(0)	-
1110000	AC PR AMR EL PT SF	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	(332)	(5)	(92)	(24)	(44)	(148)	(19)	(0)	-
1110000	AC PR AMR EL PT SF	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	(79)	(1)	(22)	(6)	(11)	(35)	(4)	(0)	-
1110000	AC PR AMR EL PT SF	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG-U	(16)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
1110000	AC PR AMR EL PT SF	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSET	SG	(4,946)	(69)	(1,373)	(363)	(658)	(2,205)	(278)	(0)	-
1110000	AC PR AMR EL PT SF	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	(40,764)	(565)	(11,314)	(2,990)	(5,424)	(18,175)	(2,294)	(2)	-
1110000	AC PR AMR EL PT SF	3033380	GAS PLANT INTANGIBLES	SG	(996)	(14)	(277)	(73)	(133)	(444)	(56)	(0)	-
1110000	AC PR AMR EL PT SF	3035320	HYDRO PLANT INTANGIBLES	SG	(1,258)	(17)	(349)	(92)	(167)	(561)	(71)	(0)	-
1110000	AC PR AMR EL PT SF	3035320	HYDRO PLANT INTANGIBLES	SG-P	(175)	(2)	(49)	(13)	(23)	(78)	(10)	(0)	-
1110000	AC PR AMR EL PT SF	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	(4,394)	(61)	(1,220)	(322)	(585)	(1,959)	(247)	(0)	-
1110000	AC PR AMR EL PT SF	3380018	INVERTERS - SOLAR - LSHLD IMPRV	OR	(279)	-	(279)	-	-	-	-	-	-
1110000	AC PR AMR EL PT SF	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	(512)	(512)	-	-	-	-	-	-	-
1110000	AC PR AMR EL PT SF	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	IDU	(334)	-	-	-	-	-	(334)	-	-
1110000	AC PR AMR EL PT SF	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	(5,253)	-	(5,253)	-	-	-	-	-	-
1110000	AC PR AMR EL PT SF	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	(1,875)	(57)	(523)	(132)	(228)	(835)	(101)	(0)	-
1110000	AC PR AMR EL PT SF	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	(33)	-	-	-	-	(33)	-	-	-
1110000	AC PR AMR EL PT SF	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	(2,265)	-	-	(2,265)	-	-	-	-	-
1110000	AC PR AMR EL PT SF	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	(4,738)	-	-	-	(4,738)	-	-	-	-
1110000 Total					**(163,684)**	**(2,599)**	**(46,856)**	**(13,138)**	**(24,857)**	**(66,554)**	**(9,675)**	**(6)**	**-**
Grand Total					**(163,684)**	**(2,599)**	**(46,856)**	**(13,138)**	**(24,857)**	**(66,554)**	**(9,675)**	**(6)**	**-**

B19.D.I.T. BALANCE AND I.T.C

Investment Tax Credit Balance (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2551000	ACC DEF ITC - FED	285620	Accum Def ITC - Solar Arrays - 2013	SG	(87)	(1)	(24)	(6)	(12)	(39)	(5)	(0)	-
2551000	ACC DEF ITC - FED	285621	Accum Def ITC - Solar Arrays - 2014	SG	(60)	(1)	(17)	(4)	(8)	(27)	(3)	(0)	-
2551000	ACC DEF ITC - FED	285622	Accum Def ITC - Solar Battery	UT	(984)	-	-	-	-	(984)	-	-	-
2551000	ACC DEF ITC - FED	285623	Accum Def ITC - Solar Facility	UT	(804)	-	-	-	-	(804)	-	-	-
2551000 Total					**(1,934)**	**(2)**	**(41)**	**(11)**	**(19)**	**(1,853)**	**(8)**	**(0)**	**-**
2552000	ACC DEF ITC-IDAHO	285612	Acc Def Idaho ITC-ID situs ATL	IDU	(12)	-	-	-	-	-	(12)	-	-
2552000 Total					**(12)**	**-**	**-**	**-**	**-**	**-**	**(12)**	**-**	**-**
Grand Total					**(1,947)**	**(2)**	**(41)**	**(11)**	**(19)**	**(1,853)**	**(20)**	**(0)**	**-**

PACIFICORP

Deferred Income Tax Balance (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1900000	ACM DEF INCM TAXES	287063	DTA 705.348 - OR - Protected PP&E ARAM	OR	0	-	0	-	-	-	-	-	-
1900000	ACM DEF INCM TAXES	287065	DTA 705.350 - WA - Protected PP&E ARAM	WA	502	-	-	502	-	-	-	-	-
1900000 Total					**502**	**-**	**0**	**502**	**-**	**-**	**-**	**-**	**-**
1901000	ACCUM DEF INC TAX	286952	DTA 715.296 RL - Fly Ash - WA	OTHER	410	-	-	-	-	-	-	-	410
1901000	ACCUM DEF INC TAX	286959	DTA 610.157 RL-Plant Closure Cost - OR	OR	166	-	166	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287044	DTA 610.156 RL-Plant Closure Cost-CA	CA	234	234	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287045	DTA 610.155 RL - WA-Plant Closure Cost	WA	1,500	-	-	1,500	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287047	DTA 610.150 RL-Bridger Acc Dep&Reclm-OR	OR	4,046	-	4,046	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287048	DTA 705.425 RL-Bridger Accel Depr- WA	WA	2,648	-	-	2,648	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287049	DTA 705.352 RL-Klamath Dams Removal-CA	CA	64	64	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287055	DTA 705.344 RL-Income Tax Deferral-WA	OTHER	513	-	-	-	-	-	-	-	513
1901000	ACCUM DEF INC TAX	287060	DTA 910.242 Joint Owner Rec in Dispute	SO	600	18	167	42	73	267	32	0	-
1901000	ACCUM DEF INC TAX	287080	DTA 910.241 PMI Legal Reserve	SE	5,810	73	1,558	390	833	2,606	350	0	-
1901000	ACCUM DEF INC TAX	287081	DTA UT Govt Interest Tax Credit	SO	21	1	6	1	3	9	1	0	-
1901000	ACCUM DEF INC TAX	287111	DTA 705.287 RL - Prot PP&E EDIT - CA	CA	6,824	6,824	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287112	DTA 705.288 RL - Prot PP&E EDIT - ID	IDU	17,437	-	-	-	-	-	17,437	-	-
1901000	ACCUM DEF INC TAX	287113	DTA 705.289 RL - Prot PP&E EDIT - OR	OR	75,702	-	75,702	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287114	DTA 705.290 RL - Prot PP&E EDIT - WA	WA	15,991	-	-	15,991	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287115	DTA 705.291 RL - Prot PP&E EDIT - WY	WYP	42,807	-	-	-	42,807	-	-	-	-
1901000	ACCUM DEF INC TAX	287116	DTA 705.292 RL - Prot PP&E EDIT - UT	UT	135,508	-	-	-	-	135,508	-	-	-
1901000	ACCUM DEF INC TAX	287124	DTA 705.296 RL-NonProt PP&E EDIT-WA	WA	824	-	-	824	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287168	DTA 705.246 RL-Pension Settlement - UT	OTHER	1,128	-	-	-	-	-	-	-	1,128
1901000	ACCUM DEF INC TAX	287171	DTA 415.940 RL-Steam Decomm-CA	CA	456	456	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287172	DTA 415.941 RL-Steam Decomm-OR	OR	263	-	263	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287173	DTA 415.942 RL-Steam Decomm-WA	WA	3,949	-	-	3,949	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287174	DTA 705.410 RL-Cholla Decomm-CA	CA	(38)	(38)	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287175	DTA 705.411 RL-Cholla Decomm-ID	IDU	227	-	-	-	-	-	227	-	-
1901000	ACCUM DEF INC TAX	287176	DTA 705.412 RL-Cholla Decomm-OR	OR	330	-	330	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287177	DTA 705.413 RL-Cholla Decomm-UT	UT	1,767	-	-	-	-	1,767	-	-	-
1901000	ACCUM DEF INC TAX	287178	DTA 705.414 RL-Cholla Decomm-WY	WYP	(476)	-	-	-	(476)	-	-	-	-
1901000	ACCUM DEF INC TAX	287195	DTA 705.284 RL Excess Def Inc Taxes WA	WA	42	-	-	42	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287198	DTA 320.279 FAS 158 Post-Retirement	SO	12,673	384	3,537	889	1,540	5,641	681	0	-
1901000	ACCUM DEF INC TAX	287199	DTA 220.101 Bad Debt	BADDEBT	8	0	3	1	1	2	0	-	-
1901000	ACCUM DEF INC TAX	287200	DTA 705.267 RL-WA Decoup Mech	OTHER	273	-	-	-	-	-	-	-	273
1901000	ACCUM DEF INC TAX	287209	DTA 705.266 RL-Energy Savings Assist-CA	OTHER	152	-	-	-	-	-	-	-	152
1901000	ACCUM DEF INC TAX	287211	DTA 425.226 - Deferred Revenue Other	OTHER	1,738	-	-	-	-	-	-	-	1,738
1901000	ACCUM DEF INC TAX	287212	DTA 705.245-RL-OR Dir Acc 5 yr Opt Out	OTHER	262	-	-	-	-	-	-	-	262
1901000	ACCUM DEF INC TAX	287214	DTA 910.245 - Contra Rec Joint Owners	SO	4	0	1	0	0	2	0	0	-
1901000	ACCUM DEF INC TAX	287216	DTA 605.715 Trapper Mine Contract Oblig	SE	2,561	32	687	172	367	1,149	154	0	-
1901000	ACCUM DEF INC TAX	287219	DTA 715.810 Chehalis Mitigation Oblig	SG	58	1	16	4	8	26	3	0	-
1901000	ACCUM DEF INC TAX	287220	DTA 720.560 Pension Liab UMWA Withdraw	SE	19,634	245	5,266	1,317	2,816	8,807	1,182	1	-
1901000	ACCUM DEF INC TAX	287225	DTA 605.103 ARO/Reg Diff - Trojan - WA	WA	61	-	-	61	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287237	DTA 705.755 RL-NONCURRENT RECLASS-OTHE	OTHER	14,381	-	-	-	-	-	-	-	14,381
1901000	ACCUM DEF INC TAX	287238	DTA 705.420 RL - CA GHG Allowance Rev	OTHER	4,095	-	-	-	-	-	-	-	4,095
1901000	ACCUM DEF INC TAX	287253	DTA 705.400 Reg Lia - OR Inj & Dam Reser	OR	(847)	-	(847)	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287254	DTA 705.450 Reg Lia - CA Property Ins Re	CA	(1,119)	(1,119)	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287255	DTA 705.451 Reg Lia - OR Property Ins Re	OR	(11,985)	-	(11,985)	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287256	DTA 705.452 Reg Lia - WA Property Ins Re	WA	66	-	-	66	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287257	DTA 705.453 Reg Lia - ID Property Ins Re	IDU	162	-	-	-	-	-	162	-	-
1901000	ACCUM DEF INC TAX	287258	DTA 705.454 Reg Lia - UT Property Ins Re	UT	(430)	-	-	-	-	(430)	-	-	-
1901000	ACCUM DEF INC TAX	287259	DTA 705.455 Reg Lia - WY Property Ins Re	WYP	94	-	-	-	94	-	-	-	-
1901000	ACCUM DEF INC TAX	287270	Valuation Allowance for DTA	SO	(5,257)	(159)	(1,467)	(369)	(639)	(2,340)	(283)	(0)	-
1901000	ACCUM DEF INC TAX	287271	DTA 705.336 RL - Sale of RECs - UT	OTHER	1,505	-	-	-	-	-	-	-	1,505
1901000	ACCUM DEF INC TAX	287272	DTA 705.337 RL - Sale of RECs - WY	OTHER	302	-	-	-	-	-	-	-	302
1901000	ACCUM DEF INC TAX	287274	DTA 705.261 Reg Liab-Sale of RECs-OR	OTHER	307	-	-	-	-	-	-	-	307
1901000	ACCUM DEF INC TAX	287281	DTA - CA AMT CREDIT	OTHER	275	-	-	-	-	-	-	-	275
1901000	ACCUM DEF INC TAX	287298	DTA 205.210 ERC Impairment Reserve	SE	502	6	135	34	72	225	30	0	-
1901000	ACCUM DEF INC TAX	287299	DTA 705.265 Reg Liab-OR Energy Conservat	OTHER	2,184	-	-	-	-	-	-	-	2,184
1901000	ACCUM DEF INC TAX	287302	DTA-610.114 PMI EITF 04-06 PRE STRIPPING	SE	994	12	267	67	143	446	60	0	-
1901000	ACCUM DEF INC TAX	287304	DTA 610.146 OR REG ASSET/LIAB CONS	OR	23	-	23	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287309	DTA 705.200 Oregon Gain on Sale-Halsey	OTHER	128	-	-	-	-	-	-	-	128

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Deferred Income Tax Balance (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1901000	ACCUM DEF INC TAX	287314	DTA 415.700 Reg liability BPA balancing	OTHER	695	-	-	-	-	-	-	-	695
1901000	ACCUM DEF INC TAX	287324	DTA 720.200 Deferred Comp. Accrual - Cas	SO	1,407	43	393	99	171	626	76	0	-
1901000	ACCUM DEF INC TAX	287327	DTA 720.300 Pension/Retirement Accrual -	SO	225	7	63	16	27	100	12	0	-
1901000	ACCUM DEF INC TAX	287332	DTA 505.600 Vacation Accrual-Cash Basis	SO	9,204	279	2,569	646	1,118	4,097	495	0	-
1901000	ACCUM DEF INC TAX	287337	DTA 715.105 MCI F.O.G. WIRE LEASE	SG	122	2	34	9	16	55	7	0	-
1901000	ACCUM DEF INC TAX	287338	DTA415.110 Def Reg Asset-Transmission Sr	SG	469	7	130	34	62	209	26	0	-
1901000	ACCUM DEF INC TAX	287340	DTA 220.100 Bad Debts Allowance - Cash B	BADDEBT	5,454	289	2,330	800	381	1,547	106	-	-
1901000	ACCUM DEF INC TAX	287341	DTA 910.530 Injuries & Damages Accrual -	SO	342,345	10,380	95,545	24,028	41,594	152,381	18,407	10	-
1901000	ACCUM DEF INC TAX	287370	DTA 425.215 Unearned Joint Use Pole Cont	SNPD	199	16	51	10	16	97	9	-	-
1901000	ACCUM DEF INC TAX	287389	DTA 610.145 RL - DSM	OTHER	1,835	-	-	-	-	-	-	-	1,835
1901000	ACCUM DEF INC TAX	287415	DTA 205.200 M&S INV	SNPD	473	38	121	24	38	230	22	-	-
1901000	ACCUM DEF INC TAX	287417	DTA 605.710 ACCRUED FINAL RECLAMATION	OTHER	463	-	-	-	-	-	-	-	463
1901000	ACCUM DEF INC TAX	287430	DTA 505.125 Accrued Royalties	SE	264	3	71	18	38	119	16	0	-
1901000	ACCUM DEF INC TAX	287437	DTA Net Operating Loss Carryforwrd-State	SO	91,049	2,761	25,411	6,391	11,062	40,527	4,895	3	-
1901000	ACCUM DEF INC TAX	287441	DTA 605.100 Trojan Decom Cost-Regulatory	TROJD	1,202	16	332	87	162	536	68	0	-
1901000	ACCUM DEF INC TAX	287449	DTA Federal Detriment of State NOL	SO	(19,148)	(581)	(5,344)	(1,344)	(2,326)	(8,523)	(1,030)	(1)	-
1901000	ACCUM DEF INC TAX	287473	DTA 705.270 Reg Liab	OTHER	44	-	-	-	-	-	-	-	44
1901000	ACCUM DEF INC TAX	287474	DTA 705.271 Reg Liab	OTHER	141	-	-	-	-	-	-	-	141
1901000	ACCUM DEF INC TAX	287475	DTA 705.272 Reg Liab	OTHER	57	-	-	-	-	-	-	-	57
1901000	ACCUM DEF INC TAX	287476	DTA 705.273 Reg Liab	OTHER	1,273	-	-	-	-	-	-	-	1,273
1901000	ACCUM DEF INC TAX	287477	DTA 705.274 Reg Liab	OTHER	60	-	-	-	-	-	-	-	60
1901000	ACCUM DEF INC TAX	287478	DTA 705.275 Reg Liab	OTHER	127	-	-	-	-	-	-	-	127
1901000	ACCUM DEF INC TAX	287681	DTL 920.110 BRIDGER EXTRACTION TAXES PA	SE	333	4	89	22	48	149	20	0	-
1901000	ACCUM DEF INC TAX	287706	DTL 610.100 COAL MINE DEVT PMI	SE	(506)	(6)	(136)	(34)	(73)	(227)	(30)	(0)	-
1901000	ACCUM DEF INC TAX	287720	DTL 610.100 PMI DEV'T COST AMORT	SE	145	2	39	10	21	65	9	0	-
1901000	ACCUM DEF INC TAX	287722	DTL 505.510 PMI VAC ACCRUAL	SE	108	1	29	7	16	49	7	0	-
1901000	ACCUM DEF INC TAX	287723	DTL 205.411 PMI SEC. 263A	SE	856	11	230	57	123	384	52	0	-
1901000	ACCUM DEF INC TAX	287726	DTL PMI PP&E	SE	(5,897)	(74)	(1,582)	(396)	(846)	(2,645)	(355)	(0)	-
1901000	ACCUM DEF INC TAX	287735	DTL 910.905 PMI COST DEPLETION	SE	(127)	(2)	(34)	(9)	(18)	(57)	(8)	(0)	-
1901000	ACCUM DEF INC TAX	287937	DTA 505.601 PMI - Sick Leave Accrual	SE	3	0	1	0	0	2	0	0	-
1901000 Total					**794,435**	**20,231**	**198,215**	**58,105**	**99,271**	**343,407**	**42,842**	**13**	**32,349**
2811000	AC DEF TAX-ACCL AM	287960	DTL 105.128 Accel Depr Pollution Cntrl F	SG	(104,695)	(1,451)	(29,059)	(7,680)	(13,929)	(46,680)	(5,891)	(4)	-
2811000 Total					**(104,695)**	**(1,451)**	**(29,059)**	**(7,680)**	**(13,929)**	**(46,680)**	**(5,891)**	**(4)**	**-**
2820000	AC DEF INCTX-PROPT	287704	DTL 105.143/165 Basis Diff - Intangibles	SNP	(428)	(17)	(114)	(27)	(49)	(198)	(23)	(0)	-
2820000 Total					**(428)**	**(17)**	**(114)**	**(27)**	**(49)**	**(198)**	**(23)**	**(0)**	**-**
2821000	AC DEF TAX-UTILITY	286605	DTL 105.136 PP&E	DITBAL	88	2	23	6	11	41	5	0	(0)
2821000	AC DEF TAX-UTILITY	287071	DTL 105.270 - Inc Tax Prop Flowthru-CA	CA	(3,387)	(3,387)	-	-	-	-	-	-	-
2821000	AC DEF TAX-UTILITY	287072	DTL 105.271 - Inc Tax Prop Flowthru-ID	IDU	(1,406)	-	-	-	-	-	(1,406)	-	-
2821000	AC DEF TAX-UTILITY	287073	DTL 105.272 - Inc Tax Prop Flowthru-OR	OR	11,771	-	11,771	-	-	-	-	-	-
2821000	AC DEF TAX-UTILITY	287074	DTL 105.273 - Inc Tax Prop Flowthru-UT	UT	51,783	-	-	-	-	51,783	-	-	-
2821000	AC DEF TAX-UTILITY	287075	DTL 105.274 - Inc Tax Prop Flowthru-WA	WA	(853)	-	-	(853)	-	-	-	-	-
2821000	AC DEF TAX-UTILITY	287076	DTL 105.275 - Inc Tax Prop Flowthru-WY	WYP	(15,921)	-	-	-	(15,921)	-	-	-	-
2821000	AC DEF TAX-UTILITY	287221	DTA 415.933 RL Contra-Carbon Decomm-ID	IDU	2,040	-	-	-	-	-	2,040	-	-
2821000	AC DEF TAX-UTILITY	287222	DTA 415.934 RL Contra-Carbon Decomm-UT	UT	18,868	-	-	-	-	18,868	-	-	-
2821000	AC DEF TAX-UTILITY	287223	DTA 415.935 RL Contra-Carbon Decomm-WY	WYP	5,575	-	-	-	5,575	-	-	-	-
2821000	AC DEF TAX-UTILITY	287605	DTL PP&E Powertax	DITBAL	(3,134,621)	(68,231)	(808,074)	(215,618)	(402,131)	(1,465,092)	(176,021)	(102)	649
2821000	AC DEF TAX-UTILITY	287607	DTL PMI PP&E	SE	(936)	(12)	(251)	(63)	(134)	(420)	(56)	(0)	-
2821000	AC DEF TAX-UTILITY	287771	DTL 110.205 SRC tax depletion	SE	6	0	2	0	1	3	0	0	-
2821000	AC DEF TAX-UTILITY	287928	DTL 425.310 Hydro Relicensing Obligation	OTHER	(1,847)	-	-	-	-	-	-	-	(1,847)
2821000 Total					**(3,068,839)**	**(71,628)**	**(796,530)**	**(216,528)**	**(412,599)**	**(1,394,816)**	**(175,438)**	**(102)**	**(1,198)**
2830000	ACC DEF TAX-OTHER	287936	DTL 205.025 PMI Fuel Cost Adjustment	SE	(684)	(9)	(183)	(46)	(98)	(307)	(41)	(0)	-
2830000 Total					**(684)**	**(9)**	**(183)**	**(46)**	**(98)**	**(307)**	**(41)**	**(0)**	**-**
2831000	AC DEF IN TX UTIL	286887	DTL 320.286 RA-Pension Settlement-OR	OTHER	(2,356)	-	-	-	-	-	-	-	(2,356)
2831000	AC DEF IN TX UTIL	286889	DTL 320.288 RA-Pension Settlement-WY	WYU	(1,088)	-	-	-	(1,088)	-	-	-	-
2831000	AC DEF IN TX UTIL	286890	DTL 415.100 RA - Equity Adv Group - WA	OTHER	(259)	-	-	-	-	-	-	-	(259)
2831000	AC DEF IN TX UTIL	286891	DTL 415.943-RA-COV19 Bill Assist Prg-OR	OTHER	(1,417)	-	-	-	-	-	-	-	(1,417)
2831000	AC DEF IN TX UTIL	286894	DTL 415.261 RA-Wildland Fire Protect–UT	OTHER	(0)	-	-	-	-	-	-	-	(0)
2831000	AC DEF IN TX UTIL	286895	DTL 415.262 RA-Wildfire Mitigation-OR	OTHER	(7,299)	-	-	-	-	-	-	-	(7,299)
2831000	AC DEF IN TX UTIL	286896	DTL 415.734 RA-Cholla Unrec Plant-CA	CA	(580)	(580)	-	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	286898	DTL 415.736 RA-Cholla Unrec Plant-WY	WYP	(6,557)	-	-	-	(6,557)	-	-	-	-

PACIFICORP

Deferred Income Tax Balance (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2831000	AC DEF IN TX UTIL	286904	DTL 415.520 RA - WA Decoupling Mech	OTHER	(2,369)	-	-	-	-	-	-	-	(2,369)
2831000	AC DEF IN TX UTIL	286909	DTL 720.815 Post-Retirement Asset	SO	(16,735)	(507)	(4,671)	(1,175)	(2,033)	(7,449)	(900)	(0)	-
2831000	AC DEF IN TX UTIL	286910	DTL 415.200 RA-OR Transp Elect PilotPgm	OTHER	1,240	-	-	-	-	-	-	-	1,240
2831000	AC DEF IN TX UTIL	286911	DTL 415.430 - RA-Transp Elect Pilot-CA	OTHER	64	-	-	-	-	-	-	-	64
2831000	AC DEF IN TX UTIL	286912	DTL 415.431 - RA-Transp Elect Pilot-WA	OTHER	(85)	-	-	-	-	-	-	-	(85)
2831000	AC DEF IN TX UTIL	286913	DTL 415.720 RA-OR Community Solar	OTHER	(910)	-	-	-	-	-	-	-	(910)
2831000	AC DEF IN TX UTIL	286917	DTL 415.260 RA-Fire Risk Mitigation-CA	OTHER	(16,131)	-	-	-	-	-	-	-	(16,131)
2831000	AC DEF IN TX UTIL	286918	DTL 210.175 - Prepaid - FSA O&M - East	SG	(946)	(13)	(263)	(69)	(126)	(422)	(53)	(0)	-
2831000	AC DEF IN TX UTIL	286919	DTL 210.170 - Prepaid - FSA O&M - West	SG	(174)	(2)	(48)	(13)	(23)	(77)	(10)	(0)	-
2831000	AC DEF IN TX UTIL	286925	DTL 415.728 Contra RA-Cholla U4-OR	OTHER	(46)	-	-	-	-	-	-	-	(46)
2831000	AC DEF IN TX UTIL	286928	DTL 415.833 RA-Pension Settlement-CA	OTHER	(311)	-	-	-	-	-	-	-	(311)
2831000	AC DEF IN TX UTIL	286929	DTL 415.841 RA-Emerg Svc Prgms-BS-CA	OTHER	66	-	-	-	-	-	-	-	66
2831000	AC DEF IN TX UTIL	286930	DTL 415.426-RA-2020 GRC-AMI Meter-OR	OTHER	(513)	-	-	-	-	-	-	-	(513)
2831000	AC DEF IN TX UTIL	286933	DTL 415.645 RA-Oregon OCAT Expense Def	OTHER	33	-	-	-	-	-	-	-	33
2831000	AC DEF IN TX UTIL	286935	DTL 415.251 RA-LowCarbon Enrgy Stnds-WY	OTHER	1,007	-	-	-	-	-	-	-	1,007
2831000	AC DEF IN TX UTIL	286936	DTL 415.255 RA-Wind Test Enrgy Def - WY	WYU	(48)	-	-	-	(48)	-	-	-	-
2831000	AC DEF IN TX UTIL	286937	DTL 415.270 RA-ElectricVehChrg Infra-UT	OTHER	(104)	-	-	-	-	-	-	-	(104)
2831000	AC DEF IN TX UTIL	286938	DTL 415.646 Reg Asset - OR Metro BIT	OTHER	(0)	-	-	-	-	-	-	-	(0)
2831000	AC DEF IN TX UTIL	286941	DTL 415.440 RA-Low Income Bill Disc-OR	OTHER	(2,492)	-	-	-	-	-	-	-	(2,492)
2831000	AC DEF IN TX UTIL	286942	DTL 415.441 RA-Utility Community AG-OR	OTHER	57	-	-	-	-	-	-	-	57
2831000	AC DEF IN TX UTIL	286946	DTL 415.264 RA-OR TB Flats	OTHER	(424)	-	-	-	-	-	-	-	(424)
2831000	AC DEF IN TX UTIL	286948	DTL 415.681 Def Intervenor Funding-WA	OTHER	(53)	-	-	-	-	-	-	-	(53)
2831000	AC DEF IN TX UTIL	286949	DTL 415.305 RA-Cedar Springs II-OR	OTHER	(21)	-	-	-	-	-	-	-	(21)
2831000	AC DEF IN TX UTIL	286951	DTL 415.533 RA-GRC Memo Account-CA	CA	(2,322)	(2,322)	-	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	286955	DTL 415.265 RA-NTO Transfer Deferral	OTHER	(1,036)	-	-	-	-	-	-	-	(1,036)
2831000	AC DEF IN TX UTIL	286956	DTL 415.504 Def Insurance Premiums - ID	OTHER	(887)	-	-	-	-	-	-	-	(887)
2831000	AC DEF IN TX UTIL	286957	DTL 415.505 Def Insurance Premiums - OR	OTHER	(8,318)	-	-	-	-	-	-	-	(8,318)
2831000	AC DEF IN TX UTIL	286958	DTL 415.446 Klamath Unrec Plant-OR	OTHER	(3)	-	-	-	-	-	-	-	(3)
2831000	AC DEF IN TX UTIL	286961	DTL 415.506 RA-Def Ins Premiums-WY	OTHER	(2,924)	-	-	-	-	-	-	-	(2,924)
2831000	AC DEF IN TX UTIL	286963	DTL 415.535 RA - WBA GRC Def-UT	OTHER	(1,381)	-	-	-	-	-	-	-	(1,381)
2831000	AC DEF IN TX UTIL	287070	DTL 415.445 RA-Klamath Unrec Plant	SG	(1,840)	(26)	(511)	(135)	(245)	(820)	(104)	(0)	-
2831000	AC DEF IN TX UTIL	287326	DTA 720.500 Severance Accrual - Cash Ba	SO	(86)	(3)	(24)	(6)	(10)	(38)	(5)	(0)	-
2831000	AC DEF IN TX UTIL	287569	DTL 720.800 FAS 158 Pension Liability	SO	(21,436)	(650)	(5,983)	(1,505)	(2,604)	(9,542)	(1,153)	(1)	-
2831000	AC DEF IN TX UTIL	287570	DTL 415.701 CA Deferred Intervenor Fundi	OTHER	(114)	-	-	-	-	-	-	-	(114)
2831000	AC DEF IN TX UTIL	287571	DTL 415.702 Reg Asset-Lake Side Liq. Dam	WYU	(150)	-	-	-	(150)	-	-	-	-
2831000	AC DEF IN TX UTIL	287576	DTL 430.110 REG ASSET RECLASS	OTHER	(1,835)	-	-	-	-	-	-	-	(1,835)
2831000	AC DEF IN TX UTIL	287590	DTL 415.840 Reg Asset - Deferred OR Ind	OTHER	(43)	-	-	-	-	-	-	-	(43)
2831000	AC DEF IN TX UTIL	287591	DTL 415.301 Environmental Clean-up Accrl	WA	1,108	-	-	1,108	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287593	DTL 415.874 Deferred Net Power Costs-WY	OTHER	(23,162)	-	-	-	-	-	-	-	(23,162)
2831000	AC DEF IN TX UTIL	287596	DTL 415.892 Deferred Net Power Costs - I	OTHER	(16,219)	-	-	-	-	-	-	-	(16,219)
2831000	AC DEF IN TX UTIL	287597	DTL 415.703 Goodnoe Hills Liquidation Da	WYP	(44)	-	-	-	(44)	-	-	-	-
2831000	AC DEF IN TX UTIL	287614	DTL 430.100 Weatherization	OTHER	(86,062)	-	-	-	-	-	-	-	(86,062)
2831000	AC DEF IN TX UTIL	287634	DTL 415.300 Environmental Clean-up Accru	SO	(38,267)	(1,160)	(10,680)	(2,686)	(4,649)	(17,033)	(2,057)	(1)	-
2831000	AC DEF IN TX UTIL	287640	DTL 415.680 Deferred Intervener Funding	OTHER	50	-	-	-	-	-	-	-	50
2831000	AC DEF IN TX UTIL	287647	DTL 425.100 IDAHO DEFERRED REGULATORY E	IDU	(9)	-	-	-	-	-	(9)	-	-
2831000	AC DEF IN TX UTIL	287661	DTL 425.360 Hermiston Swap	SG	(468)	(6)	(130)	(34)	(62)	(209)	(26)	(0)	-
2831000	AC DEF IN TX UTIL	287662	DTL 210.100 Prepaid Taxes - OR PUC	OR	(1,516)	-	(1,516)	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287664	DTL 210.120 Prepaid Taxes - UT PUC	UT	(1,785)	-	-	-	-	(1,785)	-	-	-
2831000	AC DEF IN TX UTIL	287665	DTL 210.130 Prepaid Taxes - ID PUC	IDU	(97)	-	-	-	-	-	(97)	-	-
2831000	AC DEF IN TX UTIL	287669	DTL 210.180 PRE MEM	SO	(1,177)	(36)	(329)	(83)	(143)	(524)	(63)	(0)	-
2831000	AC DEF IN TX UTIL	287675	DTL 740.100 Post Merger Loss-Reacq Debt	SNP	(380)	(15)	(101)	(24)	(43)	(176)	(20)	(0)	-
2831000	AC DEF IN TX UTIL	287685	DTL 425.380 Idaho Customer Balancing Acc	OTHER	(26)	-	-	-	-	-	-	-	(26)
2831000	AC DEF IN TX UTIL	287708	DTL 210.200 PREPAID PROPERTY TAXES	GPS	(7,334)	(238)	(2,048)	(512)	(880)	(3,263)	(392)	(0)	-
2831000	AC DEF IN TX UTIL	287738	DTL 320.270 Reg Asset FAS 158 Pension	SO	(59,863)	(1,815)	(16,707)	(4,202)	(7,273)	(26,646)	(3,219)	(2)	-
2831000	AC DEF IN TX UTIL	287747	DTL 705.240 CA Energy Program	OTHER	(917)	-	-	-	-	-	-	-	(917)
2831000	AC DEF IN TX UTIL	287770	DTL 120.205 TRAPPER MINE-EQUITY EARNINGS	OTHER	(665)	-	-	-	-	-	-	-	(665)
2831000	AC DEF IN TX UTIL	287781	DTL 415.870 Def CA	OTHER	(6,092)	-	-	-	-	-	-	-	(6,092)
2831000	AC DEF IN TX UTIL	287840	DTL 415.410 RA Energy West Mining	SE	(39,537)	(494)	(10,605)	(2,652)	(5,670)	(17,734)	(2,380)	(2)	-
2831000	AC DEF IN TX UTIL	287841	DTL 415.411 ContraRA DeerCreekAband CA	CA	318	318	-	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287843	DTL 415.413 ContraRA DeerCreekAband OR	OR	151	-	151	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287845	DTL 415.415 ContraRA DeerCreekAband WA	WA	1,121	-	-	1,121	-	-	-	-	-

PACIFICORP

Deferred Income Tax Balance (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2831000	AC DEF IN TX UTIL	287846	DTL 415.416 ContraRA DeerCreekAband WY	WYU	1,285	-	-	-	1,285	-	-	-	-
2831000	AC DEF IN TX UTIL	287849	DTL 415.424 ContraRA DeerCreekAband	SE	14,328	179	3,843	961	2,055	6,427	862	1	-
2831000	AC DEF IN TX UTIL	287850	DTL 415.425 Contra RA UMWA Pension	OTHER	811	-	-	-	-	-	-	-	811
2831000	AC DEF IN TX UTIL	287855	DTL 415.421 Contra RA UMWA Pension WA	OTHER	1,381	-	-	-	-	-	-	-	1,381
2831000	AC DEF IN TX UTIL	287860	DTL 415.855 Reg Asset-CA-Jan10 Storm Cos	OTHER	(5,287)	-	-	-	-	-	-	-	(5,287)
2831000	AC DEF IN TX UTIL	287861	DTL 415.857 Reg Asset-ID-Def Overburden	OTHER	(290)	-	-	-	-	-	-	-	(290)
2831000	AC DEF IN TX UTIL	287868	DTL 415.858 Reg Asset-WY-Def Overburden	WYP	(694)	-	-	-	(694)	-	-	-	-
2831000	AC DEF IN TX UTIL	287871	DTL 415.866 Reg Asset-OR Solar Feed-In T	OTHER	(1,101)	-	-	-	-	-	-	-	(1,101)
2831000	AC DEF IN TX UTIL	287882	DTL 415.876 Deferred Net Power Costs-OR	OTHER	(47,429)	-	-	-	-	-	-	-	(47,429)
2831000	AC DEF IN TX UTIL	287889	DTL 415.883 Def of Excess RECs WY	OTHER	(63)	-	-	-	-	-	-	-	(63)
2831000	AC DEF IN TX UTIL	287896	DTL 415.875 Def Net Power Cost - UT	OTHER	(130,678)	-	-	-	-	-	-	-	(130,678)
2831000	AC DEF IN TX UTIL	287899	DTL 415.878 RA-UT Liq Damages	UT	(73)	-	-	-	-	(73)	-	-	-
2831000	AC DEF IN TX UTIL	287903	DTL 415.879 RA-Liq Damages N2-WY	WYP	(12)	-	-	-	(12)	-	-	-	-
2831000	AC DEF IN TX UTIL	287906	DTL 415.863 RA-UT Subscriber Solar Prog	UT	(423)	-	-	-	-	(423)	-	-	-
2831000	AC DEF IN TX UTIL	287907	DTL 210.185-Prepaid Aircraft Maint Cost	SG	(17)	(0)	(5)	(1)	(2)	(8)	(1)	(0)	-
2831000	AC DEF IN TX UTIL	287908	DTL 210.190 - Prepaid Water Rights	SG	(126)	(2)	(35)	(9)	(17)	(56)	(7)	(0)	-
2831000	AC DEF IN TX UTIL	287917	DTL 705.451 - RL - OR Property Ins Res	OR	(0)	-	(0)	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287935	DTL 415.936 RA - Carbon Plt Decom/Inv	SG	(22)	(0)	(6)	(2)	(3)	(10)	(1)	(0)	-
2831000	AC DEF IN TX UTIL	287942	DTL 430.112 Reg Asset - Other - Balance	OTHER	(6,497)	-	-	-	-	-	-	-	(6,497)
2831000	AC DEF IN TX UTIL	287975	DTL 415.655 RA - CA GHG Allowances	OTHER	(2,093)	-	-	-	-	-	-	-	(2,093)
2831000	AC DEF IN TX UTIL	287977	DTL 415.885 RA-NONCURRENT RECLASS-OTHE	OTHER	(14,381)	-	-	-	-	-	-	-	(14,381)
2831000	AC DEF IN TX UTIL	287981	DTL 415.920 RA-Depreciation Increase-ID	IDU	(428)	-	-	-	-	-	(428)	-	-
2831000	AC DEF IN TX UTIL	287982	DTL 415.921 RA-Depreciation Increase-UT	UT	(189)	-	-	-	-	(189)	-	-	-
2831000	AC DEF IN TX UTIL	287983	DTL 415.922 RA-Depreciation Increase-WY	WYP	(652)	-	-	-	(652)	-	-	-	-
2831000	AC DEF IN TX UTIL	287985	DTL 415.924 RA-Carbon Unrec Plant - UT	UT	(52)	-	-	-	-	(52)	-	-	-
2831000	AC DEF IN TX UTIL	287997	DTL 415.862 RA-CA Mobile Home Park Conv	OTHER	(38)	-	-	-	-	-	-	-	(38)
2831000 Total					**(574,440)**	**(7,374)**	**(49,667)**	**(9,917)**	**(29,690)**	**(80,102)**	**(10,062)**	**(5)**	**(387,622)**
Grand Total					**(2,954,148)**	**(60,248)**	**(677,337)**	**(175,591)**	**(357,094)**	**(1,178,697)**	**(148,613)**	**(99)**	**(356,471)**

B20. CUSTOMER ADVANCES

PACIFICORP

Customer Advances (Actuals)
Year End: 06/2025
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	OR	(64,843)	-	(64,843)	-	-	-	-	-	-
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	SG	(84,838)	(1,176)	(23,547)	(6,223)	(11,287)	(37,826)	(4,774)	(3)	-
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	UT	(886)	-	-	-	-	(886)	-	-	-
2520000	CUST ADV CONSTRUCT	210553	Transmission Payments Received - Capital	SG	(7,856)	(109)	(2,180)	(576)	(1,045)	(3,503)	(442)	(0)	-
2520000	CUST ADV CONSTRUCT	210556	NET METER FEES-REFUNDABLE	UT	(19)	-	-	-	-	(19)	-	-	-
2520000	CUST ADV CONSTRUCT	210556	NET METER FEES-REFUNDABLE	WA	(8)	-	-	(8)	-	-	-	-	-
2520000	CUST ADV CONSTRUCT	285460	Transm Intercon Deposits - w/3rd Party	SG	(174,583)	(2,420)	(48,456)	(12,807)	(23,228)	(77,841)	(9,824)	(7)	-
2520000 Total					**(333,032)**	**(3,705)**	**(139,027)**	**(19,614)**	**(35,560)**	**(120,075)**	**(15,040)**	**(11)**	**-**
Grand Total					**(333,032)**	**(3,705)**	**(139,027)**	**(19,614)**	**(35,560)**	**(120,075)**	**(15,040)**	**(11)**	**-**

Docket No. UE 470
Exhibit PAC/803
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Washington Service Area Transfer Impact – December 2027

May 2026

Tab 1 - Summary

PacifiCorp
OREGON
Normalized Results of Operations - Post-Service Area Transfer
Twelve Months Ending December 31, 2027

(1)	Test Period 2020 Protocol Revenue Requirement	1,916,641,740	Page 1.1
(2)	Normalized General Business Revenues	1,793,305,491	Page 1.1
(3)	2020 Protocol Price Change (Post-Service Area Transfer)	**123,336,249**	Page 1.1
(4)	2020 Protocol Price Change (Pre-Service Area Transfer)	106,039,093	Exhibit PAC/802
(5)	Service Area Transfer Incremental Price Change	**17,297,156**	

PacifiCorp
OREGON
Normalized Results of Operations - Post-Service Area Transfer
Twelve Months Ending December 31, 2027

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,793,305,491	123,336,249	1,916,641,740
3	Interdepartmental	-		
4	Special Sales	54,006,161		
5	Other Operating Revenues	85,908,037		
6	Total Operating Revenues	1,933,219,689		
7				
8	Operating Expenses:			
9	Steam Production	271,448,356		
10	Nuclear Production	-		
11	Hydro Production	14,438,443		
12	Solar Production	232,196		
13	Wind Production	9,683,058		
14	Other Renewable Production	2,032,157		
15	Other Power Supply	449,340,665		
16	Transmission	92,450,708		
17	Distribution	126,356,176		
18	Customer Accounting	33,351,555	768,568	34,120,123
19	Customer Service & Info	5,496,218		
20	Sales	-		
21	Administrative & General	145,032,355		
22				
23	Total O&M Expenses	1,149,861,887		
24				
25	Depreciation	346,611,678		
26	Amortization	49,265		
27	Taxes Other Than Income	109,475,699	3,407,156	112,882,855
28	Income Taxes - Federal	(62,880,290)	23,772,525	(39,107,766)
29	Income Taxes - State	5,073,452	5,958,026	11,031,479
30	Income Taxes - Def Net	9,465,875		
31	Investment Tax Credit Adj.	-		
32	Misc Revenue & Expense	(131,398)		
33				
34	Total Operating Expenses:	1,557,526,166	33,906,275	1,591,432,441
35				
36	Operating Rev For Return:	375,693,523	89,429,974	465,123,497
37				
38	Rate Base:			
39	Electric Plant In Service	12,017,823,879		
40	Plant Held for Future Use	-		
41	Misc Deferred Debits	90,949,364		
42	Elec Plant Acq Adj	738,446		
43	Pensions	-		
44	Prepayments	54,456,191		
45	Fuel Stock	96,294,524		
46	Material & Supplies	241,997,615		
47	Working Capital	57,975,167		
48	Weatherization Loans	-		
49	Misc Rate Base	(14,356,267)		
50				
51	Total Electric Plant:	12,545,878,921	-	12,545,878,921
52				
53	Rate Base Deductions:			
54	Accum Prov For Deprec	(5,100,447,662)		
55	Accum Prov For Amort	(45,253,009)		
56	Accum Def Income Tax	(784,729,128)		
57	Unamortized ITC	(28,075)		
58	Customer Adv For Const	(94,619,759)		
59	Customer Service Deposits	-		
60	Misc Rate Base Deductions	(364,302,321)		
61				
62	Total Rate Base Deductions	(6,389,379,954)	-	(6,389,379,954)
63				
64	Total Rate Base:	6,156,498,967	-	6,156,498,967
65				
66	Return on Rate Base	6.102%		7.555%
67				
68	Return on Equity	6.795%		9.700%
69				
70	TAX CALCULATION:			
71	Operating Revenue	327,352,560	119,160,525	446,513,085
72	Other Deductions			
73	Interest (AFUDC)	(3,023,773)	-	(3,023,773)
74	Interest	166,533,297	-	166,533,297
75	Schedule "M" Additions	344,526,161	-	344,526,161
76	Schedule "M" Deductions	416,755,833	-	416,755,833
77	Income Before Tax	91,613,363	119,160,525	210,773,888
78				
79	State Income Taxes	5,073,452	5,958,026	11,031,479
80	Taxable Income	86,539,911	113,202,499	199,742,410
81				
82	Federal Income Taxes + Other	(62,880,290)	23,772,525	(39,107,766)

Ref. Page 2.2

PacifiCorp
OREGON
Normalized Results of Operations - Post-Service Area Transfer
Twelve Months Ending December 31, 2027

Net Rate Base	$	6,156,498,967	Ref. Page 1.1
Return on Rate Base Requested		7.56%	Ref. Page 2.1
Revenues Required to Earn Requested Return		465,123,497	
Less Current Operating Revenues		(375,693,523)	
Increase to Current Revenues		89,429,974	
Net to Gross Bump-up		137.91%	
Price Change Required for Requested Return	$	123,336,249	
Requested Price Change	$	123,336,249	
Uncollectible Percent		0.623%	Ref. Page 1.3
Increased Uncollectible Expense	$	768,568	
Requested Price Change	$	123,336,249	
Franchise Tax		2.296%	Ref. Page 1.3
Revenue Tax		0.000%	Ref. Page 1.3
Resource Supplier Tax		0.106%	Ref. Page 1.3
PUC Fees Based on General Business Revenues		0.360%	Ref. Page 1.3
Increase Taxes Other Than Income	$	3,407,156	
Requested Price Change	$	123,336,249	
Uncollectible Expense		(768,568)	
Taxes Other Than Income		(3,407,156)	
Income Before Taxes	$	119,160,525	
State Effective Tax Rate		5.00%	Ref. Page 2.1
State Income Taxes	$	5,958,026	
Taxable Income	$	113,202,499	
Federal Income Tax Rate		21.00%	Ref. Page 2.1
Federal Income Taxes	$	23,772,525	
Operating Income		100.000%	
Net Operating Income		72.509%	Ref. Page 1.3
Net to Gross Bump-Up		137.91%	

PacifiCorp
OREGON
Normalized Results of Operations - Post-Service Area Transfer
Twelve Months Ending December 31, 2027

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.623%	See Note (1) Below
Taxes Other - Franchise Tax	2.296%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier	0.106%	
PUC Fees Based on General Business Revenues	0.360%	
Sub-Total	96.614%	
State Income Tax @ 4.54%	4.831%	
Sub-Total	91.784%	
Federal Income Tax @ 21.00%	19.275%	
Net Operating Income	72.509%	

(1) Uncollectible Accounts = 11,174,954 Pg 2.11, OREGON Situs from Account 904
1,793,305,491 Pg. 2.2, General Business Revenues

Pacificorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2027

	EXHIBIT PAC/802		WA_1	WA_2	WA_3	WA_4	WA_5
	TOTAL COMPANY NORMALIZED RESULTS DECEMBER 2027	OREGON ALLOCATED NORMALIZED RESULTS DECEMBER 2027	Loads Update	Other Allocation Factors Update	Current Tax Rate Update	Situs WA O&M Removal	Situs Rate Base Removal
1 Operating Revenues:							
2 General Business Revenues	6,662,182,389	1,793,305,491	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	70,898,832	54,006,161	-	-	-	-	-
5 Other Operating Revenues	285,994,780	74,085,068	4,636,970	506	-	-	22,047
6 Total Operating Revenues	7,019,076,002	1,921,396,720	4,636,970	506	-	-	22,047
7							
8 Operating Expenses:							
9 Steam Production	498,367,279	264,348,177	7,100,180	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	48,199,621	13,378,082	1,060,361	-	-	-	-
12 Solar Production	232,196	232,196	-	-	-	-	-
13 Wind Production	37,051,549	10,283,870	815,110	-	-	-	-
14 Other Renewable Production	3,122,787	1,997,903	34,254	-	-	-	-
15 Other Power Supply	833,424,602	449,391,626	2,826,168	-	-	-	-
16 Transmission	155,583,147	91,307,111	1,957,288	-	-	-	-
17 Distribution	349,264,972	125,776,662	-	-	-	-	579,514
18 Customer Accounting	100,540,869	32,131,875	-	1,219,679	-	-	-
19 Customer Service & Info	248,676,556	5,324,067	-	172,151	-	-	-
20 Sales	-	-	-	-	-	-	-
21 Administrative & General	314,131,993	140,886,076	3,146,184	31,571	-	-	1,173,078
22							
23 Total O&M Expenses	2,588,595,571	1,135,057,645	16,939,546	1,423,401	-	-	1,752,592
24							
25 Depreciation	1,235,870,409	337,794,580	19,729,311	164,035	-	-	408,100
26 Amortization	22,421,726	(295,207)	509,074	5	-	-	198
27 Taxes Other Than Income	271,441,309	112,881,934	3,111,102	29,535	-	-	1,337,973
28 Income Taxes - Federal	411,715,574	(60,628,691)	(9,823,369)	(1,496,232)	(44,401)	1,382,422	(646,946)
29 Income Taxes - State	121,278,480	5,141,589	(2,224,471)	(338,853)	211,297	346,472	(162,062)
30 Income Taxes - Def Net	(96,399,478)	9,027,360	1,273,108	1,435,235	-	(1,706,499)	(58,933)
31 Investment Tax Credit Adj.	(514)	-	-	-	-	-	-
32 Misc Revenue & Expense	(1,011,940)	(104,716)	(20,270)	(143)	-	-	(6,249)
33							
34 Total Operating Expenses:	4,553,911,138	1,538,874,495	29,494,032	1,216,982	166,896	22,395	2,624,672
35							
36 Operating Rev For Return:	2,465,164,863	382,522,225	(24,857,062)	(1,216,476)	(166,896)	(22,395)	(2,602,625)
37							
38 Rate Base:							
39 Electric Plant In Service	42,016,634,369	11,726,376,909	636,552,127	5,568,629	-	-	6,098,470
40 Plant Held for Future Use	-	-	-	-	-	-	-
41 Misc Deferred Debits	1,674,027,413	93,002,614	6,386,655	15,601	-	-	680,279
42 Elec Plant Acq Adj	11,124,844	684,215	54,232	-	-	-	-
43 Pension	-	-	-	-	-	-	-
44 Prepayments	174,702,384	51,058,541	2,482,571	20,452	-	-	891,827
45 Fuel Stock	334,920,385	89,834,980	6,459,544	-	-	-	-
46 Material & Supplies	671,506,101	239,908,978	3,464,279	(368)	-	-	(37,911)
47 Working Capital	154,423,410	62,523,353	1,315,446	7,855	5,064	52,457	917,333
48 Weatherization Loans	350,500,629	-	-	-	-	-	-
49 Misc Rate Base	(14,356,267)	(14,356,267)	-	-	-	-	-
50							
51 Total Electric Plant:	45,373,483,268	12,249,033,325	656,714,853	5,612,171	5,064	52,457	8,549,998
52							
53 Rate Base Deductions:							
54 Accum Prov For Deprec	(16,533,503,057)	(4,896,570,165)	(253,851,367)	(5,258,664)	-	-	(3,868,254)
55 Accum Prov For Amort	(158,023,373)	(45,207,495)	(3,278,592)	72,258	-	-	69,145
56 Accum Def Income Tax	(3,175,774,720)	(778,022,691)	(59,481,692)	(11,327)	-	394,628	(455,455)
57 Unamortized ITC	(562,961)	(26,013)	(2,062)	-	-	-	-
58 Customer Adv For Const	(333,031,816)	(88,409,248)	(6,210,511)	-	-	-	-
59 Customer Service Deposits	-	-	-	-	-	-	-
60 Misc Rate Base Deductions	(1,147,755,742)	(354,993,731)	(7,410,495)	(13,772)	-	-	(600,499)
61							
62 Total Rate Base Deductions	(21,348,651,670)	(6,163,229,344)	(330,234,719)	(5,211,504)	-	394,628	(4,855,063)
63							
64 Total Rate Base:	24,024,831,598	6,085,803,981	326,480,134	400,667	5,064	447,084	3,694,935
65							
66 Return on Rate Base		6.285%	-0.708%	-0.019%	-0.003%	-0.001%	-0.044%
67							
68 Return on Equity		7.161%	-1.415%	-0.039%	-0.005%	-0.001%	-0.088%
69							
70 TAX CALCULATION:							
71 Operating Revenue		336,062,484	(35,631,793)	(1,616,327)	-	-	(3,470,566)
72 Other Deductions		-					
73 Interest (AFUDC)		(2,826,222)	(141,538)	(199)	-	-	(59,922)
74 Interest		164,620,998	8,831,288	10,838	137	12,094	99,948
75 Schedule "M" Additions		329,762,524	18,175,473	191,737	-	6,941,529	1,010,624
76 Schedule "M" Deductions		401,633,646	22,851,093	6,028,503	-	-	741,269
77 Income Before Tax		102,396,587	(48,997,162)	(7,463,732)	(137)	6,929,435	(3,241,236)
78							
79 State Income Taxes		5,141,589	(2,224,471)	(338,853)	211,297	346,472	(162,062)
80 Taxable Income		97,254,998	(46,772,691)	(7,124,878)	(211,434)	6,582,963	(3,079,174)
81							

Pacificorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2027

		WA_6	WA_7	WA_8	WA_9	WA_10	WA_11	WA_12	WA_13
		Generation Resource Removal for Washington Sales	Removal of Other Balances for Washington Sales	Washington Wheeling Revenues	Chehalis Overhaul Expense Removal	Property Tax Expense Reduction	PowerTax Adjustment	Pro Forma Tax Adjustment	Prepaid Overhauls Removal
1	Operating Revenues:								
2	General Business Revenues	-	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-	-	-
5	Other Operating Revenues	52	17	7,163,378	-	-	-	-	-
6	Total Operating Revenues	52	17	7,163,378	-	-	-	-	-
7									
8	Operating Expenses:								
9	Steam Production	-	-	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-	-
11	Hydro Production	-	-	-	-	-	-	-	-
12	Solar Production	-	-	-	-	-	-	-	-
13	Wind Production	(1,415,922)	-	-	-	-	-	-	-
14	Other Renewable Production	-	-	-	-	-	-	-	-
15	Other Power Supply	(2,585,324)	(34)	-	(291,771)	-	-	-	-
16	Transmission	(68,021)	(745,671)	-	-	-	-	-	-
17	Distribution	-	-	-	-	-	-	-	-
18	Customer Accounting	-	-	-	-	-	-	-	-
19	Customer Service & Info	-	-	-	-	-	-	-	-
20	Sales	-	-	-	-	-	-	-	-
21	Administrative & General	2,793	(20,395)	-	-	-	-	-	-
22									
23	Total O&M Expenses	(4,066,474)	(766,099)	-	(291,771)	-	-	-	-
24									
25	Depreciation	(9,884,337)	(1,600,010)	-	-	-	-	-	-
26	Amortization	(130,004)	(34,800)	-	-	-	-	-	-
27	Taxes Other Than Income	1,891	(5,604,781)	-	-	(2,281,955)	-	-	-
28	Income Taxes - Federal	3,996,093	1,931,444	1,428,801	58,244	455,530	305,563	68,496	(15,047)
29	Income Taxes - State	1,001,527	484,071	358,096	14,598	114,168	76,582	17,167	(3,771)
30	Income Taxes - Def Net	24,668	9,663	-	-	-	(826,047)	287,377	-
31	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-
32	Misc Revenue & Expense	(15)	(5)	-	-	-	-	-	-
33									
34	Total Operating Expenses:	(9,056,651)	(5,580,517)	1,786,897	(218,929)	(1,712,257)	(443,902)	373,040	(18,818)
35									
36	Operating Rev For Return:	9,056,704	5,580,533	5,376,481	218,929	1,712,257	443,902	(373,040)	18,818
37									
38	Rate Base:								
39	Electric Plant In Service	(272,462,026)	(84,310,229)	-	-	-	-	-	-
40	Plant Held for Future Use	-	-	-	-	-	-	-	-
41	Misc Deferred Debits	(11,925,133)	517	-	-	-	-	-	2,788,831
42	Elec Plant Acq Adj	-	-	-	-	-	-	-	-
43	Pension	-	-	-	-	-	-	-	-
44	Prepayments	2,123	677	-	-	-	-	-	-
45	Fuel Stock	-	-	-	-	-	-	-	-
46	Material & Supplies	(38)	(1,337,325)	-	-	-	-	-	-
47	Working Capital	30,329	(119,366)	54,216	(6,643)	(51,952)	11,595	2,599	(571)
48	Weatherization Loans	-	-	-	-	-	-	-	-
49	Misc Rate Base	-	-	-	-	-	-	-	-
50									
51	Total Electric Plant:	(284,354,746)	(85,765,727)	54,216	(6,643)	(51,952)	11,595	2,599	2,788,260
52									
53	Rate Base Deductions:								
54	Accum Prov For Deprec	57,692,482	22,010,041	-	-	-	-	-	-
55	Accum Prov For Amort	2,799,549	292,126	-	-	-	-	-	-
56	Accum Def Income Tax	(986)	(252)	-	-	-	57,312,957	(11,343,039)	-
57	Unamortized ITC	-	-	-	-	-	-	-	-
58	Customer Adv For Const	-	-	-	-	-	-	-	-
59	Customer Service Deposits	-	-	-	-	-	-	-	-
60	Misc Rate Base Deductions	68,932	(456)	-	-	-	-	(1,352,301)	-
61									
62	Total Rate Base Deductions	60,559,977	22,301,459	-	-	-	57,312,957	(12,695,339)	-
63									
64	Total Rate Base:	(223,794,769)	(63,464,267)	54,216	(6,643)	(51,952)	57,324,552	(12,692,740)	2,788,260
65									
66	Return on Rate Base	0.345%	0.152%	0.088%	0.004%	0.028%	-0.050%	0.006%	-0.002%
67									
68	Return on Equity	0.691%	0.303%	0.175%	0.007%	0.056%	-0.099%	0.013%	-0.005%
69									
70	TAX CALCULATION:								
71	Operating Revenue	14,078,992	8,005,712	7,163,378	291,771	2,281,955	-	-	-
72	Other Deductions								
73	Interest (AFUDC)	1,822	1,711	-	-	-	-	-	-
74	Interest	(6,053,648)	(1,716,708)	1,467	(180)	(1,405)	1,550,629	(343,339)	75,422
75	Schedule "M" Additions	(101,475)	(41,255)	-	-	-	(11,412,392)	-	-
76	Schedule "M" Deductions	(1,204)	(1,973)	-	-	-	(14,494,664)	-	-
77	Income Before Tax	20,030,547	9,681,427	7,161,911	291,951	2,283,360	1,531,643	343,339	(75,422)
78									
79	State Income Taxes	1,001,527	484,071	358,096	14,598	114,168	76,582	17,167	(3,771)
80	Taxable Income	19,029,020	9,197,356	6,803,816	277,353	2,169,192	1,455,061	326,172	(71,651)
81									

Pacificorp
Oregon General Rate Case
Adjustment Summarv
Twelve Months Ending December 31, 2027

		WA_14	WA_15
		Washington Unamortized Pension Loss	Washington Accelerated Depreciation & Decommissioning
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	Hvdro Production	-	-
12	Solar Production	-	-
13	Wind Production	-	-
14	Other Renewable Production	-	-
15	Other Power Supplv	-	-
16	Transmission	-	-
17	Distribution	-	-
18	Customer Accounting	-	-
19	Customer Service & Info	-	-
20	Sales	-	-
21	Administrative & General	(186,953)	-
22			
23	Total O&M Expenses	(186,953)	-
24			
25	Depreciation	-	-
26	Amortization	-	-
27	Taxes Other Than Income	-	-
28	Income Taxes - Federal	37,320	110,480
29	Income Taxes - State	9,353	27,689
30	Income Taxes - Def Net	-	(58)
31	Investment Tax Credit Adj.	-	-
32	Misc Revenue & Expense	-	-
33			
34	Total Operating Expenses:	(140,279)	138,111
35			
36	Operating Rev For Return:	140,279	(138,111)
37			
38	Rate Base:		
39	Electric Plant In Service	-	-
40	Plant Held for Future Use	-	-
41	Misc Deferred Debits	-	-
42	Elec Plant Acq Adj	-	-
43	Pension	-	-
44	Prepavments	-	-
45	Fuel Stock	-	-
46	Material & Supplies	-	-
47	Working Capital	(4,256)	(6,762,293)
48	Weatherization Loans	-	-
49	Misc Rate Base	-	-
50			
51	Total Electric Plant:	(4,256)	(6,762,293)
52			
53	Rate Base Deductions:		
54	Accum Prov For Deprec	-	(20,601,734)
55	Accum Prov For Amort	-	-
56	Accum Def Income Tax	-	6,878,729
57	Unamortized ITC	-	-
58	Customer Adv For Const	-	-
59	Customer Service Deposits	-	-
60	Misc Rate Base Deductions	-	-
61			
62	Total Rate Base Deductions	-	(13,723,006)
63			
64	Total Rate Base:	(4,256)	(20,485,298)
65			
66	Return on Rate Base	0.002%	0.018%
67			
68	Return on Equitv	0.005%	0.036%
69			
70	TAX CALCULATION:		
71	Operating Revenue	186,953	-
72	Other Deductions		
73	Interest (AFUDC)	-	577
74	Interest	(115)	(554,127)
75	Schedule "M" Additions	-	(604)
76	Schedule "M" Deductions	-	(836)
77	Income Before Tax	187,068	553,784
78			
79	State Income Taxes	9,353	27,689
80	Taxable Income	177,715	526,094
81			

Tab 2 - Report

PacifiCorp
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	OREGON
PERIOD:	TWELVE MONTHS ENDING DECEMBER 31, 2027
FILE:	OR JAM Dec 2027 GRC_Post-sale
PREPARED BY:	Revenue Requirement Department
DATE:	4/9/2026
TIME:	11:50:36 AM
TYPE OF RATE BASE:	13-Month Average
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	5.00%
TAX GROSS UP FACTOR	1.332
FEDERAL/STATE COMBINED RATE	24.950%

CAPITAL STRUCTURE INFORMATION

	CAPITAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
DEBT	50.00%	5.41%	2.71%
PREFERRED	0.00%	6.75%	0.00%
COMMON	50.00%	9.70%	4.85%
	100.00%		7.56%

OTHER INFORMATION

For information and support regarding capital structure and cost of debt, see testimony of company witness M. Ryan Weems
For information and support regarding return on common equity, see testimony of company witness Ann E. Bulkley.

2020 PROTOCOL

RESULTS OF OPERATIONS SUMMARY

	Description of Account Summary:	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
1	Operating Revenues					
2	General Business Revenues	2.2	6,662,182,389	1,793,305,491	6,191,979,573	1,793,305,491
3	Interdepartmental	2.2	0	0	0	0
4	Special Sales	2.2	70,898,832	54,006,161	70,898,832	54,006,161
5	Other Operating Revenues	2.3	285,994,780	74,085,068	308,613,557	85,908,037
6	Total Operating Revenues	2.3	7,019,076,002	1,921,396,720	6,571,491,962	1,933,219,689
7						
8	Operating Expenses:					
9	Steam Production	2.5	498,367,279	264,348,177	498,367,279	271,448,356
10	Nuclear Production	2.5	0	0	0	0
11	Hydro Production	2.6	48,199,621	13,378,082	48,199,621	14,438,443
12	Solar Production	2.6	232,196	232,196	232,196	232,196
13	Wind Production	2.6	37,051,549	10,283,870	32,324,797	9,683,058
14	Other Renewable Production	2.6	3,122,787	1,997,903	3,122,787	2,032,157
15	Other Power Supply	2.7, .8	833,424,602	449,391,626	823,819,929	449,340,665
16	Transmission	2.9	155,583,147	91,307,111	152,866,812	92,450,708
17	Distribution	2.10	349,264,972	125,776,662	328,929,699	126,356,176
18	Customer Accounting	2.11	100,540,869	32,131,875	91,528,290	33,351,555
19	Customer Service & Infor	2.12	248,676,556	5,324,067	244,832,740	5,496,218
20	Sales	2.12	0	0	0	0
21	Administrative & General	2.13	314,131,993	140,886,076	308,670,538	145,032,355
22						
23	Total O & M Expenses	2.13	2,588,595,571	1,135,057,645	2,532,894,688	1,149,861,887
24						
25	Depreciation	2.14	1,235,870,409	337,794,580	1,177,371,425	346,611,678
26	Amortization	2.15	22,421,726	(295,207)	21,770,064	49,265
27	Taxes Other Than Income	2.15	271,441,309	112,881,934	245,143,352	109,475,699
28	Income Taxes - Federal	2.18	411,715,574	(60,628,691)	356,036,165	(62,880,290)
29	Income Taxes - State	2.18	121,278,480	5,141,589	119,274,201	5,073,452
30	Income Taxes - Def Net	2.16	(96,399,478)	9,027,360	(89,384,227)	9,465,875
31	Investment Tax Credit Adj.	2.15	(514)	0	(514)	0
32	Misc Revenue & Expense	2.3	(1,011,940)	(104,716)	(1,011,940)	(131,398)
33						
34	Total Operating Expenses	2.18	4,553,911,138	1,538,874,495	4,362,093,214	1,557,526,166
35						
36	Operating Revenue for Return		2,465,164,863	382,522,225	2,209,398,748	375,693,523
37						
38	Rate Base:					
39	Electric Plant in Service	2.26	42,016,634,369	11,726,376,909	40,036,913,335	12,017,823,879
40	Plant Held for Future Use	2.26	0	0	0	0
41	Misc Deferred Debits	2.28	1,674,027,413	93,002,614	1,652,784,057	90,949,364
42	Elec Plant Acq Adj	2.26,.27	11,124,844	684,215	11,124,844	738,446
43	Pensions	2.27	0	0	0	0
44	Prepayments	2.28	174,702,384	51,058,541	174,702,384	54,456,191
45	Fuel Stock	2.27	334,920,385	89,834,980	334,920,385	96,294,524
46	Material & Supplies	2.28	671,506,101	239,908,978	635,562,549	241,997,615
47	Working Capital	2.28	154,423,410	62,523,353	129,649,855	57,975,167
48	Weatherization Loans	2.27	350,500,629	0	350,497,317	0
49	Miscellaneous Rate Base	2.29	(14,356,267)	(14,356,267)	(14,356,267)	(14,356,267)
50						
51	Total Electric Plant		45,373,483,268	12,249,033,325	43,311,798,460	12,545,878,921
52						
53	Rate Base Deductions:					
54	Accum Prov For Depr	2.32	(16,533,503,057)	(4,896,570,165)	(15,946,082,068)	(5,100,447,662)
55	Accum Prov For Amort	2.33	(158,023,373)	(45,207,495)	(145,240,659)	(45,253,009)
56	Accum Def Income Taxes	2.30	(3,175,774,720)	(778,022,691)	(3,001,105,620)	(784,729,128)
57	Unamortized ITC	2.30	(562,961)	(26,013)	(562,961)	(28,075)
58	Customer Adv for Const	2.29	(333,031,816)	(88,409,248)	(332,287,853)	(94,619,759)
59	Customer Service Deposits	2.29	0	0	0	0
60	Misc. Rate Base Deductions	2.29	(1,147,755,742)	(354,993,731)	(1,064,855,582)	(364,302,321)
61						
62	Total Rate Base Deductions		(21,348,651,670)	(6,163,229,344)	(20,490,134,743)	(6,389,379,954)
63						
64	Total Rate Base		24,024,831,598	6,085,803,981	22,821,663,717	6,156,498,967
65						
66	Return on Rate Base		4.905%	6.285%	9.681%	6.102%
67						
68	Return on Equity		4.420%	7.161%	13.952%	6.795%
69	Net Power Costs		613,171,486	613,171,486	613,171,486	613,171,486
70	100 Basis Points in Equity:		115,324,819	30,515,440	114,108,319	30,782,495
71	Revenue Requirement Impact		159,287,551	40,349,619	152,043,063	41,015,982
72	Rate Base Decrease		(1,116,301,753)	(448,442,892)	(1,120,780,613)	(466,232,667)

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
73	Sales to Ultimate Customers							
74	440	Residential Sales						
75			S		2,586,684,710	819,709,408	2,359,065,257	819,709,408
76								
77				B1	2,586,684,710	819,709,408	2,359,065,257	819,709,408
78								
79	442	Commercial & Industrial Sales						
80			S		4,060,400,129	969,757,928	3,818,548,756	969,757,928
81			SE		-	-	-	-
82			SG		-	-	-	-
83								
84								
85				B1	4,060,400,129	969,757,928	3,818,548,756	969,757,928
86								
87	444	Public Street & Highway Lighting						
88			S		15,097,550	3,838,155	14,365,560	3,838,155
89			SO		-	-	-	-
90				B1	15,097,550	3,838,155	14,365,560	3,838,155
91								
92	445	Other Sales to Public Authority						
93			S		-	-	-	-
94								
95				B1	-	-	-	-
96								
97	448	Interdepartmental						
98			S		-	-	-	-
99			SO		-	-	-	-
100				B1	-	-	-	-
101								
102	**Total Sales to Ultimate Customers**			**B1**	**6,662,182,389**	**1,793,305,491**	**6,191,979,573**	**1,793,305,491**
103								
104								
105								
106	447	Sales for Resale-Non NPC						
107			S		16,892,672	-	16,892,672	-
108				B1	16,892,672	-	16,892,672	-
109								
110	447NPC	Sales for Resale-NPC						
111			S		54,006,161	54,006,161	54,006,161	54,006,161
112			SE		-	-	-	-
113			SG		(0)	(0)	(0)	(0)
114				B1	54,006,161	54,006,161	54,006,161	54,006,161
115								
116		Total Sales for Resale		B1	70,898,832	54,006,161	70,898,832	54,006,161
117								
118	449	Provision for Rate Refund						
119			S		-	-	-	-
120			SG		-	-	-	-
121								
122								
123				B1	-	-	-	-
124								
125	**Total Sales from Electricity**			**B1**	**6,733,081,221**	**1,847,311,652**	**6,262,878,405**	**1,847,311,652**
126	450	Forfeited Discounts & Interest						
127			S		14,121,026	6,625,546	13,976,232	6,625,546
128			SO		-	-	-	-
129				B1	14,121,026	6,625,546	13,976,232	6,625,546
130								
131	451	Misc Electric Revenue						
132			S		9,187,867	551,000	8,860,782	551,000
133			SG		-	-	-	-
134			SO		68,001	18,978	68,001	20,412
135				B1	9,255,868	569,979	8,928,783	571,412
136								
137	453	Water Sales						
138			SG		5,895	1,636	5,895	1,766
139				B1	5,895	1,636	5,895	1,766
140								
141	454	Rent of Electric Property						
142			S		14,124,583	7,261,847	13,301,850	7,261,847
143			SG		2,219,479	616,029	2,219,479	664,856
144			SG		-	-	-	-
145			SO		3,732,305	1,041,645	3,732,305	1,120,321
146				B1	20,076,367	8,919,522	19,253,634	9,047,024

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
147								
148								
149								
150	456	Other Electric Revenue						
151			S		33,213,017	125,601	33,213,017	125,601
152			CN		-	-	-	-
153			SE		27,437,201	7,359,422	27,437,201	7,888,598
154			SO		14,636	4,085	14,636	4,393
155			SG		181,870,771	50,479,278	205,784,160	61,643,697
156								
157								
158				B1	242,535,625	57,968,385	266,449,014	69,662,289
159								
160	**Total Other Electric Revenues**			**B1**	**285,994,780**	**74,085,068**	**308,613,557**	**85,908,037**
161								
162	**Total Electric Operating Revenues**			**B1**	**7,019,076,002**	**1,921,396,720**	**6,571,491,962**	**1,933,219,689**
163								
164	Summary of Revenues by Factor							
165		S			6,803,727,713	1,861,875,647	6,332,230,285	1,861,875,647
166		CN			-	-	-	-
167		SE			27,437,201	7,359,422	27,437,201	7,888,598
168		SO			3,814,942	1,064,708	3,814,942	1,145,126
169		SG			184,096,145	51,096,943	208,009,534	62,310,319
170		DGP			-	-	-	-
171								
172	Total Electric Operating Revenues				7,019,076,002	1,921,396,720	6,571,491,962	1,933,219,689
173	Miscellaneous Revenues							
174	41160	Gain on Sale of Utility Plant - CR						
175			S		-	-	-	-
176			SG		-	-	-	-
177			SO		-	-	-	-
178			SG		-	-	-	-
179			SG		-	-	-	-
180				B1	-	-	-	-
181								
182	41170	Loss on Sale of Utility Plant						
183			S		-	-	-	-
184			SG		-	-	-	-
185				B1	-	-	-	-
186								
187	4118	Gain from Emission Allowances						
188			S		-	-	-	-
189			SE		(41)	(11)	(41)	(12)
190				B1	(41)	(11)	(41)	(12)
191								
192	41181	Gain from Disposition of NOX Credits						
193			SE		-	-	-	-
194				B1	-	-	-	-
195								
196	4194	Impact Housing Interest Income						
197			SG		-	-	-	-
198				B1	-	-	-	-
199								
200	421	(Gain) / Loss on Sale of Utility Plant						
201			S		246,124	246,124	246,124	246,124
202			SG		-	-	-	-
203			SG-P		21,315	5,916	21,315	6,385
204			CN		-	-	-	-
205			SO		(1,081,410)	(301,810)	(1,081,410)	(324,605)
206			SG		(197,928)	(54,936)	(197,928)	(59,290)
207				B1	(1,011,899)	(104,705)	(1,011,899)	(131,386)
208								
209	**Total Miscellaneous Revenues**			**B1**	**(1,011,940)**	**(104,716)**	**(1,011,940)**	**(131,398)**
210	Miscellaneous Expenses							
211	4311	Interest on Customer Deposits						
212			S		-	-	-	-
213					-	-	-	-
214	**Total Miscellaneous Expenses**			B1	**-**	**-**	**-**	**-**
215								
216	**Net Misc Revenue and Expense**			**B1**	**(1,011,940)**	**(104,716)**	**(1,011,940)**	**(131,398)**
217								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
218	500	Operation Supervision & Engineering						
219			SG		-	-	-	-
220			SG		-	-	-	-
221			SG		17,803,495	4,941,462	17,803,495	5,333,128
222				B2	17,803,495	4,941,462	17,803,495	5,333,128
223								
224	501	Fuel Related-Non NPC						
225			S		-	-	-	-
226			SE		3,416,237	916,330	3,416,237	982,218
227			SE		-	-	-	-
228			SE		-	-	-	-
229			SE		-	-	-	-
230				B2	3,416,237	916,330	3,416,237	982,218
231								
232	501NPC	Fuel Related-NPC						
233			S		174,552,460	174,552,460	174,552,460	174,552,460
234			SE		-	-	-	-
235			SE		-	-	-	-
236			SE		-	-	-	-
237			SE		-	-	-	-
238				B2	174,552,460	174,552,460	174,552,460	174,552,460
239								
240		Total Fuel Related		B2	177,968,697	175,468,790	177,968,697	175,534,678
241								
242	502	Steam Expenses						
243			SG		-	-	-	-
244			SG		-	-	-	-
245			SG		72,568,586	20,141,828	72,568,586	21,738,291
246				B2	72,568,586	20,141,828	72,568,586	21,738,291
247								
248	503	Steam From Other Sources-Non-NPC						
249			SE		702	188	702	202
250				B2	702	188	702	202
251								
252	503NPC	Steam From Other Sources-NPC						
253			S		-	-	-	-
254			SE		-	-	-	-
255				B2	-	-	-	-
256								
257	505	Electric Expenses						
258			SG		-	-	-	-
259			SG		-	-	-	-
260			SG		1,204,129	334,213	1,204,129	360,703
261				B2	1,204,129	334,213	1,204,129	360,703
262								
263	506	Misc. Steam Expense				0.00%		
264			SG		-	-	-	-
265			SG		49,003,503	13,601,204	49,003,503	14,679,250
266			SE		5,261,096	1,411,173	5,261,096	1,512,642
267				B2	54,264,599	15,012,376	54,264,599	16,191,892
268								
269	507	Rents						
270			SG		-	-	-	-
271			SG		565,821	157,047	565,821	169,495
272			SG		-	-	-	-
273				B2	565,821	157,047	565,821	169,495
274								
275	509NPC	Allowances-NPC						
276			S		-	-	-	-
277			SG		-	-	-	-
278				B2	-	-	-	-
279								
280	510	Maint Supervision & Engineering						
281			SG		-	-	-	-
282			SG		-	-	-	-
283			SG		13,234,928	3,673,430	13,234,928	3,964,590
284				B2	13,234,928	3,673,430	13,234,928	3,964,590
285								
286								
287								
288	511	Maintenance of Structures						
289			SG		-	-	-	-
290			SG		-	-	-	-
291			SG		23,292,800	6,465,050	23,292,800	6,977,477
292				B2	23,292,800	6,465,050	23,292,800	6,977,477
293								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
294	512	Maintenance of Boiler Plant						
295			SG		-	-	-	-
296			SG		-	-	-	-
297			SG		80,189,393	22,257,027	80,189,393	24,021,142
298				B2	80,189,393	22,257,027	80,189,393	24,021,142
299								
300	513	Maintenance of Electric Plant						
301			SG		-	-	-	-
302			SG		-	-	-	-
303			SG		41,368,563	11,482,082	41,368,563	12,392,164
304				B2	41,368,563	11,482,082	41,368,563	12,392,164
305								
306	514	Maintenance of Misc. Steam Plant						
307			SG		-	-	-	-
308			SG		-	-	-	-
309			SG		15,905,566	4,414,681	15,905,566	4,764,594
310				B2	15,905,566	4,414,681	15,905,566	4,764,594
311								
312	**Total Steam Power Generation**			**B2**	**498,367,279**	**264,348,177**	**498,367,279**	**271,448,356**
313	517	Operation Super & Engineering						
314			SG		-	-	-	-
315				B2	-	-	-	-
316								
317	518	Nuclear Fuel Expense						
318			SE		-	-	-	-
319								
320				B2	-	-	-	-
321								
322	519	Coolants and Water						
323			SG		-	-	-	-
324				B2	-	-	-	-
325								
326	520	Steam Expenses						
327			SG		-	-	-	-
328				B2	-	-	-	-
329								
330								
331								
332	523	Electric Expenses						
333			SG		-	-	-	-
334				B2	-	-	-	-
335								
336	524	Misc. Nuclear Expenses						
337			SG		-	-	-	-
338				B2	-	-	-	-
339								
340	528	Maintenance Super & Engineering						
341			SG		-	-	-	-
342				B2	-	-	-	-
343								
344	529	Maintenance of Structures						
345			SG		-	-	-	-
346				B2	-	-	-	-
347								
348	530	Maintenance of Reactor Plant						
349			SG		-	-	-	-
350				B2	-	-	-	-
351								
352	531	Maintenance of Electric Plant						
353			SG		-	-	-	-
354				B2	-	-	-	-
355								
356	532	Maintenance of Misc Nuclear						
357			SG		-	-	-	-
358				B2	-	-	-	-
359								
360	**Total Nuclear Power Generation**			**B2**	**-**	**-**	**-**	**-**
361								
362	535	Operation Super & Engineering						
363			SG		9,927,399	2,755,407	9,927,399	2,973,803
364			SG		3,927,509	1,090,103	3,927,509	1,176,505
365			SG		(1,611,655)	(447,324)	(1,611,655)	(482,780)
366			SG		-	-	-	-
367			SG		-	-	-	-
368								
369				B2	12,243,253	3,398,185	12,243,253	3,667,529
370								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
371	536	Water For Power						
372			SG		(137,665)	(38,210)	(137,665)	(41,238)
373			SG		-	-	-	-
374			SG		-	-	-	-
375								
376				B2	(137,665)	(38,210)	(137,665)	(41,238)
377								
378	537	Hydraulic Expenses						
379			SG		5,604,357	1,555,522	5,604,357	1,678,814
380			SG		-	-	-	-
381			SG		-	-	-	-
382			SG		394,511	109,499	394,511	118,178
383				B2	5,998,868	1,665,020	5,998,868	1,796,992
384								
385	538	Electric Expenses						
386			DGP		-	-	-	-
387			SG		-	-	-	-
388			SG		-	-	-	-
389								
390				B2	-	-	-	-
391								
392	539	Misc. Hydro Expenses						
393			SG		-	-	-	-
394			SG		-	-	-	-
395			SG		-	-	-	-
396			SG		9,471,734	2,628,934	9,471,734	2,837,306
397			SG		10,055,396	2,790,933	10,055,396	3,012,145
398				B2	19,527,130	5,419,867	19,527,130	5,849,452
399								
400	540	Rents (Hydro Generation)						
401			SG		-	-	-	-
402			SG-P		1,621,020	449,923	1,621,020	485,585
403			SG-U		115,802	32,142	115,802	34,689
404								
405				B2	1,736,822	482,065	1,736,822	520,274
406								
407	541	Maint Supervision & Engineering						
408			SG		-	-	-	-
409			SG-P		397	110	397	119
410			SG-U		-	-	-	-
411								
412				B2	397	110	397	119
413								
414	542	Maintenance of Structures						
415			SG		51,255	14,226	51,255	15,354
416			SG		-	-	-	-
417			SG		-	-	-	-
418			SG		499,993	138,776	499,993	149,776
419				B2	551,248	153,002	551,248	165,129
420								
421								
422								
423								
424	543	Maintenance of Dams & Waterways						
425			SG		461,403	128,065	461,403	138,216
426			SG		-	-	-	-
427			SG		-	-	-	-
428			SG		666,319	184,941	666,319	199,599
429				B2	1,127,723	313,006	1,127,723	337,815
430								
431	544	Maintenance of Electric Plant						
432			SG		919,156	255,117	919,156	275,338
433			SG		-	-	-	-
434			SG		-	-	-	-
435			SG		716,051	198,744	716,051	214,497
436				B2	1,635,208	453,861	1,635,208	489,835
437								
438	545	Maintenance of Misc. Hydro Plant						
439			SG		4,567,312	1,267,684	4,567,312	1,368,162
440			SG		949,326	263,491	949,326	284,375
441			SG		-	-	-	-
442			SG		-	-	-	-
443			SG		-	-	-	-
444								
445				B2	5,516,638	1,531,175	5,516,638	1,652,537
446								
447	**Total Hydraulic Power Generation**			**B2**	**48,199,621**	**13,378,082**	**48,199,621**	**14,438,443**
448								
449								
450								
451								
452	558XP	Solar Power Expenses						

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
453			S		232,196	232,196	232,196	232,196
454			SG		-	-	-	-
455				B2	232,196	232,196	232,196	232,196
456								
457	**Total Solar Power Generation**			**B2**	**232,196**	**232,196**	**232,196**	**232,196**
458								
459								
460								
461								
462	558WP	Wind Power Expenses						
463			S		-	-	-	-
464			SG		37,051,549	10,283,870	32,324,797	9,683,058
465				B2	37,051,549	10,283,870	32,324,797	9,683,058
466								
467	**Total Wind Power Generation**			**B2**	**37,051,549**	**10,283,870**	**32,324,797**	**9,683,058**
468								
469								
470								
471								
472	559NPC	Other Renewable Fuel						
473			S		1,565,734	1,565,734	1,565,734	1,565,734
474			SE		-	-	-	-
475				B2	1,565,734	1,565,734	1,565,734	1,565,734
476								
477	559	Other Renewable Expenses						
478			S		-	-	-	-
479			SG		1,557,054	432,169	1,557,054	466,423
480				B2	1,557,054	432,169	1,557,054	466,423
481								
482	**Total Other Renewable Generation**			**B2**	**3,122,787**	**1,997,903**	**3,122,787**	**2,032,157**
483								
484	546	Operation Super & Engineering						
485			SG		-	-	-	-
486			SG		-	-	-	-
487			SG		481,578	133,665	260,951	78,169
488				B2	481,578	133,665	260,951	78,169
489								
490	547	Fuel-Non-NPC						
491			SE		-	-	-	-
492			SE		-	-	-	-
493				B2	-	-	-	-
494								
495	547NPC	Fuel-NPC						
496			S		140,545,976	140,545,976	140,545,976	140,545,976
497			SE		-	-	-	-
498				B2	140,545,976	140,545,976	140,545,976	140,545,976

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
499								
500	548	Generation Expense						
501			SG		-	-	-	-
502			SG		-	-	-	-
503			SG		31,023,641	8,610,790	28,253,244	8,463,403
504				B2	31,023,641	8,610,790	28,253,244	8,463,403
505								
506	549	Miscellaneous Other						
507			S		21,060	21,060	21,060	21,060
508			SG		-	-	-	-
509			SG		-	-	-	-
510			SG		8,237,957	2,286,492	6,598,975	1,976,757
511			SG		-	-	-	-
512				B2	8,259,017	2,307,552	6,620,034	1,997,816
513								
514								
515								
516								
517	550	Rents						
518			S		193,512	193,512	193,512	193,512
519			SG		3,758,773	1,043,269	2,717,803	814,132
520			SG		-	-	-	-
521			SG		-	-	-	-
522				B2	3,952,286	1,236,782	2,911,316	1,007,644
523								
524	551	Maint Supervision & Engineering						
525			SG		-	-	-	-
526				B2	-	-	-	-
527								
528	552	Maintenance of Structures						
529			SG		-	-	-	-
530			SG		-	-	-	-
531			SG		3,040,690	843,961	2,953,761	884,814
532				B2	3,040,690	843,961	2,953,761	884,814
533								
534	553	Maint of Generation & Electric Plant						
535			SG		-	-	-	-
536			SG		-	-	-	-
537			SG		-	-	-	-
538			SG		20,737,051	5,755,688	17,143,216	5,135,338
539				B2	20,737,051	5,755,688	17,143,216	5,135,338
540								
541	554	Maintenance of Misc. Other						
542			SG		-	-	-	-
543			SG		-	-	-	-
544			SG		-	-	-	-
545			SG		6,185,154	1,716,725	6,100,601	1,827,466
546				B2	6,185,154	1,716,725	6,100,601	1,827,466
547								
548	**Total Other Power Generation**			**B2**	**214,225,393**	**161,151,138**	**204,789,099**	**159,940,628**
549								
550								
551	555	Purchased Power-Non NPC						
552			S		285,964,068	-	285,964,068	-
553					285,964,068	-	285,964,068	-
554								
555	555NPC	Purchased Power-NPC						
556			S		283,900,565	283,900,565	283,900,565	283,900,565
557			SE		(0)	(0)	(0)	(0)
558		Seasonal Contracts	SG		-	-	-	-
559			DGP		-	-	-	-
560					283,900,565	283,900,565	283,900,565	283,900,565
561								
562		Total Purchased Power		B2	569,864,633	283,900,565	569,864,633	283,900,565
563								
564	556	System Control & Load Dispatch						
565			SG		3,473,284	964,030	3,473,284	1,040,440
566								
567				B2	3,473,284	964,030	3,473,284	1,040,440
568								
569								
570								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
571	557	Other Expenses						
572			S		4,496,880	73,841	4,496,880	73,841
573			SG		51,520,013	14,299,676	51,351,634	15,382,644
574			SGCT		-	-	-	-
575			SE		8,857	2,376	8,857	2,546
576			SG		-	-	-	-
577			TROJP		-	-	-	-
578								
579				B2	56,025,750	14,375,893	55,857,371	15,459,032
580								
581	Embedded Cost Differentials							
582	Company Owned Hydro		DGP		-	-	-	-
583	Company Owned Hydro		SG		-	-	-	-
584	Mid-C Contract		MC		-	-	-	-
585	Mid-C Contract		SG		-	-	-	-
586	Existing QF Contracts		S		-	-	-	-
587	Existing QF Contracts		SG		-	-	-	-
588								
589					-	-	-	-
590								
591								
592								
593								
594	2020 Protocol Adjustment							
595	Baseline ECD		S		(10,164,458)	(11,000,000)	(10,164,458)	(11,000,000)
596			S		-	-	-	-
597	2020 Protocol Adjustment				(10,164,458)	(11,000,000)	(10,164,458)	(11,000,000)
598								
599	**Total Other Power Supply**			**B2**	**619,199,209**	**288,240,488**	**619,030,830**	**289,400,037**
600								
601	**Total Production Expense**			**B2**	**1,420,398,034**	**739,631,854**	**1,406,066,610**	**747,174,876**
602								
603								
604	Summary of Production Expense by Factor							
605		S			881,307,994	590,085,345	881,307,994	590,085,345
606		SG			528,665,931	146,734,267	514,334,506	154,071,529
607		SE			8,686,891	2,330,066	8,686,891	2,497,609
608		SNPPH			-	-	-	-
609		TROJP			-	-	-	-
610		SGCT			-	-	-	-
611		DGP			-	-	-	-
612		DEU			-	-	-	-
613		DEP			-	-	-	-
614		SNPPS			-	-	-	-
615		SNPPO			-	-	-	-
616		DGU			-	-	-	-
617		MC			-	-	-	-
618		SSGCT			-	-	-	-
619		SSECT			-	-	-	-
620		SSGC			-	-	-	-
621		SSGCH			-	-	-	-
622		SSECH			-	-	-	-
623	Total Production Expense by Factor				1,418,660,816	739,149,679	1,404,329,391	746,654,483
624	560	Operation Supervision & Engineering						
625			SG		-	-	-	-
626			SG		14,741,288	4,091,529	14,741,288	4,415,828
627								
628				B2	14,741,288	4,091,529	14,741,288	4,415,828
629								
630	561	Load Dispatching						
631			SG		-	-	-	-
632			SG		22,694,126	6,298,885	22,694,126	6,798,142
633								
634				B2	22,694,126	6,298,885	22,694,126	6,798,142
635	562	Station Expense						
636			SG		-	-	-	-
637			SG		3,784,537	1,050,420	3,693,526	1,106,415
638								
639				B2	3,784,537	1,050,420	3,693,526	1,106,415
640								
641	563	Overhead Line Expense						
642			SG		-	-	-	-
643			SG		1,811,060	502,670	1,695,768	507,976
644								
645				B2	1,811,060	502,670	1,695,768	507,976
646								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
647	564	Underground Line Expense						
648			SG		-	-	-	-
649								
650				B2	-	-	-	-
651								
652	565	Transmission of Electricity by Others						
653			SG		-	-	-	-
654			SE		-	-	-	-
655					-	-	-	-
656								
657	565NPC	Transmission of Electricity by Others-NPC						
658			S		66,612,911	66,612,911	66,612,911	66,612,911
659			SG		-	-	-	-
660			SE		-	-	-	-
661					66,612,911	66,612,911	66,612,911	66,612,911
662								
663		Total Trans of Electricity by Others		B2	66,612,911	66,612,911	66,612,911	66,612,911
664								
665	566	Misc. Transmission Expense						
666			SG		-	-	-	-
667			SG		4,440,328	1,232,439	4,397,650	1,317,338
668								
669				B2	4,440,328	1,232,439	4,397,650	1,317,338
670								
671	567	Rents - Transmission						
672			SG		-	-	-	-
673			SG		2,487,885	690,527	2,406,182	720,784
674								
675				B2	2,487,885	690,527	2,406,182	720,784
676								
677	568	Maint Supervision & Engineering						
678			SG		-	-	-	-
679			SG		1,838,820	510,375	1,838,820	550,828
680								
681				B2	1,838,820	510,375	1,838,820	550,828
682								
683	569	Maintenance of Structures						
684			SG		-	-	-	-
685			SG		7,814,849	2,169,056	7,764,761	2,325,974
686								
687				B2	7,814,849	2,169,056	7,764,761	2,325,974
688								
689	570	Maintenance of Station Equipment						
690			SG		-	-	-	-
691			SG		14,609,218	4,054,873	13,912,307	4,167,503
692								
693				B2	14,609,218	4,054,873	13,912,307	4,167,503
694								
695	571	Maintenance of Overhead Lines						
696			SG		-	-	-	-
697			SG		14,295,018	3,967,664	12,775,545	3,826,980
698								
699				B2	14,295,018	3,967,664	12,775,545	3,826,980
700								
701	572	Maintenance of Underground Lines						
702			SG		-	-	-	-
703			SG		123,491	34,276	4,314	1,292
704								
705				B2	123,491	34,276	4,314	1,292
706								
707	573	Maint of Misc. Transmission Plant						
708			SG		-	-	-	-
709			SG		329,615	91,487	329,615	98,738
710								
711				B2	329,615	91,487	329,615	98,738
712								
713	**Total Transmission Expense**			**B2**	**155,583,147**	**91,307,111**	**152,866,812**	**92,450,708**
714								
715	Summary of Transmission Expense by Factor							
716		SE			-	-	-	-
717		SG			88,970,236	24,694,200	86,253,901	25,837,797
718		SNPT			-	-	-	-
719	Total Transmission Expense by Factor				88,970,236	24,694,200	86,253,901	25,837,797
720	580	Operation Supervision & Engineering						
721			S		8,941,384	5,491,556	8,595,697	5,491,556
722			SNPD		7,786,584	1,991,660	7,786,584	2,096,881
723				B2	16,727,968	7,483,215	16,382,281	7,588,436
724								
725	581	Load Dispatching						
726			S		-	-	-	-
727			SNPD		18,223,846	4,661,312	18,223,846	4,907,573
728				B2	18,223,846	4,661,312	18,223,846	4,907,573

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
729								
730	582	Station Expense						
731			S		6,299,785	1,316,622	5,964,247	1,316,622
732			SNPD		496	127	496	134
733				B2	6,300,281	1,316,749	5,964,743	1,316,756
734								
735	583	Overhead Line Expenses						
736			S		13,465,834	1,545,622	13,026,595	1,545,622
737			SNPD		-	-	-	-
738				B2	13,465,834	1,545,622	13,026,595	1,545,622
739								
740	584	Underground Line Expense						
741			S		-	-	-	-
742			SNPD		-	-	-	-
743				B2	-	-	-	-
744								
745	585	Street Lighting & Signal Systems						
746			S		-	-	-	-
747			SNPD		322,655	82,529	322,655	86,889
748				B2	322,655	82,529	322,655	86,889
749								
750	586	Meter Expenses						
751			S		4,344,665	1,594,087	3,999,345	1,594,087
752			SNPD		10,938	2,798	10,938	2,945
753				B2	4,355,603	1,596,884	4,010,282	1,597,032
754								
755	587	Customer Installation Expenses						
756			S		22,111,871	7,502,020	20,416,897	7,502,020
757			SNPD		-	-	-	-
758				B2	22,111,871	7,502,020	20,416,897	7,502,020
759								
760	588	Misc. Distribution Expenses						
761			S		110,566	(816,416)	215,933	(816,416)
762			SNPD		(1,419,284)	(363,026)	(1,419,284)	(382,205)
763				B2	(1,308,718)	(1,179,442)	(1,203,352)	(1,198,621)
764								
765	589	Rents						
766			S		3,478,670	1,929,572	3,297,645	1,929,572
767			SNPD		598,109	152,985	598,109	161,067
768				B2	4,076,778	2,082,557	3,895,754	2,090,639
769								
770	590	Maint Supervision & Engineering						
771			S		5,194,702	1,529,238	4,947,248	1,529,238
772			SNPD		4,341,998	1,110,600	4,341,998	1,169,274
773				B2	9,536,700	2,639,838	9,289,246	2,698,512
774								
775	591	Maintenance of Structures						
776			S		3,589,410	1,466,942	3,366,197	1,466,942
777			SNPD		137,107	35,069	137,107	36,922
778				B2	3,726,518	1,502,011	3,503,304	1,503,864
779								
780	592	Maintenance of Station Equipment						
781			S		13,705,368	5,335,515	12,255,492	5,335,515
782			SNPD		3,451,746	882,891	3,451,746	929,535
783				B2	17,157,114	6,218,406	15,707,239	6,265,050
784	593	Maintenance of Overhead Lines						
785			S		174,475,861	74,287,728	162,885,017	74,287,728
786			SNPD		3,910,009	1,000,106	3,910,009	1,052,942
787				B2	178,385,869	75,287,834	166,795,025	75,340,670
788								
789	594	Maintenance of Underground Lines						
790			S		44,227,046	11,445,031	41,507,396	11,445,031
791			SNPD		8,115	2,076	8,115	2,185
792				B2	44,235,161	11,447,107	41,515,511	11,447,217
793								
794	595	Maintenance of Line Transformers						
795			S		-	-	-	-
796			SNPD		1,102,327	281,954	1,102,327	296,850
797				B2	1,102,327	281,954	1,102,327	296,850
798								
799	596	Maint of Street Lighting & Signal Sys.						
800			S		2,105,754	867,844	2,046,147	867,844
801			SNPD		-	-	-	-
802				B2	2,105,754	867,844	2,046,147	867,844
803								
804	597	Maintenance of Meters						
805			S		775,339	228,077	557,399	228,077
806			SNPD		(158,709)	(40,595)	(158,709)	(42,739)
807				B2	616,630	187,482	398,690	185,337
808								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
809	598	Maint of Misc. Distribution Plant						
810			S		3,553,445	1,083,990	2,963,171	1,083,990
811			SNPD		4,569,337	1,168,749	4,569,337	1,230,495
812				B2	8,122,781	2,252,739	7,532,508	2,314,485
813								
814	**Total Distribution Expense**			**B2**	**349,264,972**	**125,776,662**	**328,929,699**	**126,356,176**
815								
816								
817	Summary of Distribution Expense by Factor							
818		S			306,379,698	114,807,428	286,044,425	114,807,428
819		SNPD			42,885,274	10,969,234	42,885,274	11,548,748
820								
821	Total Distribution Expense by Factor				349,264,972	125,776,662	328,929,699	126,356,176
822								
823	901	Supervision						
824			S		-	-	-	-
825			CN		22,295,366	6,719,767	22,295,366	7,215,438
826				B2	22,295,366	6,719,767	22,295,366	7,215,438
827								
828	902	Meter Reading Expense						
829			S		8,372,328	2,151,766	7,278,297	2,151,766
830			CN		1,333,409	401,886	1,333,409	431,531
831				B2	9,705,738	2,553,652	8,611,706	2,583,297
832								
833	903	Customer Receipts & Collections						
834			S		11,146,428	2,270,062	7,065,640	2,270,062
835			CN		31,241,046	9,415,973	31,241,046	10,110,524
836				B2	42,387,475	11,686,034	38,306,687	12,380,585
837								
838	904	Uncollectible Accounts						
839			S		26,160,692	11,174,954	22,322,932	11,174,954
840			SG		-	-	-	-
841			CN		(8,401)	(2,532)	(8,401)	(2,719)
842				B2	26,152,291	11,172,422	22,314,531	11,172,235
843								
844	905	Misc. Customer Accounts Expense						
845			S		0	0	0	0
846			CN		-	-	-	-
847				B2	0	0	0	0
848								
849	**Total Customer Accounts Expense**			**B2**	**100,540,869**	**32,131,875**	**91,528,290**	**33,351,555**
850								
851	Summary of Customer Accts Exp by Factor							
852		S			45,679,449	15,596,781	36,666,869	15,596,781
853		CN			54,861,420	16,535,094	54,861,420	17,754,773
854		SG			-	-	-	-
855	Total Customer Accounts Expense by Factor				100,540,869	32,131,875	91,528,290	33,351,555
856								
857	907	Supervision						
858			S		-	-	-	-
859			CN		-	-	-	-
860				B2	-	-	-	-
861								
862	908	Customer Assistance						
863			S		238,785,971	2,328,091	235,189,497	2,328,091
864			CN		4,236,323	1,276,817	4,236,323	1,370,999
865								
866								
867				B2	243,022,294	3,604,908	239,425,819	3,699,090
868								
869	909	Informational & Instructional Adv						
870			S		2,147,201	662,140	1,899,860	662,140
871			CN		3,344,728	1,008,093	3,344,728	1,082,453
872				B2	5,491,929	1,670,232	5,244,589	1,744,592
873								
874	910	Misc. Customer Service						
875			S		-	-	-	-
876			CN		162,332	48,927	162,332	52,535
877								
878				B2	162,332	48,927	162,332	52,535
879								
880	**Total Customer Service Expense**			**B2**	**248,676,556**	**5,324,067**	**244,832,740**	**5,496,218**
881								
882								
883	Summary of Customer Service Exp by Factor							
884		S			240,933,172	2,990,231	237,089,357	2,990,231
885		CN			7,743,384	2,333,836	7,743,384	2,505,987
886								
887	Total Customer Service Expense by Factor			B2	248,676,556	5,324,067	244,832,740	5,496,218
888								
889								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
890	911	Supervision						
891			S		-	-	-	-
892			CN		-	-	-	-
893				B2	-	-	-	-
894								
895	912	Demonstration & Selling Expense						
896			S		-	-	-	-
897			CN		-	-	-	-
898				B2	-	-	-	-
899								
900	913	Advertising Expense						
901			S		-	-	-	-
902			CN		-	-	-	-
903				B2	-	-	-	-
904								
905	916	Misc. Sales Expense						
906			S		-	-	-	-
907			CN		-	-	-	-
908				B2	-	-	-	-
909								
910	**Total Sales Expense**			**B2**	**-**	**-**	**-**	**-**
911								
912								
913	Total Sales Expense by Factor							
914		S			-	-	-	-
915		CN			-	-	-	-
916	Total Sales Expense by Factor				-	-	-	-
917								
918	**Total Customer Service Exp Including Sales**			**B2**	**248,676,556**	**5,324,067**	**244,832,740**	**5,496,218**
919	920	Administrative & General Salaries						
920			S		49,671	(2,494)	49,671	(2,494)
921			CN		-	-	-	-
922			SO		93,332,638	26,048,105	93,332,638	28,015,526
923				B2	93,382,308	26,045,611	93,382,308	28,013,033
924								
925	921	Office Supplies & expenses						
926			S		35,487	(134,135)	25,215	(134,135)
927			CN		123,410	37,195	123,410	39,939
928			SO		21,284,582	5,940,291	21,284,582	6,388,963
929				B2	21,443,479	5,843,351	21,433,207	6,294,767
930								
931	922	A&G Expenses Transferred						
932			S		-	-	-	-
933			CN		-	-	-	-
934			SO		(48,264,904)	(13,470,200)	(48,266,631)	(14,488,127)
935				B2	(48,264,904)	(13,470,200)	(48,266,631)	(14,488,127)
936								
937	923	Outside Services						
938			S		2,486,532	77,189	1,425,060	77,189
939			CN		-	-	-	-
940			SO		50,042,122	13,966,201	50,042,122	15,021,073
941				B2	52,528,654	14,043,390	51,467,181	15,098,262
942								
943	924	Property Insurance						
944			S		48,633,919	44,234,652	47,349,217	44,234,652
945			SG		-	-	-	-
946			SO		5,519,539	1,540,442	5,519,539	1,656,792
947				B2	54,153,458	45,775,094	52,868,757	45,891,444
948								
949	925	Injuries & Damages						
950			S		26,193,033	26,193,033	26,193,033	26,193,033
951			SO		54,915,137	15,326,206	54,903,634	16,480,346
952				B2	81,108,170	41,519,239	81,096,668	42,673,380
953								
954	926	Employee Pensions & Benefits						
955			S		1,224,653	536,407	988,887	536,407
956			SG		-	-	-	-
957			SO		146,974,636	41,018,992	146,351,810	43,930,217
958				B2	148,199,288	41,555,399	147,340,697	44,466,624
959								
960	927	Franchise Requirements						
961			S		-	-	-	-
962			SO		-	-	-	-
963				B2	-	-	-	-
964								
965	928	Regulatory Commission Expense						
966			S		28,177,530	12,221,673	26,232,272	12,221,673
967			SE		-	-	-	-
968			SO		2,807,554	783,557	2,807,554	842,740
969			SG		4,871,219	1,352,035	4,871,219	1,459,198
970				B2	35,856,303	14,357,265	33,911,045	14,523,611
971								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
972	929	Duplicate Charges						
973			S		-	-	-	-
974			SO		(165,119,150)	(46,082,924)	(165,176,831)	(49,580,897)
975				B2	(165,119,150)	(46,082,924)	(165,176,831)	(49,580,897)
976								
977	930	Misc General Expenses						
978			S		(226,914)	(298,614)	(223,819)	(298,614)
979			CN		-	-	-	-
980			SG		(1,649,132)	(457,726)	(1,649,132)	(494,006)
981			SO		1,496,273	417,593	1,496,273	449,134
982				B2	(379,773)	(338,747)	(376,678)	(343,486)
983								
984	931	Rents						
985			S		116,895	83,392	111,815	83,392
986			SO		655,603	182,971	655,603	196,791
987				B2	772,498	266,364	767,417	280,184
988								
989	935	Maintenance of General Plant						
990			S		1,019,069	365,103	790,807	365,103
991			CN		86,540	26,083	86,540	28,007
992			SO		39,346,052	10,981,047	39,346,052	11,810,449
993				B2	40,451,661	11,372,233	40,223,398	12,203,559
994								
995	**Total Administrative & General Expense**			**B2**	**314,131,993**	**140,886,076**	**308,670,538**	**145,032,355**
996								
997	Summary of A&G Expense by Factor							
998		S			107,709,875	83,276,207	102,942,157	83,276,207
999		SE			-	-	-	-
1000		SO			202,990,081	56,652,282	202,296,344	60,723,009
1001		SG			3,222,087	894,309	3,222,087	965,193
1002		CN			209,950	63,278	209,950	67,946
1003	Total A&G Expense by Factor				314,131,993	140,886,076	308,670,538	145,032,355
1004								
1005	**Total O&M Expense**			**B2**	**2,588,595,571**	**1,135,057,645**	**2,532,894,688**	**1,149,861,887**
1006	403SP	Steam Depreciation						
1007			S		-	-	-	-
1008			SG		-	-	-	-
1009			SG		-	-	-	-
1010			SG		314,798,531	87,374,141	314,798,531	94,299,508
1011			SG		-	-	-	-
1012				B3	314,798,531	87,374,141	314,798,531	94,299,508
1013								
1014	403NP	Nuclear Depreciation						
1015			SG		-	-	-	-
1016				B3	-	-	-	-
1017								
1018	403HP	Hydro Depreciation						
1019			SG		-	-	-	-
1020			SG		-	-	-	-
1021			SG		31,451,236	8,729,471	31,451,236	9,421,379
1022			SG		10,812,805	3,001,156	10,812,805	3,239,031
1023			SG		4,163,031	1,155,473	4,163,031	1,247,057
1024				B3	46,427,073	12,886,101	46,427,073	13,907,467
1025								
1026	403XP	Solar Depreciation						
1027			S		152,271	126,881	152,271	126,881
1028			SG		-	-	-	-
1029				B3	152,271	126,881	152,271	126,881
1030								
1031	403WP	Wind Depreciation						
1032			S		-	-	-	-
1033			SG		189,581,254	52,619,366	170,340,655	51,026,413
1034				B3	189,581,254	52,619,366	170,340,655	51,026,413
1035								
1036	403RP	Other Renewable Depreciation						
1037			S		-	-	-	-
1038			SG		3,023,588	839,214	3,023,588	905,731
1039				B3	3,023,588	839,214	3,023,588	905,731
1040								
1041	403OP	Other Production Depreciation						
1042			S		-	-	-	-
1043			SG		-	-	-	-
1044			SG		75,499,184	20,955,232	62,470,454	18,713,344
1045			SG		-	-	-	-
1046			SG		-	-	-	-
1047				B3	75,499,184	20,955,232	62,470,454	18,713,344
1048								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
1049	403TP	Transmission Depreciation						
1050			S		(0)	(0)	(0)	(0)
1051			SG		-	-	-	-
1052			SG		-	-	-	-
1053			SG		217,813,885	60,455,495	211,773,291	63,437,771
1054				B3	217,813,885	60,455,495	211,773,291	63,437,771
1055								
1056								
1057								
1058	403	Distribution Depreciation						
1059	360	Land & Land Rights	S		993,008	157,551	971,509	157,551
1060	361	Structures	S		3,563,401	760,804	3,396,469	760,804
1061	362	Station Equipment	S		42,287,755	10,314,403	39,759,115	10,314,403
1062	362	Station Equipment	SG		-	-	-	-
1063	363	Storage Battery Equipment	S		4,657,790	1,507,218	4,433,023	1,507,218
1064	363	Storage Battery Equipment	SNPD		1,086,539	277,916	1,086,539	292,598
1065	363	Storage Battery Equipment	SO		-	-	-	-
1066	363	Storage Battery Equipment	SG		-	-	-	-
1067	364	Poles & Towers	S		70,217,547	20,549,030	64,785,952	20,549,030
1068	364	Poles & Towers	SG		-	-	-	-
1069	364	Poles & Towers	SNPD		-	-	-	-
1070	364	Poles & Towers	SO		-	-	-	-
1071	365	OH Conductors	S		33,581,971	9,533,952	30,723,617	9,533,952
1072	366	UG Conduit	S		15,083,951	2,837,885	14,395,384	2,837,885
1073	367	UG Conductor	S		31,297,392	6,290,403	30,284,064	6,290,403
1074	368	Line Trans	S		50,132,244	14,099,495	46,638,694	14,099,495
1075	369	Services	S		31,488,271	9,137,572	29,293,394	9,137,572
1076	370	Meters	S		15,574,330	2,220,557	14,673,671	2,220,557
1077	371	Inst Cust Prem	S		513,302	127,873	490,795	127,873
1078	372	Leased Property	S		-	-	-	-
1079	373	Street Lighting	S		2,757,903	699,721	2,631,694	699,721
1080				B3	303,235,403	78,514,380	283,563,923	78,529,063
1081								
1082	403GP	General Depreciation						
1083			S		7,490,201	2,146,608	7,004,834	2,146,608
1084			SG		-	-	-	-
1085			SG		-	-	-	-
1086			SE		95,658	25,658	95,658	27,503
1087			CN		6,972,479	2,101,488	6,972,479	2,256,500
1088			SG		2,703,736	750,437	2,671,522	800,268
1089			SO		68,077,147	18,999,577	68,077,147	20,434,621
1090			SG		-	-	-	-
1091			SG		-	-	-	-
1092				B3	85,339,221	24,023,768	84,821,640	25,665,500
1093								
1094	403GV0	General Vehicles						
1095			SG		-	-	-	-
1096				B3	-	-	-	-
1097								
1098	403MP	Mining Depreciation						
1099			SE		-	-	-	-
1100				B3	-	-	-	-
1101								
1102	403EP	Experimental Plant Depreciation						
1103			SG		-	-	-	-
1104			SG		-	-	-	-
1105				B3	-	-	-	-
1106	4031	ARO Depreciation						
1107			S		-	-	-	-
1108				B3	-	-	-	-
1109								
1110								
1111	**Total Depreciation Expense**			**B3**	**1,235,870,409**	**337,794,580**	**1,177,371,425**	**346,611,678**
1112								
1113	Summary	S			309,791,336	80,509,953	289,634,489	80,509,953
1114		DGP			-	-	-	-
1115		DGU			-	-	-	-
1116		SG			849,847,250	235,879,988	811,505,113	243,090,503
1117		SO			68,077,147	18,999,577	68,077,147	20,434,621
1118		CN			6,972,479	2,101,488	6,972,479	2,256,500
1119		SE			95,658	25,658	95,658	27,503
1120		SNPD			1,086,539	277,916	1,086,539	292,598
1121		SSGCT			-	-	-	-
1122	Total Depreciation Expense By Factor				1,235,870,409	337,794,580	1,177,371,425	346,611,678
1123								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
1124	404GP	Amort of LT Plant - Leasehold Improvements						
1125			S		180,342	75,382	78,846	75,382
1126			SG		-	-	-	-
1127			SO		34,180	9,539	34,180	10,260
1128			SG		-	-	-	-
1129			CN		-	-	-	-
1130			SG		-	-	-	-
1131				B4	214,522	84,921	113,025	85,642
1132								
1133	404SP	Amort of LT Plant - Cap Lease Steam						
1134			SG		-	-	-	-
1135			SG		-	-	-	-
1136				B4	-	-	-	-
1137								
1138	404IP	Amort of LT Plant - Intangible Plant						
1139			S		160,301	8,838	160,301	8,838
1140			SE		-	-	-	-
1141			SG		5,500,965	1,526,824	4,950,800	1,483,037
1142			SO		-	-	-	-
1143			CN		-	-	-	-
1144			SG		2,682,975	744,675	2,682,975	803,699
1145			SG		255,549	70,929	255,549	76,551
1146			SG		-	-	-	-
1147			SG		-	-	-	-
1148			SG		-	-	-	-
1149			SG		-	-	-	-
1150				B4	8,599,790	2,351,266	8,049,624	2,372,125
1151								
1152	404MP	Amort of LT Plant - Mining Plant						
1153			SE		-	-	-	-
1154				B4	-	-	-	-
1155								
1156	404XP	Amort of LT Plant - Solar Plant						
1157			S		-	-	-	-
1158			SG		-	-	-	-
1159				B4	-	-	-	-
1160								
1161	404WP	Amort of LT Plant - Wind Plant						
1162			S		-	-	-	-
1163			SG		-	-	-	-
1164				B4	-	-	-	-
1165								
1166	404RP	Amort of LT Plant - Other Renewable Plant						
1167			S		-	-	-	-
1168			SG		-	-	-	-
1169				B4	-	-	-	-
1170								
1171	404OP	Amort of LT Plant - Other Plant						
1172			S		-	-	-	-
1173				B4	-	-	-	-
1174								
1175								
1176	404HP	Amortization of Other Electric Plant						
1177			SG		314,732	87,356	314,732	94,280
1178			SG		-	-	-	-
1179			SG		-	-	-	-
1180				B4	314,732	87,356	314,732	94,280
1181								
1182	**Total Amortization of Limited Term Plant**			**B4**	**9,129,044**	**2,523,544**	**8,477,382**	**2,552,047**
1183								
1184								
1185	405	Amortization of Other Electric Plant						
1186			S		-	-	-	-
1187								
1188				B4	-	-	-	-
1189								
1190	406	Amortization of Plant Acquisition Adj						
1191			S		301,635	-	301,635	-
1192			SG		-	-	-	-
1193			SG		-	-	-	-
1194			SG		75,351	20,914	75,351	22,572
1195			SO		-	-	-	-
1196				B4	376,987	20,914	376,987	22,572

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
1197	407	Amort of Prop Losses, Unrec Plant, etc						
1198			S		(1,371,579)	(6,805,180)	(1,371,579)	(6,805,180)
1199			SO		-	-	-	-
1200			SG-P		-	-	-	-
1201			SE		-	-	-	-
1202			SG		14,287,273	3,965,515	14,287,273	4,279,826
1203			TROJP		-	-	-	-
1204				B4	12,915,695	(2,839,665)	12,915,695	(2,525,354)
1205								
1206	**Total Amortization Expense**			**B4**	**22,421,726**	**(295,207)**	**21,770,064**	**49,265**
1207								
1208								
1209								
1210	Summary of Amortization Expense by Factor							
1211		S			(729,300)	(6,720,960)	(830,796)	(6,720,960)
1212		SE			-	-	-	-
1213		TROJP			-	-	-	-
1214		DGP			-	-	-	-
1215		DGU			-	-	-	-
1216		SO			34,180	9,539	34,180	10,260
1217		SSGCT			-	-	-	-
1218		SSGCH			-	-	-	-
1219		CN			-	-	-	-
1220		SG			23,116,846	6,416,213	22,566,680	6,759,964
1221	Total Amortization Expense by Factor				22,421,726	(295,207)	21,770,064	49,265
1222	408	Taxes Other Than Income						
1223			S		57,929,367	53,275,467	57,907,315	53,275,467
1224			GPS		185,102,997	51,698,451	177,502,997	53,296,559
1225			SO		22,024,729	6,146,858	3,348,824	1,005,212
1226			SE		1,159,659	311,053	1,159,659	333,419
1227			SG		5,224,557	1,450,106	5,224,557	1,565,043
1228			OPRV-ID		-	-	-	-
1229			EXCTAX		-	-	-	-
1230			SG		-	-	-	-
1231								
1232								
1233								
1234	**Total Taxes Other Than Income**			**B5**	**271,441,309**	**112,881,934**	**245,143,352**	**109,475,699**
1235								
1236								
1237	41140	Deferred Investment Tax Credit - Fed						
1238			DGU		(514)	-	(514)	-
1239								
1240				B7	(514)	-	(514)	-
1241								
1242	41141	Deferred Investment Tax Credit - Idaho						
1243			DGU		-	-	-	-
1244								
1245				B7	-	-	-	-
1246								
1247	**Total Deferred ITC**			**B7**	**(514)**	**-**	**(514)**	**-**
1248								
1249								
1250	427	Interest on Long-Term Debt						
1251			S		647,000,245	178,098,945	614,529,809	180,953,340
1252			SNP		-	-	-	-
1253				B6	647,000,245	178,098,945	614,529,809	180,953,340
1254								
1255	428	Amortization of Debt Disc & Exp						
1256			SNP		7,525,246	1,998,446	7,525,246	2,138,135
1257				B6	7,525,246	1,998,446	7,525,246	2,138,135
1258								
1259	429	Amortization of Premium on Debt						
1260			SNP		-	-	-	-
1261				B6	-	-	-	-
1262								
1263	431	Other Interest Expense						
1264			OTH		-	-	-	-
1265			SO		-	-	-	-
1266			SNP		48,749,096	12,946,080	48,749,096	13,850,999
1267				B6	48,749,096	12,946,080	48,749,096	13,850,999
1268								
1269	432	AFUDC - Borrowed						
1270			SNP		(107,026,208)	(28,422,473)	(107,026,208)	(30,409,177)
1271					(107,026,208)	(28,422,473)	(107,026,208)	(30,409,177)
1272								
1273		Total Elec. Interest Deductions for Ta:		B6	596,248,378	164,620,998	563,777,943	166,533,297
1274								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
1275		Non-Regulated Portion of Interest						
1276			427 NUTIL		-	-	-	-
1277			428 NUTIL		-	-	-	-
1278			429 NUTIL		-	-	-	-
1279			431 NUTIL		-	-	-	-
1280								
1281		Total Non-Regulated Interest			-	-	-	-
1282								
1283		Total Interest Deductions for Tax		B6	596,248,378	164,620,998	563,777,943	166,533,297
1284								
1285								
1286	419	Interest & Dividends						
1287			S		-	-	-	-
1288			SNP		(10,642,278)	(2,826,222)	(10,642,278)	(3,023,773)
1289		Total Operating Deductions for Tax		B6	(10,642,278)	(2,826,222)	(10,642,278)	(3,023,773)
1290								
1291								
1292	41010	Deferred Income Tax - Federal-DR						
1293			S		(92,330,595)	(3,210,509)	(93,698,499)	(3,257,962)
1294			TROJD		-	-	-	-
1295			SG		-	-	-	-
1296			SO		(6,586,584)	(1,838,243)	(6,683,936)	(2,006,308)
1297			SNP		3,795,050	1,007,835	3,851,142	1,094,219
1298			SE		-	-	-	-
1299			SG		8,381,975	2,326,465	8,505,864	2,547,975
1300			GPS		4,198,068	1,172,502	4,260,117	1,279,131
1301			DITEXP		-	-	-	-
1302			BADDEBT		-	-	-	-
1303			CN		-	-	-	-
1304			IBT		-	-	-	-
1305			CIAC		-	-	-	-
1306			SCHMDEXP		-	-	-	-
1307			TAXDEPR		356,980,970	98,919,335	350,074,724	103,920,327
1308			SNPD		(1)	(0)	(1)	(0)
1309				B7	274,438,884	98,377,386	266,309,411	103,577,382
1310								
1311								
1312								
1313	41110	Deferred Income Tax - Federal-CR						
1314			S		(67,838,101)	(6,989,069)	(57,687,945)	(6,940,656)
1315			SE		3,892,588	1,044,101	3,950,122	1,135,718
1316			SG		-	-	-	-
1317			SNP		(2,738,332)	(727,207)	(2,778,806)	(789,537)
1318			SG		2,957,649	820,913	2,790,030	835,768
1319			GPS		-	-	-	-
1320			SO		3,447,559	962,176	3,478,786	1,044,222
1321			SNPD		-	-	-	-
1322			BADDEBT		0	0	0	0
1323			SG		-	-	-	-
1324			SG		-	-	-	-
1325			TROJD		(9,103)	(2,511)	(9,238)	(2,747)
1326			CN		-	-	-	-
1327			CIAC		(9,287,598)	(2,375,590)	(9,424,872)	(2,538,062)
1328			SCHMDEXP		(301,263,024)	(82,082,837)	(296,011,715)	(86,856,213)
1329			TAXDEPR		-	-	-	-
1330				B7	(370,838,361)	(89,350,025)	(355,693,638)	(94,111,508)
1331								
1332	**Total Deferred Income Taxes**			**B7**	**(96,399,478)**	**9,027,360**	**(89,384,227)**	**9,465,875**
1333	SCHMAF	Additions - Flow Through						
1334			S		-	-	-	-
1335			SNP		-	-	-	-
1336			SO		-	-	-	-
1337			SE		-	-	-	-
1338			TROJP		-	-	-	-
1339			SG		-	-	-	-
1340				B6	-	-	-	-
1341								
1342	SCHMAP	Additions - Permanent						
1343			S		-	-	-	-
1344			SE		17,722	4,753	17,722	5,095
1345			SNP		-	-	-	-
1346			SO		2,228,878	622,055	2,228,878	669,039
1347			SG		-	-	-	-
1348			SCHMDEXP		134,376	36,612	134,376	39,429
1349				B6	2,380,975	663,421	2,380,975	713,563

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
1350								
1351	SCHMAT	Additions - Temporary						
1352			S		11,923,870	(13,389,750)	8,796,996	(13,389,750)
1353			SG		-	-	-	-
1354			CIAC		37,775,038	9,662,133	37,775,038	10,172,592
1355			SNP		11,137,499	2,957,736	11,137,499	3,164,479
1356			TROJD		37,028	10,216	37,028	11,012
1357			SG		-	-	-	-
1358			SE		(15,832,138)	(4,246,621)	(15,832,138)	(4,551,972)
1359			SG		12,102,484	3,359,114	12,102,484	3,625,361
1360			GPS		0	0	0	0
1361			SO		(11,127,808)	(3,105,648)	(11,127,808)	(3,340,218)
1362			SNPD		-	-	-	-
1363			BADDEBT		0	0	0	0
1364			CN		-	-	-	-
1365			SCHMDEXP		1,225,313,887	333,851,922	1,186,419,701	348,121,094
1366				B6	1,271,329,860	329,099,103	1,229,308,801	343,812,598
1367								
1368	TOTAL SCHEDULE - M ADDITIONS			B6	1,273,710,835	329,762,524	1,231,689,776	344,526,161
1369								
1370	SCHMDF	Deductions - Flow Through						
1371			S		-	-	-	-
1372			DGP		-	-	-	-
1373			DGU		-	-	-	-
1374				B6	-	-	-	-
1375	SCHMDP	Deductions - Permanent						
1376			S		-	-	-	-
1377			SE		5,620,656	1,507,617	5,620,656	1,616,021
1378			SNP		0	0	0	0
1379			SCHMDEXP		-	-	-	-
1380			SG		-	-	-	-
1381			SO		-	-	-	-
1382				B6	5,620,656	1,507,617	5,620,656	1,616,021
1383								
1384	SCHMDT	Deductions - Temporary						
1385			S		(375,532,146)	(13,057,961)	(375,545,058)	(13,057,961)
1386			BADDEBT		-	-	-	-
1387			SNP		15,435,437	4,099,120	15,435,437	4,385,645
1388			CN		-	-	-	-
1389			SG		-	-	-	-
1390			DGP		-	-	-	-
1391			SE		(0)	(0)	(0)	(0)
1392			SG		34,091,648	9,462,333	34,091,648	10,212,327
1393			GPS		17,074,616	4,768,865	17,074,616	5,126,777
1394			SO		(26,789,325)	(7,476,604)	(26,789,325)	(8,041,314)
1395			TAXDEPR		1,451,933,046	402,330,276	1,403,105,106	416,514,338
1396			SNPD		0	0	0	0
1397				B6	1,116,213,277	400,126,029	1,067,372,425	415,139,812
1398								
1399	TOTAL SCHEDULE - M DEDUCTIONS			B6	1,121,833,933	401,633,646	1,072,993,081	416,755,833
1400								
1401	**TOTAL SCHEDULE - M ADJUSTMENTS**			**B6**	**151,876,902**	**(71,871,122)**	**158,696,696**	**(72,229,672)**
1402								
1403								
1404								
1405	40911	State Income Taxes						
1406					112,048,550	4,648,805	110,044,270	4,580,668
1407			S		9,229,930	492,784	9,229,930	492,784
1408		PTC	SG		-	-	-	-
1409			IBT		-	-	-	-
1410	**Total State Tax Expense**				**121,278,480**	**5,141,589**	**119,274,201**	**5,073,452**
1411								
1412								
1413	Calculation of Taxable Income:							
1414		Operating Revenues			7,019,076,002	1,921,396,720	6,571,491,962	1,933,219,689
1415		Operating Deductions:						
1416		O & M Expenses			2,588,595,571	1,135,057,645	2,532,894,688	1,149,861,887
1417		Depreciation Expense			1,235,870,409	337,794,580	1,177,371,425	346,611,678
1418		Amortization Expense			22,421,726	(295,207)	21,770,064	49,265
1419		Taxes Other Than Income			271,441,309	112,881,934	245,143,352	109,475,699
1420		Interest & Dividends (AFUDC-Equity)			(10,642,278)	(2,826,222)	(10,642,278)	(3,023,773)
1421		Misc Revenue & Expense			(1,011,940)	(104,716)	(1,011,940)	(131,398)
1422		Total Operating Deductions			4,106,674,797	1,582,508,013	3,965,525,311	1,602,843,357
1423		Other Deductions:						
1424		Interest Deductions			596,248,378	164,620,998	563,777,943	166,533,297
1425		Interest on PCRBS			-	-	-	-
1426		Schedule M Adjustments			151,876,902	(71,871,122)	158,696,696	(72,229,672)
1427								
1428		Income Before State Taxes			2,468,029,728	102,396,587	2,200,885,404	91,613,363
1429								
1430		State Income Taxes			121,278,480	5,141,589	119,274,201	5,073,452

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
1431								
1432	Total Taxable Income				2,346,751,248	97,254,998	2,081,611,203	86,539,911
1433								
1434	Tax Rate				21.0%	21.0%	21.0%	21.0%
1435								
1436	Federal Income Tax - Calculated				492,817,762	20,423,550	437,138,353	18,173,381
1437								
1438	Adjustments to Calculated Tax:							
1439	40910		SE		(13,813)	(3,705)	(13,813)	(3,971)
1440	40910	PTC	SG		0	0	0	0
1441	40910		SO		(55,263)	(15,423)	(55,263)	(16,588)
1442	40910	PTC	S		(81,033,112)	(81,033,112)	(81,033,112)	(81,033,112)
1443	**Federal Income Tax Expense**				**411,715,574**	**(60,628,691)**	**356,036,165**	**(62,880,290)**
1444								
1445	**Total Operating Expenses**				**4,553,911,138**	**1,538,874,495**	**4,362,093,214**	**1,557,526,166**
1446	310	Land and Land Rights						
1447			SG		-	-	-	-
1448			SG		-	-	-	-
1449			SG		50,518,330	14,021,653	50,518,330	15,133,024
1450			S		-	-	-	-
1451			SG		-	-	-	-
1452				B8	50,518,330	14,021,653	50,518,330	15,133,024
1453								
1454	311	Structures and Improvements						
1455			SG		-	-	-	-
1456			SG		-	-	-	-
1457			SG		1,049,095,490	291,182,482	1,049,095,490	314,261,914
1458			SG		-	-	-	-
1459				B8	1,049,095,490	291,182,482	1,049,095,490	314,261,914
1460								
1461	312	Boiler Plant Equipment						
1462			SG		-	-	-	-
1463			SG		-	-	-	-
1464			SG		4,432,182,022	1,230,177,591	4,432,182,022	1,327,682,768
1465			SG		-	-	-	-
1466				B8	4,432,182,022	1,230,177,591	4,432,182,022	1,327,682,768
1467								
1468	314	Turbogenerator Units						
1469			SG		-	-	-	-
1470			SG		-	-	-	-
1471			SG		965,486,229	267,976,251	965,486,229	289,216,332
1472			SG		-	-	-	-
1473				B8	965,486,229	267,976,251	965,486,229	289,216,332
1474								
1475	315	Accessory Electric Equipment						
1476			SG		-	-	-	-
1477			SG		-	-	-	-
1478			SG		441,152,287	122,444,352	441,152,287	132,149,421
1479			SG		-	-	-	-
1480				B8	441,152,287	122,444,352	441,152,287	132,149,421
1481								
1482								
1483								
1484	316	Misc Power Plant Equipment						
1485			SG		-	-	-	-
1486			SG		-	-	-	-
1487			SG		32,916,409	9,136,138	32,916,409	9,860,278
1488			SG		-	-	-	-
1489				B8	32,916,409	9,136,138	32,916,409	9,860,278
1490								
1491	317	Steam Plant ARO						
1492			S		-	-	-	-
1493				B8	-	-	-	-
1494								
1495	SP	Unclassified Steam Plant - Account 300						
1496			SG		176,015,597	48,854,140	176,015,597	52,726,371
1497				B8	176,015,597	48,854,140	176,015,597	52,726,371
1498								
1499								
1500	**Total Steam Production Plant**			**B8**	**7,147,366,363**	**1,983,792,608**	**7,147,366,363**	**2,141,030,109**
1501								
1502								
1503	Summary of Steam Production Plant by Factor							
1504		S			-	-	-	-
1505		DGP			-	-	-	-
1506		DGU			-	-	-	-
1507		SG			7,147,366,363	1,983,792,608	7,147,366,363	2,141,030,109
1508		SSGCH			-	-	-	-
1509	Total Steam Production Plant by Factor				7,147,366,363	1,983,792,608	7,147,366,363	2,141,030,109

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
1510	320	Land and Land Rights						
1511			SG		-	-	-	-
1512			SG		-	-	-	-
1513				B8	-	-	-	-
1514								
1515	321	Structures and Improvements						
1516			SG		-	-	-	-
1517			SG	B8	-	-	-	-
1518					-	-	-	-
1519								
1520	322	Reactor Plant Equipment						
1521			SG		-	-	-	-
1522			SG		-	-	-	-
1523				B8	-	-	-	-
1524								
1525	323	Turbogenerator Units						
1526			SG		-	-	-	-
1527			SG		-	-	-	-
1528				B8	-	-	-	-
1529								
1530	324	Land and Land Rights						
1531			SG		-	-	-	-
1532			SG		-	-	-	-
1533				B8	-	-	-	-
1534								
1535	325	Misc. Power Plant Equipment						
1536			SG		-	-	-	-
1537			SG		-	-	-	-
1538				B8	-	-	-	-
1539								
1540								
1541	NP	Unclassified Nuclear Plant - Acct 300						
1542			SG		-	-	-	-
1543				B8	-	-	-	-
1544								
1545								
1546	**Total Nuclear Production Plant**			**B8**	**-**	**-**	**-**	**-**
1547								
1548								
1549								
1550	Summary of Nuclear Production Plant by Factor							
1551		DGP			-	-	-	-
1552		DGU			-	-	-	-
1553		SG			-	-	-	-
1554		SG-P			-	-	-	-
1555	Total Nuclear Plant by Factor				-	-	-	-
1556								
1557	330	Land and Land Rights						
1558			SG		-	-	-	-
1559			SG		-	-	-	-
1560			SG		30,913,012	8,580,084	30,913,012	9,260,151
1561			SG		6,598,315	1,831,400	6,598,315	1,976,559
1562				B8	37,511,327	10,411,484	37,511,327	11,236,710
1563								
1564	331	Structures and Improvements						
1565			SG		-	-	-	-
1566			SG		-	-	-	-
1567			SG		301,728,202	83,746,396	301,728,202	90,384,224
1568			SG		23,286,122	6,463,197	23,286,122	6,975,477
1569				B8	325,014,324	90,209,593	325,014,324	97,359,701
1570								
1571	332	Reservoirs, Dams & Waterways						
1572			SG		-	-	-	-
1573			SG		-	-	-	-
1574			SG		569,002,622	157,929,948	569,002,622	170,447,642
1575			SG		144,760,734	40,179,174	144,760,734	43,363,818
1576			SG		(1,000,472)	(277,687)	(1,000,472)	(299,697)
1577				B8	712,762,883	197,831,434	712,762,883	213,511,763
1578								
1579	333	Water Wheel, Turbines, & Generators						
1580			SG		-	-	-	-
1581			SG		-	-	-	-
1582			SG		81,146,050	22,522,553	81,146,050	24,307,714
1583			SG		51,284,522	14,234,314	51,284,522	15,362,540
1584				B8	132,430,572	36,756,866	132,430,572	39,670,254
1585								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
1586	334	Accessory Electric Equipment						
1587			SG		-	-	-	-
1588			SG		-	-	-	-
1589			SG		13,047,000	3,621,270	13,047,000	3,908,296
1590			SG		58,178,441	16,147,761	58,178,441	17,427,649
1591			SG		14,716,774	4,084,725	14,716,774	4,408,485
1592				B8	85,942,215	23,853,756	85,942,215	25,744,430
1593								
1594								
1595								
1596	335	Misc. Power Plant Equipment						
1597			SG		-	-	-	-
1598			SG		-	-	-	-
1599			SG		3,230,593	896,670	3,230,593	967,741
1600			SG		219,614	60,955	219,614	65,786
1601				B8	3,450,207	957,625	3,450,207	1,033,527
1602								
1603	336	Roads, Railroads & Bridges						
1604			SG		-	-	-	-
1605			SG		-	-	-	-
1606			SG		23,403,109	6,495,667	23,403,109	7,010,521
1607			SG		4,492,225	1,246,843	4,492,225	1,345,669
1608				B8	27,895,334	7,742,510	27,895,334	8,356,190
1609								
1610	337	Hydro Plant ARO						
1611			S		-	-	-	-
1612				B8	-	-	-	-
1613								
1614	HP	Unclassified Hydro Plant - Acct 300						
1615			S		-	-	-	-
1616			SG		-	-	-	-
1617			SG		-	-	-	-
1618			SG		-	-	-	-
1619				B8	-	-	-	-
1620								
1621	**Total Hydraulic Production Plant**			**B8**	**1,325,006,862**	**367,763,269**	**1,325,006,862**	**396,912,575**
1622								
1623	Summary of Hydraulic Plant by Factor							
1624		S			-	-	-	-
1625		SG			1,325,006,862	367,763,269	1,325,006,862	396,912,575
1626		DGP			-	-	-	-
1627		DGU			-	-	-	-
1628	Total Hydraulic Plant by Factor				1,325,006,862	367,763,269	1,325,006,862	396,912,575
1629								
1630	338XP	Solar Plant						
1631			S		1,477,691	919,203	1,477,691	919,203
1632			SG		56,322	15,632	56,322	16,872
1633				B8	1,534,013	934,836	1,534,013	936,075
1634								
1635								
1636	**Total Solar Plant**			**B8**	**1,534,013**	**934,836**	**1,534,013**	**936,075**
1637								
1638	Summary of Solar Plant by Factor							
1639		S			1,477,691	919,203	1,477,691	919,203
1640		SG			56,322	15,632	56,322	16,872
1641	Total Solar Plant by Factor				1,534,013	934,836	1,534,013	936,075
1642								
1643	338WP	Wind Plant						
1644			S		-	-	-	-
1645			SG		4,750,040,478	1,318,401,032	4,267,965,027	1,278,490,728
1646				B8	4,750,040,478	1,318,401,032	4,267,965,027	1,278,490,728
1647								
1648								
1649	**Total Wind Plant**			**B8**	**4,750,040,478**	**1,318,401,032**	**4,267,965,027**	**1,278,490,728**
1650								
1651	Summary of Wind Plant by Factor							
1652		S			-	-	-	-
1653		SG			4,750,040,478	1,318,401,032	4,267,965,027	1,278,490,728
1654	Total Wind Plant by Factor				4,750,040,478	1,318,401,032	4,267,965,027	1,278,490,728
1655								
1656	339	Other Renewable Plant						
1657			S		-	-	-	-
1658			SG		159,468,649	44,261,440	159,468,649	47,769,648
1659				B8	159,468,649	44,261,440	159,468,649	47,769,648
1660								
1661	**Total Other Renewable Plant**			**B8**	**159,468,649**	**44,261,440**	**159,468,649**	**47,769,648**
1662								
1663	Summary of Other Renewable Plant by Factor							
1664		S			-	-	-	-
1665		SG			159,468,649	44,261,440	159,468,649	47,769,648
1666	Total Other Renewable Plant by Factor				159,468,649	44,261,440	159,468,649	47,769,648
1667								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
1668	340	Land and Land Rights						
1669			S		-	-	-	-
1670			SG		39,257,634	10,896,182	35,527,107	10,642,326
1671			SG		-	-	-	-
1672			SG		-	-	-	-
1673				B8	39,257,634	10,896,182	35,527,107	10,642,326
1674								
1675	341	Structures and Improvements						
1676			S		-	-	-	-
1677			SG		175,538,274	48,721,657	150,864,940	45,192,363
1678			SG		-	-	-	-
1679			SG		-	-	-	-
1680			SG		-	-	-	-
1681				B8	175,538,274	48,721,657	150,864,940	45,192,363
1682								
1683	342	Fuel Holders, Producers & Accessories						
1684			SG		16,439,353	4,562,837	14,842,007	4,445,999
1685			SG		-	-	-	-
1686			SG		-	-	-	-
1687				B8	16,439,353	4,562,837	14,842,007	4,445,999
1688								
1689	343	Prime Movers						
1690			S		-	-	-	-
1691			SG		-	-	-	-
1692			SG		-	-	-	-
1693			SG		1,221,185,188	338,946,967	998,827,811	299,203,974
1694			SG		-	-	-	-
1695				B8	1,221,185,188	338,946,967	998,827,811	299,203,974
1696								
1697	344	Generators						
1698			S		-	-	-	-
1699			SG		-	-	-	-
1700			SG		435,567,770	120,894,338	359,154,560	107,586,583
1701			SG		-	-	-	-
1702				B8	435,567,770	120,894,338	359,154,560	107,586,583
1703								
1704	345	Accessory Electric Plant						
1705			S		-	-	-	-
1706			SG		217,908,917	60,481,872	178,631,413	53,509,952
1707			SG		-	-	-	-
1708			SG		-	-	-	-
1709			SG		-	-	-	-
1710				B8	217,908,917	60,481,872	178,631,413	53,509,952
1711								
1712								
1713								
1714	346	Misc. Power Plant Equipment						
1715			SG		12,977,877	3,602,084	9,709,047	2,908,395
1716			SG		-	-	-	-
1717			SG		-	-	-	-
1718				B8	12,977,877	3,602,084	9,709,047	2,908,395
1719								
1720	347	Other Production ARO						
1721			S		-	-	-	-
1722				B8	-	-	-	-
1723								
1724	OP	Unclassified Other Prod Plant-Acct 300						
1725			S		-	-	-	-
1726			SG		-	-	-	-
1727					-	-	-	-
1728								
1729	**Total Other Production Plant**			**B8**	**2,118,875,013**	**588,105,936**	**1,747,556,885**	**523,489,593**
1730								
1731	Summary of Other Production Plant by Factor							
1732			S		-	-	-	-
1733			DGU		-	-	-	-
1734			SG		2,118,875,013	588,105,936	1,747,556,885	523,489,593
1735			SSGCT		-	-	-	-
1736	Total of Other Production Plant by Factor				2,118,875,013	588,105,936	1,747,556,885	523,489,593
1737								
1738	Experimental Plant							
1739	103	Experimental Plant						
1740			SG		-	-	-	-
1741	**Total Experimental Production Plant**			**B8**	**-**	**-**	**-**	**-**
1742								
1743	**Total Production Plant**			**B8**	**15,502,291,377**	**4,303,259,121**	**14,648,897,797**	**4,388,628,728**
1744	350	Land and Land Rights						
1745			SG		-	-	-	-
1746			SG		-	-	-	-
1747			SG		439,915,244	122,101,004	432,447,058	129,541,725
1748				B8	439,915,244	122,101,004	432,447,058	129,541,725
1749								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
1750	351	Energy Storage						
1751			S		-	-	-	-
1752			SG		292,593,500	81,211,007	281,162,678	84,223,717
1753					292,593,500	81,211,007	281,162,678	84,223,717
1754								
1755	352	Structures and Improvements						
1756			S		-	-	-	-
1757			SG		-	-	-	-
1758			SG		-	-	-	-
1759			SG		475,225,563	131,901,586	458,795,889	137,434,653
1760				B8	475,225,563	131,901,586	458,795,889	137,434,653
1761								
1762	353	Station Equipment						
1763			SG		-	-	-	-
1764			SG		-	-	-	-
1765			SG		2,995,470,086	831,409,936	2,877,227,569	861,888,218
1766				B8	2,995,470,086	831,409,936	2,877,227,569	861,888,218
1767								
1768	354	Towers and Fixtures						
1769			SG		-	-	-	-
1770			SG		-	-	-	-
1771			SG		2,589,458,008	718,718,951	2,583,273,558	773,832,792
1772				B8	2,589,458,008	718,718,951	2,583,273,558	773,832,792
1773								
1774	355	Poles and Fixtures						
1775			S		0	0	0	0
1776			SG		-	-	-	-
1777			SG		2,433,431,177	675,412,807	2,363,922,824	708,125,159
1778				B8	2,433,431,177	675,412,807	2,363,922,824	708,125,159
1779								
1780	356	Clearing and Grading						
1781			SG		-	-	-	-
1782			SG		-	-	-	-
1783			SG		2,376,247,353	659,541,109	2,302,846,004	689,829,285
1784				B8	2,376,247,353	659,541,109	2,302,846,004	689,829,285
1785								
1786	357	Underground Conduit						
1787			SG		-	-	-	-
1788			SG		-	-	-	-
1789			SG		3,924,286	1,089,208	3,922,194	1,174,913
1790				B8	3,924,286	1,089,208	3,922,194	1,174,913
1791								
1792	358	Underground Conductors						
1793			SG		-	-	-	-
1794			SG		-	-	-	-
1795			SG		9,083,639	2,521,216	9,083,639	2,721,050
1796				B8	9,083,639	2,521,216	9,083,639	2,721,050
1797								
1798	359	Roads and Trails						
1799			SG		-	-	-	-
1800			SG		-	-	-	-
1801			SG		12,141,468	3,369,934	12,088,388	3,621,138
1802				B8	12,141,468	3,369,934	12,088,388	3,621,138
1803								
1804	TP	Unclassified Trans Plant - Acct 300						
1805			SG		691,399,059	191,901,782	677,297,117	202,887,812
1806				B8	691,399,059	191,901,782	677,297,117	202,887,812
1807								
1808	TS0	Unclassified Trans Sub Plant - Acct 300						
1809			SG		-	-	-	-
1810				B8	-	-	-	-
1811								
1812	**Total Transmission Plant**			**B8**	**12,318,889,382**	**3,419,178,541**	**12,002,066,918**	**3,595,280,462**
1813	Summary of Transmission Plant by Factor							
1814		DGP			-	-	-	-
1815		DGU			-	-	-	-
1816		SG			12,318,889,382	3,419,178,541	12,002,066,918	3,595,280,462
1817	Total Transmission Plant by Factor				12,318,889,382	3,419,178,541	12,002,066,918	3,595,280,462
1818	360	Land and Land Rights						
1819			S		96,593,548	18,539,263	93,449,745	18,539,263
1820				B8	96,593,548	18,539,263	93,449,745	18,539,263
1821								
1822	361	Structures and Improvements						
1823			S		183,962,000	42,930,779	173,819,197	42,930,779
1824				B8	183,962,000	42,930,779	173,819,197	42,930,779
1825								
1826	362	Station Equipment						
1827			S		1,530,031,721	356,583,387	1,430,357,045	356,583,387
1828				B8	1,530,031,721	356,583,387	1,430,357,045	356,583,387
1829								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
1830	363	Storage Battery Equipment						
1831			S		200,760,284	67,908,356	191,389,760	67,908,356
1832			CN		10,802,634	3,255,887	10,802,634	3,496,051
1833			SNPD		37,730,467	9,650,733	37,730,467	10,160,590
1834				B8	249,293,386	80,814,976	239,922,861	81,564,997
1835								
1836	364	Poles, Towers & Fixtures						
1837			S		2,179,617,565	695,359,584	2,014,957,449	695,359,584
1838				B8	2,179,617,565	695,359,584	2,014,957,449	695,359,584
1839								
1840	365	Overhead Conductors						
1841			S		1,400,376,450	450,309,947	1,282,959,019	450,309,947
1842				B8	1,400,376,450	450,309,947	1,282,959,019	450,309,947
1843								
1844	366	Underground Conduit						
1845			S		650,039,637	146,829,263	621,121,235	146,829,263
1846				B8	650,039,637	146,829,263	621,121,235	146,829,263
1847								
1848								
1849								
1850								
1851	367	Underground Conductors						
1852			S		1,496,664,550	285,114,054	1,451,408,556	285,114,054
1853				B8	1,496,664,550	285,114,054	1,451,408,556	285,114,054
1854								
1855	368	Line Transformers						
1856			S		2,057,720,934	610,447,978	1,909,995,930	610,447,978
1857				B8	2,057,720,934	610,447,978	1,909,995,930	610,447,978
1858								
1859	369	Services						
1860			S		1,322,062,144	419,840,973	1,230,184,285	419,840,973
1861				B8	1,322,062,144	419,840,973	1,230,184,285	419,840,973
1862								
1863	370	Meters						
1864			S		379,606,965	119,080,187	361,167,574	119,080,187
1865				B8	379,606,965	119,080,187	361,167,574	119,080,187
1866								
1867	371	Installations on Customers' Premises						
1868			S		10,449,580	2,960,208	9,868,857	2,960,208
1869				B8	10,449,580	2,960,208	9,868,857	2,960,208
1870								
1871	372	Leased Property						
1872			S		-	-	-	-
1873				B8	-	-	-	-
1874								
1875	373	Street Lights						
1876			S		78,531,350	26,922,926	74,227,879	26,922,926
1877				B8	78,531,350	26,922,926	74,227,879	26,922,926
1878								
1879	DP	Unclassified Dist Plant - Acct 300						
1880			S		317,938,278	122,182,731	310,448,379	122,182,731
1881				B8	317,938,278	122,182,731	310,448,379	122,182,731
1882								
1883	DS0	Unclassified Dist Sub Plant - Acct 300						
1884			S		-	-	-	-
1885				B8	-	-	-	-
1886								
1887								
1888	**Total Distribution Plant**			**B8**	**11,952,888,109**	**3,377,916,256**	**11,203,888,010**	**3,378,666,277**
1889								
1890	Summary of Distribution Plant by Factor							
1891		S			11,904,355,007	3,365,009,636	11,155,354,908	3,365,009,636
1892		CN			10,802,634	3,255,887	10,802,634	3,496,051
1893		SNPD			37,730,467	9,650,733	37,730,467	10,160,590
1894								
1895	Total Distribution Plant by Factor				11,952,888,109	3,377,916,256	11,203,888,010	3,378,666,277
1896	389	Land and Land Rights						
1897			S		19,106,578	9,084,974	18,007,752	9,084,974
1898			CN		1,128,506	340,129	1,128,506	365,218
1899			SG		-	-	-	-
1900			SG		1,560	433	1,560	467
1901			SO		7,611,617	2,124,318	7,611,617	2,284,768
1902				B8	27,848,261	11,549,854	26,749,435	11,735,428
1903								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
1904	390	Structures and Improvements						
1905			S		151,673,623	44,496,575	137,171,687	44,496,575
1906			SG		-	-	-	-
1907			SG		-	-	-	-
1908			CN		8,218,829	2,477,134	8,218,829	2,659,855
1909			SG		12,023,520	3,337,197	11,978,785	3,588,306
1910			SE		940,953	252,390	940,953	270,538
1911			SO		117,070,442	32,673,063	117,070,442	35,140,870
1912				B8	289,927,366	83,236,359	275,380,695	86,156,144
1913								
1914	391	Office Furniture & Equipment						
1915			S		2,786,446	1,045,284	2,740,022	1,045,284
1916			SG		-	-	-	-
1917			SG		-	-	-	-
1918			CN		307,766	92,760	307,766	99,602
1919			SG		1,999,273	554,910	1,943,111	582,069
1920			SE		3,822	1,025	3,822	1,099
1921			SO		16,378,196	4,570,973	16,378,196	4,916,220
1922			SG		-	-	-	-
1923			SG		-	-	-	-
1924				B8	21,475,503	6,264,952	21,372,917	6,644,274
1925								
1926	392	Transportation Equipment						
1927			S		112,148,624	27,547,977	105,798,929	27,547,977
1928			SO		6,322,053	1,764,415	6,322,053	1,897,682
1929			SG		24,622,473	6,834,109	24,352,625	7,294,953
1930			CN		-	-	-	-
1931			SG		-	-	-	-
1932			SE		159,837	42,873	159,837	45,955
1933			SG		-	-	-	-
1934			SG		-	-	-	-
1935			SG		-	-	-	-
1936				B8	143,252,987	36,189,374	136,633,444	36,786,568
1937								
1938	393	Stores Equipment						
1939			S		11,913,385	3,974,550	10,883,335	3,974,550
1940			SG		-	-	-	-
1941			SG		-	-	-	-
1942			SO		283,479	79,116	283,479	85,092
1943			SG		7,815,837	2,169,330	7,601,099	2,276,948
1944			SG		-	-	-	-
1945				B8	20,012,702	6,222,996	18,767,913	6,336,589
1946								
1947	394	Tools, Shop & Garage Equipment						
1948			S		37,339,318	10,470,028	34,473,826	10,470,028
1949			SG		-	-	-	-
1950			SG		22,430,751	6,225,784	21,988,439	6,586,749
1951			SO		1,603,787	447,599	1,603,787	481,406
1952			SE		125,691	33,714	125,691	36,138
1953			SG		-	-	-	-
1954			SG		-	-	-	-
1955			SG		-	-	-	-
1956				B8	61,499,547	17,177,125	58,191,743	17,574,322
1957								
1958	395	Laboratory Equipment						
1959			S		27,574,505	10,534,808	26,129,650	10,534,808
1960			SG		-	-	-	-
1961			SG		-	-	-	-
1962			SO		4,436,256	1,238,110	4,436,256	1,331,625
1963			SE		1,225,288	328,656	1,225,288	352,288
1964			SG		5,904,754	1,638,898	5,789,957	1,734,411
1965			SG		-	-	-	-
1966			SG		-	-	-	-
1967				B8	39,140,803	13,740,472	37,581,152	13,953,132
1968								
1969	396	Power Operated Equipment						
1970			S		176,107,144	49,430,917	165,485,954	49,430,917
1971			SG		-	-	-	-
1972			SG		32,063,214	8,899,329	32,063,214	9,604,700
1973			SO		5,683,753	1,586,273	5,683,753	1,706,084
1974			SG		-	-	-	-
1975			SE		74,794	20,062	74,794	21,504
1976			SG		-	-	-	-
1977			SG		-	-	-	-
1978				B8	213,928,905	59,936,580	203,307,715	60,763,205

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
1979	397	Communication Equipment						
1980			S		20,590,122	(2,706,709)	21,119,003	(2,706,709)
1981			SG		-	-	-	-
1982			SG		-	-	-	-
1983			SO		619,584,453	172,919,153	619,584,453	185,979,792
1984			CN		227,354,102	68,523,954	227,354,102	73,578,491
1985			SG		(7,338,285)	(2,036,783)	(7,422,211)	(2,223,361)
1986			SE		10,433	2,798	10,433	3,000
1987			SG		-	-	-	-
1988			SG		-	-	-	-
1989				B8	860,200,825	236,702,412	860,645,780	254,631,213
1990								
1991	398	Misc. Equipment						
1992			S		3,788,640	1,379,092	3,579,036	1,379,092
1993			SG		-	-	-	-
1994			SG		-	-	-	-
1995			CN		80,053	24,128	80,053	25,907
1996			SO		3,657,984	1,020,903	3,657,984	1,098,012
1997			SE		3,966	1,064	3,966	1,140
1998			SG		2,944,157	817,168	2,936,803	879,734
1999			SG		-	-	-	-
2000				B8	10,474,800	3,242,354	10,257,841	3,383,886
2001								
2002	399	Coal Mine						
2003			SE		39,748,016	10,661,525	39,748,016	11,428,138
2004	MP		SE		-	-	-	-
2005				B8	39,748,016	10,661,525	39,748,016	11,428,138
2006								
2007	399L	WIDCO Capital Lease						
2008			SE		-	-	-	-
2009					-	-	-	-
2010								
2011		Remove Capital Leases			-	-	-	-
2012					-	-	-	-
2013								
2014	1011390	General Capital Leases						
2015			S		22,285,718	7,816,249	20,016,428	7,816,249
2016			SG		6,235,401	1,730,671	6,235,401	1,867,846
2017			SO		-	-	-	-
2018				B9	28,521,120	9,546,920	26,251,829	9,684,095
2019								
2020		Remove Capital Leases			(28,521,120)	(9,546,920)	(26,251,829)	(9,684,095)
2021					-	-	-	-
2022								
2023	1011346	General Gas Line Capital Leases						
2024			SG		-	-	-	-
2025				B9	-	-	-	-
2026								
2027		Remove Capital Leases			-	-	-	-
2028					-	-	-	-
2029								
2030	GP	Unclassified Gen Plant - Acct 300						
2031			S		-	-	-	-
2032			SO		198,333,670	55,352,729	198,333,670	59,533,538
2033			CN		-	-	-	-
2034			SG		-	-	-	-
2035			SG		-	-	-	-
2036			SG		-	-	-	-
2037				B8	198,333,670	55,352,729	198,333,670	59,533,538
2038								
2039	399G	Unclassified Gen Plant - Acct 300						
2040			S		-	-	-	-
2041			SO		-	-	-	-
2042			SG		-	-	-	-
2043			SG		-	-	-	-
2044			SG		-	-	-	-
2045				B8	-	-	-	-
2046								
2047	**Total General Plant**			**B8**	**1,925,843,384**	**540,276,733**	**1,886,970,320**	**568,926,436**
2048								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
2049	Summary of General Plant by Factor							
2050		S			585,314,105	163,073,744	545,405,621	163,073,744
2051		DGP			-	-	-	-
2052		DGU			-	-	-	-
2053		SG			108,702,655	30,171,047	107,468,784	32,192,823
2054		SO			980,965,690	273,776,650	980,965,690	294,455,089
2055		SE			42,292,799	11,344,107	42,292,799	12,159,800
2056		CN			237,089,255	71,458,104	237,089,255	76,729,074
2057		DEU			-	-	-	-
2058		SSGCT			-	-	-	-
2059		SSGCH			-	-	-	-
2060		Less Capital Leases			(28,521,120)	(9,546,920)	(26,251,829)	(9,684,095)
2061	Total General Plant by Factor				1,925,843,384	540,276,733	1,886,970,320	568,926,436
2062	301	Organization						
2063			S		-	-	-	-
2064			SO		-	-	-	-
2065			SG		-	-	-	-
2066				B8	-	-	-	-
2067	302	Franchise & Consent						
2068			S		1,000,000	-	1,000,000	-
2069			SG		24,512,823	6,803,675	23,028,398	6,898,274
2070			SG		103,455,075	28,714,551	103,455,075	30,990,496
2071			SG		10,195,370	2,829,784	10,195,370	3,054,075
2072			SG		-	-	-	-
2073			SG		-	-	-	-
2074				B8	139,163,268	38,348,009	137,678,843	40,942,846
2075								
2076	303	Miscellaneous Intangible Plant						
2077			S		23,001,523	4,597,089	20,985,453	4,597,089
2078			SG		171,644,833	47,641,010	153,513,501	45,985,754
2079			SO		(13,908,637)	(3,881,746)	(13,908,637)	(4,174,936)
2080			SE		-	-	-	-
2081			CN		(3,178,870)	(958,104)	(3,178,870)	(1,028,776)
2082			SG		-	-	-	-
2083			SG		-	-	-	-
2084				B8	177,558,849	47,398,249	157,411,447	45,379,130
2085	303	Less Non-Regulated Plant						
2086			S		-	-	-	-
2087					177,558,849	47,398,249	157,411,447	45,379,130
2088	IP	Unclassified Intangible Plant - Acct 300						
2089			S		-	-	-	-
2090			SG		-	-	-	-
2091			SG		-	-	-	-
2092			SO		-	-	-	-
2093					-	-	-	-
2094								
2095	**Total Intangible Plant**			**B8**	**316,722,118**	**85,746,258**	**295,090,290**	**86,321,976**
2096								
2097	Summary of Intangible Plant by Factor							
2098		S			24,001,523	4,597,089	21,985,453	4,597,089
2099		DGP			-	-	-	-
2100		DGU			-	-	-	-
2101		SG			309,808,102	85,989,019	290,192,345	86,928,599
2102		SO			(13,908,637)	(3,881,746)	(13,908,637)	(4,174,936)
2103		CN			(3,178,870)	(958,104)	(3,178,870)	(1,028,776)
2104		SSGCT			-	-	-	-
2105		SSGCH			-	-	-	-
2106		SE			-	-	-	-
2107	Total Intangible Plant by Factor				316,722,118	85,746,258	295,090,290	86,321,976
2108	Summary of Unclassified Plant (Account 106)							
2109		DP			317,938,278	122,182,731	310,448,379	122,182,731
2110		DS0			-	-	-	-
2111		GP			198,333,670	55,352,729	198,333,670	59,533,538
2112		HP			-	-	-	-
2113		NP			-	-	-	-
2114		OP			-	-	-	-
2115		TP			691,399,059	191,901,782	677,297,117	202,887,812
2116		TS0			-	-	-	-
2117		IP			-	-	-	-
2118		MP			-	-	-	-
2119		SP			176,015,597	48,854,140	176,015,597	52,726,371
2120	Total Unclassified Plant by Factor				1,383,686,604	418,291,382	1,362,094,763	437,330,452
2121								
2122	**Total Electric Plant In Service**			**B8**	**42,016,634,369**	**11,726,376,909**	**40,036,913,335**	**12,017,823,879**

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
2123	Summary of Electric Plant by Factor							
2124		S			12,515,148,326	3,533,599,673	11,724,223,673	3,533,599,673
2125		SE			42,292,799	11,344,107	42,292,799	12,159,800
2126		DGU			-	-	-	-
2127		DGP			-	-	-	-
2128		SG			28,238,213,825	7,837,678,525	27,047,148,153	8,102,111,409
2129		SO			967,057,053	269,894,904	967,057,053	290,280,153
2130		CN			244,713,019	73,755,887	244,713,019	79,196,349
2131		DEU			-	-	-	-
2132		SNPD			37,730,467	9,650,733	37,730,467	10,160,590
2133		SSGCT			-	-	-	-
2134		Less Capital Leases			(28,521,120)	(9,546,920)	(26,251,829)	(9,684,095)
2135					42,016,634,369	11,726,376,909	40,036,913,335	12,017,823,879
2136	105	Plant Held For Future Use						
2137			S		-	-	-	-
2138			SG		-	-	-	-
2139			SG		-	-	-	-
2140			SG		-	-	-	-
2141			SE		-	-	-	-
2142			SG		-	-	-	-
2143								
2144								
2145	**Total Plant Held For Future Use**			**B10**	**-**	**-**	**-**	**-**
2146								
2147	114	Electric Plant Acquisition Adjustments						
2148			S		11,763,784	-	11,763,784	-
2149			SG		144,704,699	40,163,621	144,704,699	43,347,032
2150			SG		-	-	-	-
2151	**Total Electric Plant Acquisition Adjustment**			**B15**	**156,468,483**	**40,163,621**	**156,468,483**	**43,347,032**
2152								
2153	115	Accum Provision for Asset Acquisition Adjustments						
2154			S		(3,104,083)	-	(3,104,083)	-
2155			SG		(142,239,555)	(39,479,406)	(142,239,555)	(42,608,585)
2156			SG		-	-	-	-
2157				B15	(145,343,638)	(39,479,406)	(145,343,638)	(42,608,585)
2158								
2159	128	Pensions						
2160			SO		-	-	-	-
2161	**Total Pensions**			**B15**	**-**	**-**	**-**	**-**
2162								
2163	124	Weatherization						
2164			S		465,169	-	461,857	-
2165			SO		-	-	-	-
2166				B16	465,169	-	461,857	-
2167								
2168	182W	Weatherization						
2169			S		350,035,460	-	350,035,460	-
2170			SG		-	-	-	-
2171			SGCT		-	-	-	-
2172			SO		-	-	-	-
2173				B16	350,035,460	-	350,035,460	-
2174								
2175	186W	Weatherization						
2176			S		-	-	-	-
2177			CN		-	-	-	-
2178			CNP		-	-	-	-
2179			SG		-	-	-	-
2180			SO		-	-	-	-
2181				B16	-	-	-	-
2182								
2183	**Total Weatherization**			**B16**	**350,500,629**	**-**	**350,497,317**	**-**
2184								
2185	151	Fuel Stock						
2186			DEU		-	-	-	-
2187			SE		347,164,314	93,119,143	347,164,314	99,814,833
2188			SE		-	-	-	-
2189			SE		-	-	-	-
2190				B13	347,164,314	93,119,143	347,164,314	99,814,833
2191								
2192	152	Fuel Stock - Undistributed						
2193			SE		-	-	-	-
2194					-	-	-	-
2195								
2196	25316	UAMPS Working Capital Deposit						
2197			SE		(6,559,077)	(1,759,327)	(6,559,077)	(1,885,831)
2198				B13	(6,559,077)	(1,759,327)	(6,559,077)	(1,885,831)
2199								
2200	25317	DG&T Working Capital Deposit						
2201			SE		(5,684,852)	(1,524,836)	(5,684,852)	(1,634,478)
2202				B13	(5,684,852)	(1,524,836)	(5,684,852)	(1,634,478)
2203								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
2204	25319	Provo Working Capital Deposit						
2205			SE		-	-	-	-
2206					-	-	-	-
2207								
2208	**Total Fuel Stock**			**B13**	**334,920,385**	**89,834,980**	**334,920,385**	**96,294,524**
2209	154	Materials and Supplies						
2210			S		439,887,578	196,859,862	408,408,356	196,859,862
2211			SG		159,383,503	44,237,807	154,919,175	46,406,830
2212			SE		-	-	-	-
2213			SO		(2,775,992)	(774,749)	(2,775,992)	(833,266)
2214			SG		-	-	-	-
2215			SG		-	-	-	-
2216			SNPD		(1,618,347)	(413,942)	(1,618,347)	(435,811)
2217			SG		-	-	-	-
2218			SG		-	-	-	-
2219			SG		-	-	-	-
2220			SG		-	-	-	-
2221			SG		-	-	-	-
2222			SG		-	-	-	-
2223				B13	594,876,742	239,908,978	558,933,191	241,997,615
2224								
2225	158	WA GHG Allocation Inventory						
2226			S		76,629,359	-	76,629,359	-
2227								
2228				B13	76,629,359	-	76,629,359	-
2229								
2230	25318	Provo Working Capital Deposit						
2231			SG		-	-	-	-
2232								
2233				B13	-	-	-	-
2234								
2235	**Total Materials and Supplies**			**B13**	**671,506,101**	**239,908,978**	**635,562,549**	**241,997,615**
2236								
2237	165	Prepayments						
2238			S		13,818,775	6,166,939	13,818,775	6,166,939
2239			GPS		80,059	22,360	80,059	24,038
2240			SG		6,660,844	1,848,756	6,660,844	1,995,290
2241			SE		(88,954)	(23,860)	(88,954)	(25,576)
2242			SO		154,231,659	43,044,346	154,231,659	46,295,500
2243	**Total Prepayments**			**B15**	**174,702,384**	**51,058,541**	**174,702,384**	**54,456,191**
2244								
2245	182M	Misc Regulatory Assets						
2246			S		1,330,203,065	-	1,339,464,687	-
2247			SG		(0)	(0)	(0)	(0)
2248			SGCT		-	-	-	-
2249			SG-P		-	-	-	-
2250			SE		82,931,611	22,244,569	82,931,611	23,844,055
2251			SG		-	-	-	-
2252			SO		116,709,610	32,572,358	116,709,610	35,032,559
2253				B16	1,529,844,286	54,816,928	1,539,105,908	58,876,614
2254								
2255	186M	Misc Deferred Debits						
2256			S		6,599,943	-	6,599,943	-
2257			SG		-	-	-	-
2258			SG		-	-	-	-
2259			SG		136,270,370	37,822,624	105,765,391	31,682,563
2260			SO		1,006,304	280,848	1,006,304	302,061
2261			SE		306,510	82,215	306,510	88,126
2262			SG		-	-	-	-
2263			EXCTAX		-	-	-	-
2264	**Total Misc. Deferred Debits**			**B11**	**144,183,127**	**38,185,687**	**113,678,148**	**32,072,750**
2265								
2266	Working Capital							
2267	CWC	Cash Working Capital						
2268			S		64,396,835	36,514,128	62,211,727	36,789,573
2269			SO		-	-	-	-
2270			SE		-	-	-	-
2271				B14	64,396,835	36,514,128	62,211,727	36,789,573
2272								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
2273	OWC	Other Work. Cap.						
2274	131	Cash	SNP		-	-	-	-
2275	135	Working Funds	SG		-	-	-	-
2276	141	Notes Receivable	SO		-	-	-	-
2277	143	Other A/R	SO		154,209,947	43,038,287	154,209,947	46,288,983
2278	232	A/P	S		(256,969)	-	(256,969)	-
2279	232	A/P	SO		(7,452,820)	(2,079,999)	(7,452,820)	(2,237,102)
2280	232	A/P	SE		(7,451,576)	(1,998,720)	(7,451,576)	(2,142,437)
2281	232	A/P	SG		(4,704,205)	(1,305,679)	(4,704,205)	(1,409,168)
2282	2533	Other Msc. Df. Crd.	S		-	-	-	-
2283	2533	Other Msc. Df. Crd.	SE		(9,849,796)	(2,641,990)	(9,849,796)	(2,831,961)
2284	2533	Other Msc. Df. Crd.	SO		-	-	-	-
2285	253	Other Msc. Df. Crd.	SE		-	-	-	-
2286	230	Asset Retir. Oblig.	SG		-	-	-	-
2287	230	Asset Retir. Oblig.	S		(2,032,458)	-	(2,032,458)	-
2288	254	Decom. Reg Liability	SG		(32,435,550)	(9,002,673)	(55,023,997)	(16,482,720)
2289	254	Reclam. Reg Liability	SE		-	-	-	-
2290	2533	Cholla Reclamation	SE		-	-	-	-
2291				B14	90,026,575	26,009,225	67,438,127	21,185,594
2292								
2293	**Total Working Capital**			**B14**	**154,423,410**	**62,523,353**	**129,649,855**	**57,975,167**
2294	Miscellaneous Rate Base							
2295	18221	Unrec Plant & Reg Study Costs						
2296			S		-	-	-	-
2297								
2298					-	-	-	-
2299								
2300	18222	Nuclear Plant - Trojan						
2301			S		-	-	-	-
2302			TROJP		-	-	-	-
2303			TROJD		-	-	-	-
2304				B16	-	-	-	-
2305								
2306								
2307								
2308	1869	Misc Deferred Debits						
2309			S		(14,356,267)	(14,356,267)	(14,356,267)	(14,356,267)
2310			SG		-	-	-	-
2311					(14,356,267)	(14,356,267)	(14,356,267)	(14,356,267)
2312								
2313	**Total Miscellaneous Rate Base**			**B15**	**(14,356,267)**	**(14,356,267)**	**(14,356,267)**	**(14,356,267)**
2314								
2315	**Total Rate Base Additions**				**3,356,848,899**	**522,656,415**	**3,274,885,125**	**528,055,042**
2316	235	Customer Service Deposits						
2317			S		-	-	-	-
2318			CN		-	-	-	-
2319	**Total Customer Service Deposits**			B15	**-**	**-**	**-**	**-**
2320								
2321	2281	Prop Ins	S		718,959	48,747,812	986,501	48,747,812
2322	2282	Inj & Dam	SO		-	-	-	-
2323	2283	Pen & Ben	SO		(753,363)	(210,255)	(753,363)	(226,136)
2324	2282	Prov for Injuries & Dam	S		506,680,000	3,443,229	506,680,000	3,443,229
2325	2281	Prop Ins	SO		-	-	-	-
2326	25335	Reg Liabilities	SE		(79,856,959)	(21,419,862)	(79,856,959)	(22,960,047)
2327				B15	426,788,637	30,560,924	427,056,179	29,004,858
2328								
2329	22841	Accum Misc. Operating Provisions						
2330			S		-	-	-	-
2331			SG		(234,889)	(65,195)	-	-
2332				B15	(234,889)	(65,195)	-	-
2333								
2334	254105	ARO	S		-	-	-	-
2335	230	ARO	TROJD		(7,998,127)	(2,206,591)	(7,998,127)	(2,378,667)
2336	254	Reg Liabilities	SO		(51,542,521)	(14,384,946)	(51,542,521)	(15,471,446)
2337	254		S		(1,275,948,568)	(302,351,746)	(1,193,822,192)	(303,704,047)
2338				B15	(1,335,489,217)	(318,943,284)	(1,253,362,841)	(321,554,160)
2339								
2340	252	Customer Advances for Construction						
2341			S		(50,727,686)	(10,054,115)	(49,983,723)	(10,054,115)
2342			SE		-	-	-	-
2343			SG		(282,304,129)	(78,355,133)	(282,304,129)	(84,565,644)
2344			SO		-	-	-	-
2345			CN		-	-	-	-
2346	**Total Customer Advances for Construction**			**B20**	**(333,031,816)**	**(88,409,248)**	**(332,287,853)**	**(94,619,759)**
2347								
2348	25398	SO2 Emissions						
2349			SE		-	-	-	-
2350					-	-	-	-
2351								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
2352	25399	Other Deferred Credits						
2353			S		149,643	(149,453)	420,996	(149,453)
2354			SO		(51,614,757)	(14,405,106)	(51,614,757)	(15,493,129)
2355			SG		(186,295,559)	(51,707,403)	(186,295,559)	(55,805,786)
2356			SE		(1,059,601)	(284,215)	(1,059,601)	(304,651)
2357				B15	(238,820,274)	(66,546,177)	(238,548,921)	(71,753,019)
2358								
2359	190	Accumulated Deferred Income Taxes						
2360			S		321,399,581	61,529,569	300,078,029	62,776,400
2361			CN		-	-	-	-
2362			SO		62,923,221	17,561,174	63,080,623	18,934,822
2363			DGP		-	-	-	-
2364			IBT		-	-	-	-
2365			SG		-	-	-	-
2366			SG		-	-	-	-
2367			BADDEBT		5,371,150	2,294,589	5,450,538	2,728,926
2368			TROJD		1,207,691	333,188	1,225,541	364,480
2369			SG		9,182,705	2,548,712	14,895,642	4,462,066
2370			SE		5,676,441	1,522,580	5,760,341	1,656,183
2371			SNP		-	-	-	-
2372			SNPD		3,154,869	806,955	3,201,500	862,145
2373			SG		-	-	-	-
2374				B19	408,915,659	86,596,767	393,692,214	91,785,020
2375								
2376	281	Accumulated Deferred Income Taxes						
2377			S		-	-	-	-
2378			SG		-	-	-	-
2379			SG		-	-	-	-
2380				B19	-	-	-	-
2381								
2382	282	Accumulated Deferred Income Taxes						
2383			S		(550,296,152)	(83,200,282)	(525,038,844)	(84,430,016)
2384			DITBAL		15	4	15	4
2385			SNP		(427,751)	(113,596)	(434,073)	(123,332)
2386			SO		(107,861,492)	(30,102,947)	(102,156,943)	(30,664,306)
2387			GPS		-	-	-	-
2388			CIAC		-	-	-	-
2389			SNPD		-	-	-	-
2390			SCHMDEXP		-	-	-	-
2391			TAXDEPR		-	-	-	-
2392			SG		-	-	-	-
2393			IBT		-	-	-	-
2394			SG		-	-	-	-
2395			CN		-	-	-	-
2396			SE		(273,957)	(73,483)	(278,006)	(79,931)
2397			SG		(2,658,038,905)	(737,753,973)	(2,492,818,142)	(746,736,410)
2398				B19	(3,316,898,242)	(851,244,277)	(3,120,725,992)	(862,033,991)
2399								
2400	283	Accumulated Deferred Income Taxes						
2401			S		(225,225,136)	(1,516,241)	(230,875,682)	(1,538,651)
2402			SG		(1,270,249)	(352,565)	(1,289,024)	(386,134)
2403			SE		(1,439,677)	(386,161)	(1,460,956)	(420,046)
2404			SO		(32,000,508)	(8,930,987)	(32,473,489)	(9,747,521)
2405			GPS		(7,486,718)	(2,091,007)	(7,597,375)	(2,281,167)
2406			SNP		(369,850)	(98,219)	(375,317)	(106,638)
2407			TROJD		-	-	-	-
2408			SG		-	-	-	-
2409			SG		-	-	-	-
2410			SG		-	-	-	-
2411				B19	(267,792,138)	(13,375,181)	(274,071,842)	(14,480,157)
2412								
2413	**Total Accum Deferred Income Tax**			**B19**	**(3,175,774,720)**	**(778,022,691)**	**(3,001,105,620)**	**(784,729,128)**
2414	255	Accumulated Investment Tax Credit						
2415			S		(469,238)	-	(469,238)	-
2416			ITC84		-	-	-	-
2417			ITC85		-	-	-	-
2418			ITC86		-	-	-	-
2419			ITC88		-	-	-	-
2420			ITC89		-	-	-	-
2421			ITC90		-	-	-	-
2422			SG		(93,723)	(26,013)	(93,723)	(28,075)
2423	**Total Accumulated ITC**			**B19**	**(562,961)**	**(26,013)**	**(562,961)**	**(28,075)**
2424								
2425	**Total Rate Base Deductions**				**(4,657,125,239)**	**(1,221,451,684)**	**(4,398,812,016)**	**(1,243,679,283)**
2426								
2427								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
2428								
2429	108SP	Steam Prod Plant Accumulated Depr						
2430			S		(125,633,865)	-	(109,570,593)	-
2431			SG		-	-	-	-
2432			SG		-	-	-	-
2433			SG		(6,049,553,958)	(1,679,088,466)	(6,117,450,481)	(1,832,513,545)
2434			SG		-	-	-	-
2435			SG		-	-	-	-
2436				B17	(6,175,187,822)	(1,679,088,466)	(6,227,021,074)	(1,832,513,545)
2437								
2438	108NP	Nuclear Prod Plant Accumulated Depr						
2439			SG		-	-	-	-
2440			SG		-	-	-	-
2441			SG		-	-	-	-
2442				B17	-	-	-	-
2443								
2444								
2445	108HP	Hydraulic Prod Plant Accum Depr						
2446			S		-	-	-	-
2447			SG		-	-	-	-
2448			SG		-	-	-	-
2449			SG		(415,929,560)	(115,443,640)	(415,929,560)	(124,593,825)
2450			SG		(140,832,124)	(39,088,765)	(140,832,124)	(42,186,982)
2451			SG		(17,893,097)	(4,966,332)	(17,893,097)	(5,359,969)
2452				B17	(574,654,781)	(159,498,737)	(574,654,781)	(172,140,775)
2453								
2454	108XP	Solar Prod Plant Accum Depr						
2455			S		(383,257)	(250,088)	(383,257)	(250,088)
2456			SG		(67,257)	(18,667)	(67,257)	(20,147)
2457				B17	(450,514)	(268,755)	(450,514)	(270,235)
2458								
2459	108WP	Wind Prod Plant Accum Depr						
2460			S		(149,452,701)	(149,452,701)	(149,452,701)	(149,452,701)
2461			SG		(515,040,842)	(142,952,545)	(524,793,838)	(157,204,675)
2462				B17	(664,493,543)	(292,405,247)	(674,246,539)	(306,657,376)
2463								
2464	108RP	Other Renewable Prod Plant Accum Depr						
2465			S		-	-	-	-
2466			SG		(107,717,078)	(29,897,494)	(107,717,078)	(32,267,201)
2467				B17	(107,717,078)	(29,897,494)	(107,717,078)	(32,267,201)
2468								
2469	108OP	Other Production Plant - Accum Depr						
2470			S		-	-	-	-
2471			SG		-	-	-	-
2472			SG		-	-	-	-
2473			SG		(833,460,220)	(231,331,674)	(643,360,500)	(192,721,925)
2474			SG		-	-	-	-
2475				B17	(833,460,220)	(231,331,674)	(643,360,500)	(192,721,925)
2476								
2477	108EP	Experimental Plant - Accum Depr						
2478			SG		-	-	-	-
2479			SG		-	-	-	-
2480					-	-	-	-
2481								
2482	**Total Production Plant Accum Depreciation**			**B17**	**(8,355,963,959)**	**(2,392,490,373)**	**(8,227,450,486)**	**(2,536,571,057)**
2483								
2484	Summary of Prod Plant Depreciation by Factor							
2485			S		(275,469,823)	(149,702,789)	(259,406,552)	(149,702,789)
2486			DGP		-	-	-	-
2487			DGU		-	-	-	-
2488			SG		(8,080,494,136)	(2,242,787,584)	(7,968,043,935)	(2,386,868,268)
2489			SSGCH		-	-	-	-
2490			SSGCT		-	-	-	-
2491	Total of Prod Plant Depreciation by Factor				(8,355,963,959)	(2,392,490,373)	(8,227,450,486)	(2,536,571,057)
2492								
2493								
2494	108TP	Transmission Plant Accumulated Depr						
2495			S		0	0	0	0
2496			SG		-	-	-	-
2497			SG		-	-	-	-
2498			SG		(2,986,638,199)	(828,958,596)	(2,902,464,888)	(869,448,185)
2499	**Total Trans Plant Accum Depreciation**			**B17**	**(2,986,638,199)**	**(828,958,596)**	**(2,902,464,888)**	**(869,448,185)**
2500	108360	Land and Land Rights						
2501			S		(14,522,244)	(3,371,639)	(14,047,556)	(3,371,639)
2502				B17	(14,522,244)	(3,371,639)	(14,047,556)	(3,371,639)
2503								
2504	108361	Structures and Improvements						
2505			S		(47,182,559)	(12,260,514)	(44,812,441)	(12,260,514)
2506				B17	(47,182,559)	(12,260,514)	(44,812,441)	(12,260,514)
2507								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
2508	108362	Station Equipment						
2509			S		(461,964,960)	(126,265,511)	(425,349,917)	(126,265,511)
2510				B17	(461,964,960)	(126,265,511)	(425,349,917)	(126,265,511)
2511								
2512	108363	Storage Battery Equipment						
2513			S		(84,393,922)	(29,839,846)	(79,207,898)	(29,839,846)
2514			CN		(10,802,634)	(3,255,887)	(10,802,634)	(3,496,051)
2515			SNPD		(31,082,684)	(7,950,357)	(31,082,684)	(8,370,381)
2516				B17	(126,279,240)	(41,046,090)	(121,093,216)	(41,706,278)
2517								
2518	108364	Poles, Towers & Fixtures						
2519			S		(844,907,597)	(302,470,250)	(752,093,299)	(302,470,250)
2520				B17	(844,907,597)	(302,470,250)	(752,093,299)	(302,470,250)
2521								
2522	108365	Overhead Conductors						
2523			S		(431,653,913)	(161,143,458)	(385,213,515)	(161,143,458)
2524				B17	(431,653,913)	(161,143,458)	(385,213,515)	(161,143,458)
2525								
2526	108366	Underground Conduit						
2527			S		(227,196,137)	(59,920,607)	(212,456,453)	(59,920,607)
2528				B17	(227,196,137)	(59,920,607)	(212,456,453)	(59,920,607)
2529								
2530	108367	Underground Conductors						
2531			S		(488,346,613)	(121,112,830)	(468,206,494)	(121,112,830)
2532				B17	(488,346,613)	(121,112,830)	(468,206,494)	(121,112,830)
2533								
2534	108368	Line Transformers						
2535			S		(741,768,530)	(289,615,432)	(663,968,750)	(289,615,432)
2536				B17	(741,768,530)	(289,615,432)	(663,968,750)	(289,615,432)
2537								
2538	108369	Services						
2539			S		(478,468,871)	(178,846,843)	(435,831,569)	(178,846,843)
2540				B17	(478,468,871)	(178,846,843)	(435,831,569)	(178,846,843)
2541								
2542	108370	Meters						
2543			S		(147,354,150)	(46,256,795)	(135,994,659)	(46,256,795)
2544				B17	(147,354,150)	(46,256,795)	(135,994,659)	(46,256,795)
2545								
2546								
2547								
2548	108371	Installations on Customers' Premises						
2549			S		(7,665,504)	(2,200,269)	(7,208,576)	(2,200,269)
2550				B17	(7,665,504)	(2,200,269)	(7,208,576)	(2,200,269)
2551								
2552	108372	Leased Property						
2553			S		-	-	-	-
2554				B17	-	-	-	-
2555								
2556	108373	Street Lights						
2557			S		(36,502,578)	(12,993,031)	(34,565,953)	(12,993,031)
2558				B17	(36,502,578)	(12,993,031)	(34,565,953)	(12,993,031)
2559								
2560	108D00	Unclassified Dist Plant - Acct 300						
2561			S		-	-	-	-
2562				B17	-	-	-	-
2563								
2564	108DS	Unclassified Dist Sub Plant - Acct 300						
2565			S		-	-	-	-
2566				B17	-	-	-	-
2567								
2568	108DP	Unclassified Dist Sub Plant - Acct 300						
2569			S		5,633,788	1,460,620	5,340,046	1,460,620
2570				B17	5,633,788	1,460,620	5,340,046	1,460,620
2571								
2572								
2573	**Total Distribution Plant Accum Depreciation**			**B17**	**(4,048,179,107)**	**(1,356,042,651)**	**(3,695,502,351)**	**(1,356,702,839)**
2574								
2575	Summary of Distribution Plant Depr by Factor							
2576		S			(4,006,293,789)	(1,344,836,407)	(3,653,617,033)	(1,344,836,407)
2577								
2578	Total Distribution Depreciation by Factor				(4,006,293,789)	(1,344,836,407)	(3,653,617,033)	(1,344,836,407)
2579	108GP	General Plant Accumulated Depr						
2580			S		(262,678,824)	(68,620,248)	(241,329,225)	(68,620,248)
2581			SG		165,454	45,923	165,454	49,562
2582			SG		513,009	142,389	513,009	153,675
2583			SG		(60,300,157)	(16,736,655)	(59,592,307)	(17,851,180)
2584			CN		(222,176,030)	(66,963,296)	(222,176,030)	(71,902,715)
2585			SO		(596,683,846)	(166,527,847)	(596,683,846)	(179,105,749)
2586			SE		(1,561,399)	(418,811)	(1,561,399)	(448,925)
2587			SG		-	-	-	-
2588			SG		-	-	-	-
2589				B17	(1,142,721,792)	(319,078,546)	(1,120,664,343)	(337,725,581)

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT OREGON
2590								
2591								
2592	108MP	Mining Plant Accumulated Depr.						
2593			S		-	-	-	-
2594			SE		-	-	-	-
2595				B17	-	-	-	-
2596	108MP	Less Centralia Situs Depreciation						
2597			S		-	-	-	-
2598				B17	-	-	-	-
2599								
2600	1081390	Accum Depr - Capital Lease						
2601			SO	B17	-	-	-	-
2602					-	-	-	-
2603								
2604		Remove Capital Leases			-	-	-	-
2605				B17	-	-	-	-
2606								
2607	1081399	Accum Depr - Capital Lease						
2608			S		-	-	-	-
2609			SE	B17	-	-	-	-
2610					-	-	-	-
2611								
2612		Remove Capital Leases			-	-	-	-
2613				B17	-	-	-	-
2614								
2615								
2616	**Total General Plant Accum Depreciation**			**B17**	**(1,142,721,792)**	**(319,078,546)**	**(1,120,664,343)**	**(337,725,581)**
2617								
2618								
2619								
2620	Summary of General Depreciation by Factor							
2621		S			(262,678,824)	(68,620,248)	(241,329,225)	(68,620,248)
2622		DGP			-	-	-	-
2623		DGU			-	-	-	-
2624		SE			(1,561,399)	(418,811)	(1,561,399)	(448,925)
2625		SO			(596,683,846)	(166,527,847)	(596,683,846)	(179,105,749)
2626		CN			(222,176,030)	(66,963,296)	(222,176,030)	(71,902,715)
2627		SG			(59,621,694)	(16,548,344)	(58,913,844)	(17,647,943)
2628		DEU			-	-	-	-
2629		SSGCT			-	-	-	-
2630		SSGCH			-	-	-	-
2631		Remove Capital Leases			-	-	-	-
2632	Total General Depreciation by Factor				(1,142,721,792)	(319,078,546)	(1,120,664,343)	(337,725,581)
2633								
2634								
2635	**Total Accum Depreciation - Plant In Service**			**B17**	**(16,533,503,057)**	**(4,896,570,165)**	**(15,946,082,068)**	**(5,100,447,662)**
2636	111OP	Accum Prov for Amort-Other						
2637			S		-	-	-	-
2638			SG		-	-	-	-
2639				B18	-	-	-	-
2640								
2641								
2642	111GP	Accum Prov for Amort-General						
2643			S		(13,495,928)	(5,403,828)	(11,028,204)	(5,403,828)
2644			CN		-	-	-	-
2645			SG		-	-	-	-
2646			SO		(1,943,674)	(542,458)	(1,943,674)	(583,430)
2647			SE		-	-	-	-
2648				B18	(15,439,603)	(5,946,286)	(12,971,879)	(5,987,258)
2649								
2650								
2651	111HP	Accum Prov for Amort-Hydro						
2652			SG		-	-	-	-
2653			SG		-	-	-	-
2654			SG		(5,023,251)	(1,394,232)	(5,023,251)	(1,504,741)
2655			SG		-	-	-	-
2656				B18	(5,023,251)	(1,394,232)	(5,023,251)	(1,504,741)
2657								
2658								
2659	111XP	Accum Prov for Amort-Solar						
2660			S		(279,419)	(279,419)	(279,419)	(279,419)
2661			SG		-	-	-	-
2662				B18	(279,419)	(279,419)	(279,419)	(279,419)
2663								
2664	111WP	Accum Prov for Amort-Wind						
2665			S		-	-	-	-
2666			SG		-	-	-	-
2667				B18	-	-	-	-
2668								

	2020 PROTOCOL 13-Month Average FERC ACCT	DESCRIP	FACTOR	Ref	DECEMBER 2027 NORMALIZED RESULTS_Pre-SAT TOTAL	 OREGON	DECEMBER 2027 NORMALIZED RESULTS_Post-SAT TOTAL	 OREGON
2669	111RP	Accum Prov for Amort-Other Renewable						
2670			S		-	-	-	-
2671			SG		-	-	-	-
2672				B18	-	-	-	-
2673								
2674	111IP	Accum Prov for Amort-Intangible Plant						
2675			S		(2,120,862)	(170,171)	(2,126,037)	(170,171)
2676			SG		-	-	-	-
2677			SG		18,570	5,154	18,570	5,563
2678			SE		-	-	-	-
2679			SG		(88,082,469)	(24,447,795)	(77,762,304)	(23,294,095)
2680			SG		(56,588,688)	(15,706,515)	(56,588,688)	(16,951,430)
2681			SG		(7,595,160)	(2,108,080)	(7,595,160)	(2,275,169)
2682			CN		3,178,870	958,104	3,178,870	1,028,776
2683			SG		-	-	-	-
2684			SG		-	-	-	-
2685			SO		13,908,637	3,881,746	13,908,637	4,174,936
2686				B18	(137,281,100)	(37,587,557)	(126,966,110)	(37,481,590)
2687	111IP	Less Non-Regulated Plant						
2688			OTH		-	-	-	-
2689					(137,281,100)	(37,587,557)	(126,966,110)	(37,481,590)
2690								
2691	111390	Accum Amtr - Capital Lease						
2692			S		-	-	-	-
2693			SG		-	-	-	-
2694			SO		-	-	-	-
2695				B9	-	-	-	-
2696								
2697		Remove Capital Lease Amtr			-	-	-	-
2698								
2699	**Total Accum Provision for Amortization**			**B18**	**(158,023,373)**	**(45,207,495)**	**(145,240,659)**	**(45,253,009)**
2700								
2701								
2702								
2703								
2704	Summary of Amortization by Factor							
2705		S			(15,896,209)	(5,853,418)	(13,433,660)	(5,853,418)
2706		DGP			-	-	-	-
2707		DGU			-	-	-	-
2708		SE			-	-	-	-
2709		SO			11,964,963	3,339,288	11,964,963	3,591,506
2710		CN			3,178,870	958,104	3,178,870	1,028,776
2711		SSGCT			-	-	-	-
2712		SSGCH			-	-	-	-
2713		SG			(157,270,997)	(43,651,469)	(146,950,833)	(44,019,873)
2714		Less Capital Lease			-	-	-	-
2715	Total Provision For Amortization by Factor				(158,023,373)	(45,207,495)	(145,240,659)	(45,253,009)

Tab 3 - Post-Service Area Transfer Adjustments

Adjustments WA_1 to WA_5 are reflected in the Jurisdictional Allocation Model supporting the Post-Service Area Transfer revenue requirement calculation only. No separate lead sheet is provided under this section.

PacifiCorp Page WA_6
Oregon General Rate Case - December 2027
Generation Resources Removal for Washington Sales

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Intangible Plant	303	3	(15,473,732)	SG	29.956%	(4,635,235)	
Other Production	340	3	(3,730,527)	SG	29.956%	(1,117,498)	
Other Production	341	3	(24,673,334)	SG	29.956%	(7,391,023)	
Other Production	342	3	(1,597,346)	SG	29.956%	(478,493)	
Other Production	343	3	(222,357,377)	SG	29.956%	(66,608,288)	
Other Production	344	3	(76,413,210)	SG	29.956%	(22,889,967)	
Other Production	345	3	(39,277,504)	SG	29.956%	(11,765,777)	
Other Production	346	3	(3,268,830)	SG	29.956%	(979,195)	
Transmission	351	3	(85,891)	SG	29.956%	(25,729)	
Transmission	352	3	(2,926,697)	SG	29.956%	(876,707)	
Transmission	353	3	(33,037,006)	SG	29.956%	(9,896,404)	
Transmission	355	3	(1,775,330)	SG	29.956%	(531,809)	
Transmission	356	3	(1,740,133)	SG	29.956%	(521,266)	
General Plant	391	3	(56,162)	SG	29.956%	(16,824)	
General Plant	392	3	(269,848)	SG	29.956%	(80,834)	
General Plant	393	3	(214,738)	SG	29.956%	(64,326)	
General Plant	394	3	(442,311)	SG	29.956%	(132,497)	
General Plant	395	3	(93,317)	SG	29.956%	(27,954)	
General Plant	397	3	(83,926)	SG	29.956%	(25,140)	
General Plant	398	3	(7,355)	SG	29.956%	(2,203)	
Wind Generation	338WP	3	(482,075,451)	SG	29.956%	(144,408,164)	
			(909,600,024)			(272,475,334)	WA_6.2
Other Production	108OP	3	190,099,720	SG	29.956%	56,945,342	
Wind Generation	108WP	3	(9,752,996)	SG	29.956%	(2,921,560)	
Transmission	108TP	3	11,713,429	SG	29.956%	3,508,817	
General Plant	108GP	3	561,141	SG	29.956%	168,093	
Intangible Plant	111IP	3	9,345,141	SG	29.956%	2,799,385	
			201,966,435			60,500,077	WA_6.2
Misc. Rate Base	186M	3	(39,814,887)	SG	29.956%	(11,926,753)	
Misc. Rate Base	22841	3	234,889	SG	29.956%	70,362	
			(39,579,999)			(11,856,391)	WA_6.3

Description of Adjustment

This adjustment removes rate base and expenses associated with specific generation resources that are expected to be transferred in the Washington service territory sales transaction.

PacifiCorp Page WA_6.1
Oregon General Rate Case - December 2027
Generation Resources Removal for Washington Sales

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Operation - Other Prod.	546	3	(220,628)	SG	29.956%	(66,090)	
Operation - Other Prod.	548	3	(2,770,397)	SG	29.956%	(829,887)	
Operation - Other Prod.	549	3	(1,638,982)	SG	29.956%	(490,966)	
Maintenance - Other Prod.	552	3	(86,929)	SG	29.956%	(26,040)	
Maintenance - Other Prod.	553	3	(2,619,819)	SG	29.956%	(784,780)	
Other Power Supply	557	3	(168,266)	SG	29.956%	(50,405)	
Operation - Other Prod.	550	3	(1,040,970)	SG	29.956%	(311,828)	
Maintenance - Other Prod.	554	3	(84,553)	SG	29.956%	(25,328)	
Operation - Wind Prod.	558WP	3	(4,726,751)	SG	29.956%	(1,415,922)	
Maintenance - Trans.	570	3	(105,321)	SG	29.956%	(31,550)	
Maintenance - Trans.	571	3	(2,575)	SG	29.956%	(771)	
Maintenance - Trans.	572	3	(119,177)	SG	29.956%	(35,700)	
			(13,584,370)			(4,069,268)	WA_6.3
Depreciation - Other Prod.	403OP	3	(13,028,730)	SG	29.956%	(3,902,823)	
Depreciation - Wind Prod.	403WP	3	(19,240,599)	SG	29.956%	(5,763,620)	
Depreciation - Transmission	403TP	3	(700,327)	SG	29.956%	(209,786)	
Depreciation - General	403GP	3	(30,195)	SG	29.956%	(9,045)	
Amortization - Intangible	404IP	3	(433,993)	SG	29.956%	(130,005)	
			(33,433,844)			(10,015,279)	WA_6.2

Description of Adjustment

This adjustment removes rate base and expenses associated with specific generation resources that are expected to be transferred in the Washington service territory sales transaction.

PacifiCorp
Oregon General Rate Case - December 2027
Generation Resources Removal for Washington Sales
Summary of Balances by FERC Account - Plant In-Service & Depreciation

Electric Plant In-Service

FERC	Factor	Chehalis	Goodnoe Hills	Marengo	Adjustment
303	SG	15,373,721	100,011	-	(15,473,732)
340	SG	3,730,527	-	-	(3,730,527)
341	SG	24,673,334	-	-	(24,673,334)
342	SG	1,597,346	-	-	(1,597,346)
343	SG	222,357,377	-	-	(222,357,377)
344	SG	76,413,210	-	-	(76,413,210)
345	SG	39,277,504	-	-	(39,277,504)
346	SG	3,268,830	-	-	(3,268,830)
351	SG	-	-	85,891	(85,891)
352	SG	-	1,132,551	1,794,145	(2,926,697)
353	SG	12,522,798	8,816,206	11,698,002	(33,037,006)
355	SG	-	-	1,775,330	(1,775,330)
356	SG	-	-	1,740,133	(1,740,133)
391	SG	49,453	3,662	3,047	(56,162)
392	SG	33,505	80,029	156,314	(269,848)
393	SG	115,040	29,930	69,768	(214,738)
394	SG	434,499	6,608	1,205	(442,311)
395	SG	92,287	1,030	-	(93,317)
397	SG	83,926	-	-	(83,926)
398	SG	7,355	-	-	(7,355)
338WP	SG	-	156,531,286	325,544,165	(482,075,451)
TOTAL		400,030,712	166,701,313	342,867,999	**(909,600,024)**

Ref WA_6

Accumulated Depreciation Reserve

FERC	Factor	Chehalis	Goodnoe Hills	Marengo	Adjustment
108OP	SG	(190,099,720)	-	-	190,099,720
108WP	SG	-	12,223,814	(2,470,818)	(9,752,996)
108TP	SG	(3,215,625)	(2,947,609)	(5,550,195)	11,713,429
108GP	SG	(366,793)	(80,757)	(113,591)	561,141
111IP	SG	(9,320,635)	(24,506)	-	9,345,141
TOTAL		(203,002,773)	9,170,942	(8,134,604)	**201,966,435**

Ref WA_6

Depreciation Expense

FERC	Factor	Chehalis	Goodnoe Hills	Marengo	Adjustment
403OP	SG	13,028,730	-	-	(13,028,730)
403WP	SG	-	6,247,469	12,993,129	(19,240,599)
403TP	SG	221,662	176,099	302,566	(700,327)
403GP	SG	21,103	3,136	5,956	(30,195)
404IP	SG	431,188	2,805	-	(433,993)
TOTAL		13,702,683	6,429,509	13,301,652	**(33,433,844)**

Ref WA_6.1

PacifiCorp Page WA_6.3
Oregon General Rate Case - December 2027
Generation Resources Removal for Washington Sales
Summary of Balances by FERC Account - Other Rate Base & OMAG

Other Rate Base

FERC	Factor	Chehalis	Goodnoe Hills	Marengo	Adjustment
186M	SG	24,388,953	4,471,062	10,954,873	(39,814,887)
22841	SG	(234,889)	-	-	234,889
TOTAL		24,154,064	4,471,062	10,954,873	**(39,579,999)**

Ref WA_6

Operations & Maintenance Expense

FERC	Factor	Chehalis	Goodnoe Hills	Marengo	Adjustment
546	SG	220,628	-	-	(220,628)
548	SG	2,770,397	-	-	(2,770,397)
549	SG	824,219	714,648	100,116	(1,638,982)
552	SG	86,929	-	-	(86,929)
557	SG	168,266	-	-	(168,266)
550	SG	-	209,504	831,465	(1,040,970)
553	SG	1,109,577	-	1,510,242	(2,619,819)
554	SG	-	41,008	43,545	(84,553)
558WP	SG	-	1,331,828	3,394,923	(4,726,751)
570	SG	-	70,412	34,910	(105,321)
571	SG	-	1,506	1,069	(2,575)
572	SG	-	626	118,551	(119,177)
TOTAL		5,180,017	2,369,532	6,034,821	**(13,584,370)**

Ref WA_6.1

PacifiCorp
Oregon General Rate Case - December 2027
Chehalis Plant Balances Removal
Net Plant In-Service & Depreciation Expense

FERC	Factor	EOP June 2025	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Mo. Avg
340	SG	3,730,527	3,730,527	3,730,527	3,730,527	3,730,527	3,730,527	3,730,527	3,730,527	3,730,527	3,730,527	3,730,527	3,730,527	3,730,527	3,730,527	3,730,527
341	SG	24,673,334	24,673,334	24,673,334	24,673,334	24,673,334	24,673,334	24,673,334	24,673,334	24,673,334	24,673,334	24,673,334	24,673,334	24,673,334	24,673,334	24,673,334
342	SG	1,597,346	1,597,346	1,597,346	1,597,346	1,597,346	1,597,346	1,597,346	1,597,346	1,597,346	1,597,346	1,597,346	1,597,346	1,597,346	1,597,346	1,597,346
343	SG	220,606,032	222,291,152	222,317,240	222,343,329	222,369,418	222,369,418	222,369,418	222,369,418	222,369,418	222,369,418	222,369,418	222,369,418	222,369,418	222,369,418	222,357,377
344	SG	76,413,210	76,413,210	76,413,210	76,413,210	76,413,210	76,413,210	76,413,210	76,413,210	76,413,210	76,413,210	76,413,210	76,413,210	76,413,210	76,413,210	76,413,210
345	SG	39,277,504	39,277,504	39,277,504	39,277,504	39,277,504	39,277,504	39,277,504	39,277,504	39,277,504	39,277,504	39,277,504	39,277,504	39,277,504	39,277,504	39,277,504
346	SG	3,268,830	3,268,830	3,268,830	3,268,830	3,268,830	3,268,830	3,268,830	3,268,830	3,268,830	3,268,830	3,268,830	3,268,830	3,268,830	3,268,830	3,268,830
353	SG	12,522,798	12,522,798	12,522,798	12,522,798	12,522,798	12,522,798	12,522,798	12,522,798	12,522,798	12,522,798	12,522,798	12,522,798	12,522,798	12,522,798	12,522,798
391	SG	49,453	49,453	49,453	49,453	49,453	49,453	49,453	49,453	49,453	49,453	49,453	49,453	49,453	49,453	49,453
392	SG	33,505	33,505	33,505	33,505	33,505	33,505	33,505	33,505	33,505	33,505	33,505	33,505	33,505	33,505	33,505
393	SG	115,040	115,040	115,040	115,040	115,040	115,040	115,040	115,040	115,040	115,040	115,040	115,040	115,040	115,040	115,040
394	SG	434,499	434,499	434,499	434,499	434,499	434,499	434,499	434,499	434,499	434,499	434,499	434,499	434,499	434,499	434,499
395	SG	92,287	92,287	92,287	92,287	92,287	92,287	92,287	92,287	92,287	92,287	92,287	92,287	92,287	92,287	92,287
397	SG	83,926	83,926	83,926	83,926	83,926	83,926	83,926	83,926	83,926	83,926	83,926	83,926	83,926	83,926	83,926
398	SG	7,355	7,355	7,355	7,355	7,355	7,355	7,355	7,355	7,355	7,355	7,355	7,355	7,355	7,355	7,355
303	SG	15,373,721	15,373,721	15,373,721	15,373,721	15,373,721	15,373,721	15,373,721	15,373,721	15,373,721	15,373,721	15,373,721	15,373,721	15,373,721	15,373,721	15,373,721
																400,030,712
																Ref WA_6.2
108OP	SG	(164,093,659)	(183,585,485)	(184,671,051)	(185,756,692)	(186,842,410)	(187,928,167)	(189,013,923)	(190,099,679)	(191,185,435)	(192,271,191)	(193,356,947)	(194,442,703)	(195,528,459)	(196,614,216)	(190,099,720)
108TP	SG	(2,772,302)	(3,104,794)	(3,123,266)	(3,141,738)	(3,160,209)	(3,178,681)	(3,197,153)	(3,215,625)	(3,234,097)	(3,252,568)	(3,271,040)	(3,289,512)	(3,307,984)	(3,326,456)	(3,215,625)
108GP	SG	(324,587)	(356,242)	(358,000)	(359,759)	(361,517)	(363,276)	(365,035)	(366,793)	(368,552)	(370,310)	(372,069)	(373,828)	(375,586)	(377,345)	(366,793)
111IP	SG	(8,458,259)	(9,105,041)	(9,140,974)	(9,176,906)	(9,212,838)	(9,248,771)	(9,284,703)	(9,320,635)	(9,356,568)	(9,392,500)	(9,428,432)	(9,464,365)	(9,500,297)	(9,536,230)	(9,320,635)
																(203,002,773)
																Ref WA_6.2
																12 ME Dec-27
403OP	SG		1,085,490	1,085,565	1,085,642	1,085,718	1,085,756	1,085,756	1,085,756	1,085,756	1,085,756	1,085,756	1,085,756	1,085,756	1,085,756	13,028,730
403TP	SG		18,472	18,472	18,472	18,472	18,472	18,472	18,472	18,472	18,472	18,472	18,472	18,472	18,472	221,662
403GP	SG		1,759	1,759	1,759	1,759	1,759	1,759	1,759	1,759	1,759	1,759	1,759	1,759	1,759	21,103
404IP	SG		35,932	35,932	35,932	35,932	35,932	35,932	35,932	35,932	35,932	35,932	35,932	35,932	35,932	431,188
																13,702,683
																Ref WA_6.2

Composite Depreciation Rates:

Other Production:	3.509%
Transmission:	1.770%
General Plant:	2.586%
Intangible:	2.805%

PacifiCorp Page WA_6.5
Oregon General Rate Case - December 2027
Chehalis Plant Balances Removal
Non-EPIS Rate Base Balances & OMAG Removal

FERC	Factor	EOP June 2025	
186M	SG	24,388,953	[1]
22841	SG	(234,889)	

FERC	Factor	12 ME June 2025	IHS Escalation	12 ME December 2027
546	SG	210,487	4.82%	220,628
548	SG	2,643,062	4.82%	2,770,397
549	SG	786,335	4.82%	824,219
552	SG	82,905	4.85%	86,929
553	SG	1,058,209	4.85%	1,109,577
557	SG	160,532	4.82%	168,266
				5,180,017

Ref WA_6.3

1. Pro forma adjustments to FERC 186M will be reversed through separate adjustment

PacifiCorp
Oregon General Rate Case - December 2027
Goodnoe Hills Wind Plant Balances Removal
Net Plant In-Service & Depreciation Expense

FERC	Factor	EOP June 2025	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Mo. Avg
338WP	SG	155,387,859	156,401,183	156,401,183	156,401,183	156,570,317	156,570,317	156,570,317	156,570,317	156,570,317	156,570,317	156,570,317	156,570,317	156,570,317	156,570,317	156,531,286
352	SG	1,132,551	1,132,551	1,132,551	1,132,551	1,132,551	1,132,551	1,132,551	1,132,551	1,132,551	1,132,551	1,132,551	1,132,551	1,132,551	1,132,551	1,132,551
353	SG	8,816,206	8,816,206	8,816,206	8,816,206	8,816,206	8,816,206	8,816,206	8,816,206	8,816,206	8,816,206	8,816,206	8,816,206	8,816,206	8,816,206	8,816,206
391	SG	3,662	3,662	3,662	3,662	3,662	3,662	3,662	3,662	3,662	3,662	3,662	3,662	3,662	3,662	3,662
392	SG	80,029	80,029	80,029	80,029	80,029	80,029	80,029	80,029	80,029	80,029	80,029	80,029	80,029	80,029	80,029
393	SG	29,930	29,930	29,930	29,930	29,930	29,930	29,930	29,930	29,930	29,930	29,930	29,930	29,930	29,930	29,930
394	SG	6,608	6,608	6,608	6,608	6,608	6,608	6,608	6,608	6,608	6,608	6,608	6,608	6,608	6,608	6,608
395	SG	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030
303	SG	100,011	100,011	100,011	100,011	100,011	100,011	100,011	100,011	100,011	100,011	100,011	100,011	100,011	100,011	100,011
																166,701,313
																Ref WA_6.2
108WP	SG	24,678,082	15,347,040	14,826,863	14,306,686	13,786,227	13,265,488	12,744,748	12,224,008	11,703,269	11,182,529	10,661,789	10,141,050	9,620,310	9,099,571	12,223,814
108TP	SG	(2,595,410)	(2,859,559)	(2,874,234)	(2,888,909)	(2,903,584)	(2,918,259)	(2,932,934)	(2,947,609)	(2,962,284)	(2,976,959)	(2,991,634)	(3,006,309)	(3,020,984)	(3,035,659)	(2,947,609)
108GP	SG	(74,486)	(79,189)	(79,450)	(79,712)	(79,973)	(80,234)	(80,496)	(80,757)	(81,018)	(81,280)	(81,541)	(81,802)	(82,064)	(82,325)	(80,757)
111IP	SG	(18,896)	(23,103)	(23,337)	(23,571)	(23,804)	(24,038)	(24,272)	(24,506)	(24,739)	(24,973)	(25,207)	(25,441)	(25,674)	(25,908)	(24,506)
																9,170,942
																Ref WA_6.2
																12 ME Dec-27
403WP	SG		519,925	520,177	520,177	520,458	520,740	520,740	520,740	520,740	520,740	520,740	520,740	520,740	520,740	6,247,469
403TP	SG		14,675	14,675	14,675	14,675	14,675	14,675	14,675	14,675	14,675	14,675	14,675	14,675	14,675	176,099
403GP	SG		261	261	261	261	261	261	261	261	261	261	261	261	261	3,136
404IP	SG		234	234	234	234	234	234	234	234	234	234	234	234	234	2,805
																6,429,509
																Ref WA_6.2

Composite Depreciation Rates:

Other Production:	3.991%
Transmission:	1.770%
General Plant:	2.586%
Intangible:	2.805%

PacifiCorp
Oregon General Rate Case - December 2027
Goodnoe Hill Wind Plant Balances Removal
Non-EPIS Rate Base Balances & OMAG

FERC	Factor	12 ME December 2027
186M	SG	4,471,062

FERC	Factor	12 ME June 2025	IHS Escalation	12 ME December 2027
549	SG	681,800	4.82%	714,648
550	SG	199,875	4.82%	209,504
554	SG	39,110	4.85%	41,008
558WP	SG	1,270,614	4.82%	1,331,828
570	SG	67,483	4.34%	70,412
571	SG	1,443	4.34%	1,506
572	SG	600	4.34%	626
				2,369,532

Ref WA_6.3

PacifiCorp
Oregon General Rate Case - December 2027
Marengo Wind Plant Balances Removal
Net Plant In-Service & Depreciation Expense

FERC	Factor	EOP June 2025	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Mo. Avg
338WP	SG	322,977,241	325,251,432	325,251,432	325,251,432	325,631,985	325,631,985	325,631,985	325,631,985	325,631,985	325,631,985	325,631,985	325,631,985	325,631,985	325,631,985	325,544,165
351	SG	85,891	85,891	85,891	85,891	85,891	85,891	85,891	85,891	85,891	85,891	85,891	85,891	85,891	85,891	85,891
352	SG	1,794,145	1,794,145	1,794,145	1,794,145	1,794,145	1,794,145	1,794,145	1,794,145	1,794,145	1,794,145	1,794,145	1,794,145	1,794,145	1,794,145	1,794,145
353	SG	11,698,002	11,698,002	11,698,002	11,698,002	11,698,002	11,698,002	11,698,002	11,698,002	11,698,002	11,698,002	11,698,002	11,698,002	11,698,002	11,698,002	11,698,002
355	SG	1,775,330	1,775,330	1,775,330	1,775,330	1,775,330	1,775,330	1,775,330	1,775,330	1,775,330	1,775,330	1,775,330	1,775,330	1,775,330	1,775,330	1,775,330
356	SG	1,740,133	1,740,133	1,740,133	1,740,133	1,740,133	1,740,133	1,740,133	1,740,133	1,740,133	1,740,133	1,740,133	1,740,133	1,740,133	1,740,133	1,740,133
391	SG	3,047	3,047	3,047	3,047	3,047	3,047	3,047	3,047	3,047	3,047	3,047	3,047	3,047	3,047	3,047
392	SG	156,314	156,314	156,314	156,314	156,314	156,314	156,314	156,314	156,314	156,314	156,314	156,314	156,314	156,314	156,314
393	SG	69,768	69,768	69,768	69,768	69,768	69,768	69,768	69,768	69,768	69,768	69,768	69,768	69,768	69,768	69,768
394	SG	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
																342,867,999
																Ref WA_6.2
108WP	SG	23,424,626	4,024,603	2,942,844	1,861,085	778,694	(304,331)	(1,387,355)	(2,470,380)	(3,553,404)	(4,636,429)	(5,719,453)	(6,802,478)	(7,885,502)	(8,968,526)	(2,470,818)
108TP	SG	(4,945,063)	(5,398,912)	(5,424,126)	(5,449,340)	(5,474,554)	(5,499,767)	(5,524,981)	(5,550,195)	(5,575,409)	(5,600,623)	(5,625,836)	(5,651,050)	(5,676,264)	(5,701,478)	(5,550,195)
108GP	SG	(101,678)	(110,613)	(111,109)	(111,605)	(112,102)	(112,598)	(113,094)	(113,591)	(114,087)	(114,583)	(115,080)	(115,576)	(116,072)	(116,569)	(113,591)
																(8,134,604)
																Ref WA_6.2
																12 ME Dec-27
403WP	SG		1,081,187	1,081,759	1,081,759	1,082,392	1,083,024	1,083,024	1,083,024	1,083,024	1,083,024	1,083,024	1,083,024	1,083,024	1,083,024	12,993,129
403TP	SG		25,214	25,214	25,214	25,214	25,214	25,214	25,214	25,214	25,214	25,214	25,214	25,214	25,214	302,566
403GP	SG		496	496	496	496	496	496	496	496	496	496	496	496	496	5,956
																13,301,652
																Ref WA_6.2

Composite Depreciation Rates:

Other Production:	3.991%
Transmission:	1.770%
General Plant:	2.586%

PacifiCorp Page WA_6.9
Oregon General Rate Case - December 2027
Marengo Plant Balances Removal
Non-EPIS Rate Base Balances & OMAG

FERC	Factor	12 ME December 2027
186M	SG	10,954,873

FERC	Factor	12 ME June 2025	IHS Escalation (PAC/1102)	12 ME December 2027
549	SG	95,514	4.82%	100,116
550	SG	793,249	4.82%	831,465
553	SG	1,440,324	4.85%	1,510,242
554	SG	41,529	4.85%	43,545
558WP	SG	3,238,882	4.82%	3,394,923
570	SG	33,458	4.34%	34,910
571	SG	1,025	4.34%	1,069
572	SG	113,621	4.34%	118,551
				6,034,821

Ref WA_6.3

PacifiCorp PAGE WA_7
Oregon General Rate Case - December 2027
Removal of Other Balances for Washington Sales

	ACCOUNT	Type	TOTAL COMPANY	2020P FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Transmission	350	3	(1,307,390)	SG	29.956%	(391,635)	
Transmission	350	3	(6,160,796)	SG	29.956%	(1,845,498)	
Transmission	351	3	(11,344,931)	SG	29.956%	(3,398,432)	
Transmission	352	3	(382,315)	SG	29.956%	(114,524)	
Transmission	352	3	(13,120,663)	SG	29.956%	(3,930,362)	
Transmission	353	3	(5,692,785)	SG	29.956%	(1,705,303)	
Transmission	353	3	(79,512,725)	SG	29.956%	(23,818,443)	
Transmission	354	3	(268,816)	SG	29.956%	(80,525)	
Transmission	354	3	(5,915,634)	SG	29.956%	(1,772,058)	
Transmission	355	3	(5,554,070)	SG	29.956%	(1,663,750)	
Transmission	355	3	(62,178,953)	SG	29.956%	(18,626,023)	
Transmission	356	3	(6,600,550)	SG	29.956%	(1,977,229)	
Transmission	356	3	(65,060,666)	SG	29.956%	(19,489,255)	
Transmission	357	3	(2,092)	SG	29.956%	(627)	
Transmission	359	3	(53,080)	SG	29.956%	(15,900)	
General	390	3	(20,396)	SG	29.956%	(6,110)	
General	390	3	(24,339)	SG	29.956%	(7,291)	
General	395	3	(21,479)	SG	29.956%	(6,434)	
Intangible	302	3	(1,484,425)	SG	29.956%	(444,667)	
Intangible	303	3	(2,657,600)	SG	29.956%	(796,098)	
Transmission	TP	3	(14,101,942)	SG	29.956%	(4,224,309)	
			(281,465,648)			(84,314,473)	WA_7.2
Transmission	108TP	3	17,887,744	SG	29.956%	5,358,365	
Transmission	108TP	3	55,450,053	SG	29.956%	16,610,347	
General Plant	108GP	3	23,373	SG	29.956%	7,002	
General Plant	108GP	3	123,336	SG	29.956%	36,946	
Intangible Plant	111IP	3	975,024	SG	29.956%	292,073	
			74,459,530			22,304,733	WA_7.2
Transmission	403TP	3	(734,285)	SG	29.956%	(219,959)	
Transmission	403TP	3	(4,605,982)	SG	29.956%	(1,379,745)	
General Plant	403GP	3	(307)	SG	29.956%	(92)	
General Plant	403GP	3	(1,712)	SG	29.956%	(513)	
Intangible Plant	404IP	3	(116,172)	SG	29.956%	(34,800)	
			(5,458,458)			(1,635,109)	WA_7.2

Description of Adjustment

This adjustment removes rate base and expenses associated with specific non-generation assets that are expected to be transferred in the Washington service area transfer transaction.

PacifiCorp PAGE WA_7.1
Oregon General Rate Case - December 2027
Removal of Other Balances for Washington Sales

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Materials & Supplies	154	3	(4,464,329)	SG	29.956%	(1,337,312)	WA_7.5
Adjustment to Expenses:							
Taxes Other Than Inc.	408	3	(18,675,905)	SO	30.017%	(5,605,920)	
Other Expenses	557	3	(113)	SG	29.956%	(34)	
Operation - Trans.	562	3	(91,012)	SG	29.956%	(27,263)	
Operation - Trans.	563	3	(115,292)	SG	29.956%	(34,536)	
Operation - Trans.	566	3	(42,678)	SG	29.956%	(12,784)	
Maintenance - Trans.	567	3	(81,703)	SG	29.956%	(24,475)	
Maintenance - Trans.	569	3	(50,088)	SG	29.956%	(15,004)	
Maintenance - Trans.	570	3	(591,590)	SG	29.956%	(177,214)	
Maintenance - Trans.	571	3	(1,516,898)	SG	29.956%	(454,395)	
Admin. & General	922	3	(1,727)	SO	30.017%	(518)	
Admin. & General	925	3	(11,503)	SO	30.017%	(3,453)	
Admin. & General	929	3	(57,681)	SO	30.017%	(17,314)	
			(21,236,190)			(6,372,910)	WA_7.5

Description of Adjustment

This adjustment removes rate base and expenses associated with specific non-generation assets that are expected to be transferred in the Washington service area transfer transaction.

PacifiCorp Page WA_7.2
Oregon General Rate Case - December 2027
Removal of Other Balances for Washington Sales
EPIS Rate Base Balances & Depreciation

Function	Factor	Gross Plant	Accum. Res.	Depr. Expense	
Transmission	SG	277,257,408	(73,337,797)	5,340,267	
General	SG	66,214	(146,709)	2,019	
Intangible	SG	4,142,025	(975,024)	116,172	
		281,465,648	**(74,459,530)**	**5,458,458**	**Ref WA_7**

PacifiCorp
Oregon General Rate Case - December 2027
Removal of Other Balances for Washington Sales
Net Plant In-Service & Depreciation Expense
Wallula & Walla Walla Substation Assets

FERC	2020 Protocol Factor	EOP June 2025	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Mo. Avg
350	SG	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441
350	SG	1,071,734	1,071,734	1,071,734	1,071,734	1,071,734	1,071,734	1,071,734	1,071,734	1,071,734	1,071,734	1,071,734	1,071,734	1,071,734	1,071,734	1,071,734
351	SG	1,659,711	1,659,711	1,659,711	1,659,711	1,659,711	1,659,711	1,659,711	1,659,711	1,659,711	1,659,711	1,659,711	1,659,711	1,659,711	1,659,711	1,659,711
352	SG	85,385	85,385	85,385	85,385	85,385	85,385	85,385	85,385	85,385	85,385	85,385	85,385	85,385	85,385	85,385
352	SG	2,422,809	2,422,809	2,422,809	2,422,809	2,422,809	2,422,809	2,422,809	2,422,809	2,422,809	2,422,809	2,422,809	2,422,809	2,422,809	2,422,809	2,422,809
353	SG	2,654,248	2,654,248	2,654,248	2,654,248	2,654,248	2,654,248	2,654,248	2,654,248	2,654,248	2,654,248	2,654,248	2,654,248	2,654,248	2,654,248	2,654,248
353	SG	13,184,294	13,184,294	13,184,294	13,184,294	13,184,294	13,184,294	13,184,294	13,184,294	13,184,294	13,184,294	13,184,294	13,184,294	13,184,294	13,184,294	13,184,294
354	SG	681,793	681,793	681,793	681,793	681,793	681,793	681,793	681,793	681,793	681,793	681,793	681,793	681,793	681,793	681,793
355	SG	1,647,384	1,647,384	1,647,384	1,647,384	1,647,384	1,647,384	1,647,384	1,647,384	1,647,384	1,647,384	1,647,384	1,647,384	1,647,384	1,647,384	1,647,384
356	SG	2,783,676	2,783,676	2,783,676	2,783,676	2,783,676	2,783,676	2,783,676	2,783,676	2,783,676	2,783,676	2,783,676	2,783,676	2,783,676	2,783,676	2,783,676
390	SG	20,396	20,396	20,396	20,396	20,396	20,396	20,396	20,396	20,396	20,396	20,396	20,396	20,396	20,396	20,396
390	SG	6,653	6,653	6,653	6,653	6,653	6,653	6,653	6,653	6,653	6,653	6,653	6,653	6,653	6,653	6,653
																26,242,524
108TP	SG	(1,630,324)	(2,297,828)	(2,334,912)	(2,371,995)	(2,409,079)	(2,446,162)	(2,483,246)	(2,520,329)	(2,557,413)	(2,594,497)	(2,631,580)	(2,668,664)	(2,705,747)	(2,742,831)	(2,520,329)
108TP	SG	(3,995,970)	(4,692,016)	(4,730,685)	(4,769,354)	(4,808,024)	(4,846,693)	(4,885,362)	(4,924,031)	(4,962,700)	(5,001,370)	(5,040,039)	(5,078,708)	(5,117,377)	(5,156,047)	(4,924,031)
108GP	SG	(22,760)	(23,220)	(23,245)	(23,271)	(23,297)	(23,322)	(23,348)	(23,373)	(23,399)	(23,424)	(23,450)	(23,476)	(23,501)	(23,527)	(23,373)
108GP	SG	(3,114)	(4,164)	(4,222)	(4,280)	(4,339)	(4,397)	(4,455)	(4,513)	(4,572)	(4,630)	(4,688)	(4,747)	(4,805)	(4,863)	(4,513)
																(7,472,247)
																12 ME Dec-27
403TP	SG		37,084	37,084	37,084	37,084	37,084	37,084	37,084	37,084	37,084	37,084	37,084	37,084	37,084	445,003
403TP	SG		38,669	38,669	38,669	38,669	38,669	38,669	38,669	38,669	38,669	38,669	38,669	38,669	38,669	464,031
403GP	SG		26	26	26	26	26	26	26	26	26	26	26	26	26	307
403GP	SG		58	58	58	58	58	58	58	58	58	58	58	58	58	699
																910,040

Composite Depreciation Rates:

Transmission (DGP):	1.697%
Transmission (SG):	1.770%
Distribution:	2.626%
General Plant (DGP):	1.134%
General Plant (SG):	2.586%

PacifiCorp
Oregon General Rate Case - December 2027
Removal of Other Balances for Washington Sales
Net Plant In-Service & Depreciation Expense
Other Locations

FERC	2020 Protocol Factor	EOP June 2025	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Mo. Avg
350	SG	1,282,950	1,282,950	1,282,950	1,282,950	1,282,950	1,282,950	1,282,950	1,282,950	1,282,950	1,282,950	1,282,950	1,282,950	1,282,950	1,282,950	1,282,950
350	SG	5,089,062	5,089,062	5,089,062	5,089,062	5,089,062	5,089,062	5,089,062	5,089,062	5,089,062	5,089,062	5,089,062	5,089,062	5,089,062	5,089,062	5,089,062
351	SG	9,685,220	9,685,220	9,685,220	9,685,220	9,685,220	9,685,220	9,685,220	9,685,220	9,685,220	9,685,220	9,685,220	9,685,220	9,685,220	9,685,220	9,685,220
352	SG	296,929	296,929	296,929	296,929	296,929	296,929	296,929	296,929	296,929	296,929	296,929	296,929	296,929	296,929	296,929
352	SG	10,697,853	10,697,853	10,697,853	10,697,853	10,697,853	10,697,853	10,697,853	10,697,853	10,697,853	10,697,853	10,697,853	10,697,853	10,697,853	10,697,853	10,697,853
353	SG	3,038,538	3,038,538	3,038,538	3,038,538	3,038,538	3,038,538	3,038,538	3,038,538	3,038,538	3,038,538	3,038,538	3,038,538	3,038,538	3,038,538	3,038,538
353	SG	66,328,432	66,328,432	66,328,432	66,328,432	66,328,432	66,328,432	66,328,432	66,328,432	66,328,432	66,328,432	66,328,432	66,328,432	66,328,432	66,328,432	66,328,432
354	SG	268,816	268,816	268,816	268,816	268,816	268,816	268,816	268,816	268,816	268,816	268,816	268,816	268,816	268,816	268,816
354	SG	5,233,840	5,233,840	5,233,840	5,233,840	5,233,840	5,233,840	5,233,840	5,233,840	5,233,840	5,233,840	5,233,840	5,233,840	5,233,840	5,233,840	5,233,840
355	SG	5,554,070	5,554,070	5,554,070	5,554,070	5,554,070	5,554,070	5,554,070	5,554,070	5,554,070	5,554,070	5,554,070	5,554,070	5,554,070	5,554,070	5,554,070
355	SG	60,531,569	60,531,569	60,531,569	60,531,569	60,531,569	60,531,569	60,531,569	60,531,569	60,531,569	60,531,569	60,531,569	60,531,569	60,531,569	60,531,569	60,531,569
356	SG	6,600,550	6,600,550	6,600,550	6,600,550	6,600,550	6,600,550	6,600,550	6,600,550	6,600,550	6,600,550	6,600,550	6,600,550	6,600,550	6,600,550	6,600,550
356	SG	62,276,990	62,276,990	62,276,990	62,276,990	62,276,990	62,276,990	62,276,990	62,276,990	62,276,990	62,276,990	62,276,990	62,276,990	62,276,990	62,276,990	62,276,990
357	SG	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092	2,092
359	SG	53,080	53,080	53,080	53,080	53,080	53,080	53,080	53,080	53,080	53,080	53,080	53,080	53,080	53,080	53,080
TP	SG	14,101,942	14,101,942	14,101,942	14,101,942	14,101,942	14,101,942	14,101,942	14,101,942	14,101,942	14,101,942	14,101,942	14,101,942	14,101,942	14,101,942	14,101,942
390	SG	17,686	17,686	17,686	17,686	17,686	17,686	17,686	17,686	17,686	17,686	17,686	17,686	17,686	17,686	17,686
395	SG	21,479	21,479	21,479	21,479	21,479	21,479	21,479	21,479	21,479	21,479	21,479	21,479	21,479	21,479	21,479
302	SG	1,484,425	1,484,425	1,484,425	1,484,425	1,484,425	1,484,425	1,484,425	1,484,425	1,484,425	1,484,425	1,484,425	1,484,425	1,484,425	1,484,425	1,484,425
303	SG	2,657,600	2,657,600	2,657,600	2,657,600	2,657,600	2,657,600	2,657,600	2,657,600	2,657,600	2,657,600	2,657,600	2,657,600	2,657,600	2,657,600	2,657,600
																255,223,124
108TP	SG	(42,242,119)	(48,455,046)	(48,800,209)	(49,145,371)	(49,490,534)	(49,835,697)	(50,180,859)	(50,526,022)	(50,871,184)	(51,216,347)	(51,561,510)	(51,906,672)	(52,251,835)	(52,596,997)	(50,526,022)
108TP	SG	(14,771,326)	(15,222,773)	(15,246,880)	(15,270,987)	(15,295,094)	(15,319,201)	(15,343,308)	(15,367,414)	(15,391,521)	(15,415,628)	(15,439,735)	(15,463,842)	(15,487,949)	(15,512,056)	(15,367,414)
108GP	SG	(116,797)	(118,316)	(118,400)	(118,485)	(118,569)	(118,654)	(118,738)	(118,822)	(118,907)	(118,991)	(119,076)	(119,160)	(119,245)	(119,329)	(118,822)
111IP	SG	(742,680)	(916,938)	(926,619)	(936,300)	(945,981)	(955,662)	(965,343)	(975,024)	(984,705)	(994,386)	(1,004,067)	(1,013,748)	(1,023,429)	(1,033,110)	(975,024)
																(66,987,282)
																12 ME Dec-27
403TP	SG		345,162.61	345,162.61	345,162.61	345,162.61	345,162.61	345,162.61	345,162.61	345,162.61	345,162.61	345,162.61	345,162.61	345,162.61	345,162.61	4,141,951
403TP	SG		24,106.85	24,106.85	24,106.85	24,106.85	24,106.85	24,106.85	24,106.85	24,106.85	24,106.85	24,106.85	24,106.85	24,106.85	24,106.85	289,282
403GP	SG		84.40	84.40	84.40	84.40	84.40	84.40	84.40	84.40	84.40	84.40	84.40	84.40	84.40	1,013
404IP	SG		9,680.98	9,680.98	9,680.98	9,680.98	9,680.98	9,680.98	9,680.98	9,680.98	9,680.98	9,680.98	9,680.98	9,680.98	9,680.98	116,172
																4,548,418

Composite Depreciation Rates:

Transmission (SG):	1.770%
Transmission (DGP):	1.697%
General Plant:	2.586%
Intangible:	2.805%

PacifiCorp Page WA_7.5
Oregon General Rate Case - December 2027
Removal of Other Balances for Washington Sales
Non-EPIS Rate Base Balances & OMAG

FERC	Factor	12 ME December 2027
154	SG	**4,464,329**
		Ref WA_7.1

FERC	Factor	12 ME June 2025	IHS Escalation	12 ME December 2027
408	SO	18,675,905	0.00%	18,675,905
557	SG	108	4.82%	113
562	SG	87,612	3.88%	91,012
563	SG	110,985	3.88%	115,292
566	SG	41,084	3.88%	42,678
567	SG	78,651	3.88%	81,703
569	SG	48,004	4.34%	50,088
570	SG	566,986	4.34%	591,590
571	SG	1,453,810	4.34%	1,516,898
922	SO	1,616	6.85%	1,727
925	SO	11,503	0.00%	11,503
929	SO	53,984	6.85%	57,681
				21,236,190
				Ref WA_7.1

PacifiCorp Page WA_8
Oregon General Rate Case - December 2027
Washington Wheeling Revenues

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Other Electric Revenues	456	3	23,913,389	SG	29.956%	7,163,378	WA_8.1

Description of Adjustment:

The company has reached an agreement with PGE to sell its Washington service territory and certain associated assets. This adjustment incorporates into the Test Period the revenues related to the transmission service PacifiCorp will provide as part of the transaction.

PacifiCorp Page WA_8.1
Oregon General Rate Case - December 2027
Washington Wheeling Revenues

Impacted Wheeling Revenues	**Annual Amount**
95MW Walla Walla to Wallula	5,109,890
95MW Wallula to Walla Walla	5,109,890
240/265MW from MIDC-Walla Walla	13,693,609
	23,913,389
	Ref WA_8

Pacificorp PAGE WA_9
Oregon General Rate Case - December 2027
Chehalis Overhaul Expense Removal

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Generation Overhaul Expense - Other	553	1	(974,015)	SG	29.956%	(291,771)	WA_9.1
			(974,015)				

Description of Adjustment:

The company has entered into an agreement with Portland General Electric (PGE) to sell its Washington service territory and certain related assets. To determine a normalized Test Period level of generation overhaul expense, the Company applies a four-year average methodology and restates the results in constant dollars. As part of this process, the unadjusted Chehalis overhaul expense is removed in Adjustment WA_6, leaving the portion of normalized expense remaining in the Test Period. This adjustment removes the remaining portion of the Chehalis generation overhaul expense from the Test Period.

Pacificorp PAGE WA_9.1
Oregon General Rate Case - December 2027
Chehalis Overhaul Expense Removal
Incremental Impact from Washington Sales

	ACCOUNT	Type	Adj. 4.6 TOTAL COMPANY	REVISED TOTAL COMPANY	Adjustment Change	
Adjustment to Expense:						
Generation Overhaul Expense - Other	553	1	(3,003,344)	(3,977,359)	(974,015)	WA_9
			(3,003,344)	(3,977,359)		
			Ref PAC/1002	Ref WA_9.2		

Pacificorp
Oregon General Rate Case - December 2027
Chehalis Overhaul Expense Removal
Without Chehalis

Existing Units	Yr. Ended June 2022	Yr. Ended June 2023	Yr. Ended June 2024	Yr. Ended June 2025	Ref.
Other Production					
Hermiston	703,300	3,330,569	1,258,340	475,564	PAC/1002
Currant Creek	2,093,766	288,991	121,485	623,880	PAC/1002
Lake Side	748,317	(397,541)	5,963,884	9,170,826	PAC/1002
Gadsby Peakers	-	-	-	-	PAC/1002
Chehalis	**-**	**-**	**-**	**-**	**Removed**
Total - Other Production	3,545,383	3,222,018	7,343,709	10,270,270	
Restate to Constant Dollars	11.79%	5.46%	2.68%	0.00%	PAC/802
Total Restated - Other Production	3,963,217	3,397,823	7,540,332	10,270,270	
4 Year Average - Restated Dollars				6,292,911	
12 Months Ended Jun 2025 Overhaul Expense - Other				10,270,270	Above
Adjustment				**(3,977,359)**	
				Ref WA_9.1	

PacifiCorp PAGE WA_10
Oregon General Rate Case - December 2027
Property Tax Expense Reduction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	408	3	(7,600,000)	GPS	30.0353%	(2,282,680)	WA_10.1

Description of Adjustment:

This adjustment reflects the change in property tax expense expected as a result of the Service Area Transfer.

Pacificorp PAGE WA_10.1
Oregon General Rate Case - December 2027
Property Tax Expense Reduction
Incremental Impact from Washington Sales

	ACCOUNT	Type	Adj. 7.2 TOTAL COMPANY	REVISED TOTAL COMPANY	Adjustment Change	REF#
Adjustment to Expense:						
Taxes Other Than Income	408	3	32,742,298	25,142,298	(7,600,000)	WA_10
			32,742,298	25,142,298		
			Ref PAC/802	Ref WA_10.2		

PacifiCorp PAGE WA_10.2
Oregon General Rate Case - December 2027
Property Tax Expense Reduction
Estimated Test Period Property Tax - Post-Service Area Transfer

FERC Account	G/L Account	Co. Code	Total	Ref
408.15	579000	1000	152,360,699	
Total Accrued Property Tax - 12 Months End. June 2025			152,360,699	
Estimated Property Tax Expense for 12 Months Ending December 31, 2027			177,502,997	

PacifiCorp PAGE WA_11
Oregon General Rate Case - December 2027
PowerTax Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
ADIT - Other	282	3	(15,936)	OTHER	0.000%	-	WA_11.1
ADIT - SG	282	3	184,119,713	SG	29.956%	55,154,001	WA_11.1
ADIT - SO	282	3	7,192,479	SO	30.017%	2,158,956	WA_11.1
			191,296,256				
DIT Expense - Flowthrough	41110	3	(208,257)	SG	29.956%	(62,385)	WA_11.1
DIT Expense - Flowthrough	41110	3	(19,443)	SO	30.017%	(5,836)	WA_11.1
			(227,701)				
Book Depreciation	SCHMAT	3	(38,894,185)	SCHMDEXP	29.342%	(11,412,392)	WA_11.1
Tax Depreciation	SCHMDT	3	(48,827,940)	TAXDEPR	29.685%	(14,494,664)	WA_11.1
Book Depreciation - DIT Expense	41110	3	9,562,758	SCHMDEXP	29.342%	2,805,919	WA_11.1
Tax Depreciation - DIT Expense	41010	3	(12,005,130)	TAXDEPR	29.685%	(3,563,745)	WA_11.1

Description of Adjustment:

The Company has reached an agreement with Portland General Electric (“PGE”) to sell its Washington service territory and certain associated assets. This removes the income tax impacts related to the assets sold to PGE.

PacifiCorp
Oregon General Rate Case - December 2027
PowerTax Adjustment

Book Tax Difference		Total Company			STATE Allocation	
Description - ADIT	**#**	**2020 Protocol**	**Remove WA**	**Adjusted Utility**	**2020 Protocol**	
Accumulated Deferred Income Taxes (CA)	**	(32,669,402)	0	(32,669,402)	CA	
Accumulated Deferred Income Taxes (IDU)	**	(35,877,448)	0	(35,877,448)	IDU	
Accumulated Deferred Income Taxes (OR)	**	(104,427,376)	0	(104,427,376)	OR	
Accumulated Deferred Income Taxes (OTHER)	**	737,957	(15,968)	721,989	OTHER	
Accumulated Deferred Income Taxes (UT)	**	(2,700,537,583)	0	(2,700,537,583)	UT	
Accumulated Deferred Income Taxes (WA)	**	(118,217,038)	44,026,886	(74,190,152)	WA	**
Accumulated Deferred Income Taxes (WY)	**	(349,187,765)	0	(349,187,765)	WYP	
Accumulated Deferred Income Taxes (SG)	**	(32,059,129)	**184,296,430**	152,237,301	SG	**Ref. WA_11**
Accumulated Deferred Income Taxes (SO)	**	(71,449,257)	**7,187,664**	(64,261,593)	SO	**Ref. WA_11**
Accumulated Deferred Income Taxes (DITBAL)	**	0	0	0	DITBAL	
Accelerated Pollution Control Facilities ADIT (SG) - FERC 281	**	0	0	0	SG	
		(3,443,687,041)	235,495,011	(3,208,192,030)		

Book Tax Difference		Total Company			STATE Allocation	
Description - Deferred Income Tax Expense	**#**	**2020 Protocol**	**Remove WA**	**Adjusted Utility**	**2020 Protocol**	
Flow-through:						
California	105.115	(130,069)	0	(130,069)	CA	
Idaho	105.115	(30,207)	0	(30,207)	IDU	
Oregon	105.115	(74)	0	(74)	OR	
OTHER	105.115	(1,279,010)	0	(1,279,010)	NREG	
Utah	105.115	5,910,457	0	5,910,457	UT	
Washington	105.115	711,614	(19,112)	692,502	WA	**
Wyoming - P	105.115	(2,280,702)	0	(2,280,702)	WYP	
SG	105.115	(9,043)	**(208,257)**	(217,301)	SG	**Ref. WA_11**
SO	105.115	(16,874)	**(19,443)**	(36,317)	SO	**Ref. WA_11**
Total		2,876,093	(246,813)	2,629,281		

Book Tax Difference		Total Company			STATE Allocation
Book Depreciation	**#**	**2020 Protocol**	**Remove WA**	**Adjusted Utility**	**2020 Protocol**
Book Depreciation Removed - Adj. WA_6	105.120		**(33,433,844)**		SCHMDEXP
Book Depreciation Removed - Adj. WA_7	105.120		**(5,460,341)**		SCHMDEXP
Total Book Depreciation removed		1,225,313,886	(38,894,185)	1,186,419,701	
			Ref. WA_11		

Book Tax Difference		Total Company			STATE Allocation
Tax Depreciation	**#**	**2020 Protocol**	**Remove WA**	**Adjusted Utility**	**2020 Protocol**
Tax Depreciation	105.120	(1,451,933,046)	**48,827,940**	(1,403,105,106)	TAXDEPR
			Ref. WA_11		

**Washington situs balances are removed through Adjustment WA_4/WA_5 in the Jurisdictional Allocation Model (JAM) supporting post-Service Area Transfer revenue requirement calculation

PacifiCorp PAGE WA_12
Oregon General Rate Case - December 2027
Pro Forma Tax Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
DIT Expense - Tax Rate Change	41110	3	(8,361)	CA	0.000%	-	
DIT Expense - Tax Rate Change	41110	3	(385)	IDU	0.000%	-	
DIT Expense - Tax Rate Change	41110	3	48,413	OR	100.000%	48,413	
DIT Expense - Tax Rate Change	41110	3	(106,340)	OTHER	0.000%	-	
DIT Expense - Tax Rate Change	41110	3	30,964	UT	0.000%	-	
DIT Expense - Tax Rate Change	41110	3	(28,062)	WYP	0.000%	-	
DIT Expense - Tax Rate Change	41110	3	(137,274)	CIAC	26.929%	(36,967)	
DIT Expense - Tax Rate Change	41110	3	(4,311,449)	SCHMDEXP	29.342%	(1,265,072)	
DIT Expense - Tax Rate Change	41110	3	57,534	SE	28.751%	16,542	
DIT Expense - Tax Rate Change	41110	3	40,638	SG	29.956%	12,173	
DIT Expense - Tax Rate Change	41110	3	(40,474)	SNP	28.413%	(11,500)	
DIT Expense - Tax Rate Change	41110	3	50,670	SO	30.017%	15,210	
DIT Expense - Tax Rate Change	41110	3	(135)	TROJD	29.740%	(40)	
			(4,404,261)			(1,221,241)	
DIT Expense - Tax Rate Change	41010	3	(1,765)	CA	0.000%	-	
DIT Expense - Tax Rate Change	41010	3	1,734	IDU	0.000%	-	
DIT Expense - Tax Rate Change	41010	3	(47,453)	OR	100.000%	(47,453)	
DIT Expense - Tax Rate Change	41010	3	(1,288,214)	OTHER	0.000%	-	
DIT Expense - Tax Rate Change	41010	3	(592)	UT	0.000%	-	
DIT Expense - Tax Rate Change	41010	3	(23,239)	WYP	0.000%	-	
DIT Expense - Tax Rate Change	41010	3	(5,201)	WYU	0.000%	-	
DIT Expense - Tax Rate Change	41010	3	62,049	GPS	30.026%	18,631	
DIT Expense - Tax Rate Change	41010	3	123,889	SG	29.956%	37,112	
DIT Expense - Tax Rate Change	41010	3	56,092	SNP	28.413%	15,937	
DIT Expense - Tax Rate Change	41010	3	(97,352)	SO	30.017%	(29,222)	
DIT Expense - Tax Rate Change	41010	3	5,098,884	TAXDEPR	29.685%	1,513,613	
			3,878,832			1,508,618	
ADIT - Chehalis Mitigation Obligation	190	3	(57,751)	SG	29.956%	(17,300)	
ADIT - Tax Rate Change	190	3	127,792	CA	0.000%	-	
ADIT - Tax Rate Change	190	3	349,205	IDU	0.000%	-	
ADIT - Tax Rate Change	190	3	1,246,831	OR	100.000%	1,246,831	
ADIT - Tax Rate Change	190	3	429,094	OTHER	0.000%	-	
ADIT - Tax Rate Change	190	3	2,689,732	UT	0.000%	-	
ADIT - Tax Rate Change	190	3	837,389	WYP	0.000%	-	
ADIT - Tax Rate Change	190	3	79,388	BADDEBT	50.067%	39,747	
ADIT - Tax Rate Change	190	3	83,900	SE	28.751%	24,123	
ADIT - Tax Rate Change	190	3	216,957	SG	29.956%	64,991	
ADIT - Tax Rate Change	190	3	46,630	SNPD	26.929%	12,557	
ADIT - Tax Rate Change	190	3	157,402	SO	30.017%	47,247	
ADIT - Tax Rate Change	190	3	17,850	TROJD	29.740%	5,309	
			6,282,170			1,440,804	

Description of Adjustment:

The company has reached an agreement with Portland General Electric (“PGE”) to sell its Washington service territory and certain associated assets. This removes non-situs tax balances related to the assets being sold, as well as the income tax rate change impacts on deferred income tax expense, accumulated deferred income tax balances and regulatory liabilities.

PacifiCorp PAGE WA_12.1
Oregon General Rate Case - December 2027
Pro Forma Tax Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
ADIT - Tax Rate Change	282	3	(535,299)	CA	0.000%	-	
ADIT - Tax Rate Change	282	3	(521,711)	IDU	0.000%	-	
ADIT - Tax Rate Change	282	3	(1,229,734)	OR	100.000%	(1,229,734)	
ADIT - Tax Rate Change	282	3	(15,783)	OTHER	0.000%	-	
ADIT - Tax Rate Change	282	3	(4,137,273)	UT	0.000%	-	
ADIT - Tax Rate Change	282	3	(1,209,441)	WYP	0.000%	-	
ADIT - Tax Rate Change	282	3	(4,049)	SE	28.751%	(1,164)	
ADIT - Tax Rate Change	282	3	(36,308,221)	SG	29.956%	(10,876,313)	
ADIT - Tax Rate Change	282	3	(6,322)	SNP	28.413%	(1,796)	
ADIT - Tax Rate Change	282	3	(1,487,929)	SO	30.017%	(446,630)	
			(45,455,762)			(12,555,637)	
ADIT - Tax Rate Change	283	3	9,818	CA	0.000%	-	
ADIT - Tax Rate Change	283	3	(1,062)	IDU	0.000%	-	
ADIT - Tax Rate Change	283	3	(22,411)	OR	100.000%	(22,411)	
ADIT - Tax Rate Change	283	3	(3,179,463)	OTHER	0.000%	-	
ADIT - Tax Rate Change	283	3	(31,751)	UT	0.000%	-	
ADIT - Tax Rate Change	283	3	(117,646)	WYP	0.000%	-	
ADIT - Tax Rate Change	283	3	16,083	WYU	0.000%	-	
ADIT - Tax Rate Change	283	3	(110,657)	GPS	30.026%	(33,225)	
ADIT - Tax Rate Change	283	3	(21,279)	SE	28.751%	(6,118)	
ADIT - Tax Rate Change	283	3	(18,775)	SG	29.956%	(5,624)	
ADIT - Tax Rate Change	283	3	(5,467)	SNP	28.413%	(1,553)	
ADIT - Tax Rate Change	283	3	(472,981)	SO	30.017%	(141,974)	
			(3,955,591)			(210,905)	
Tax Reg Liabilities - Tax Rate Change	254	3	(134,401)	CA	0.000%	-	
Tax Reg Liabilities - Tax Rate Change	254	3	(343,401)	IDU	0.000%	-	
Tax Reg Liabilities - Tax Rate Change	254	3	(1,352,301)	OR	100.000%	(1,352,301)	
Tax Reg Liabilities - Tax Rate Change	254	3	(2,668,705)	UT	0.000%	-	
Tax Reg Liabilities - Tax Rate Change	254	3	(843,037)	WYU	0.000%	-	
			(5,341,845)			(1,352,301)	
Total Adjustment			**(49,054,209)**			**(12,407,962)**	

Description of Adjustment:

The company has reached an agreement with Portland General Electric (“PGE”) to sell its Washington service territory and certain associated assets. This removes non-situs tax balances related to the assets being sold, as well as the income tax rate change impacts on deferred income tax expense, accumulated deferred income tax balances and regulatory liabilities.

PacifiCorp PAGE WA_13
Oregon General Rate Case - December 2027
Prepaid Overhauls Removal

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Prepaid Overhauls	186M	3	9,309,909	SG	29.956%	2,788,831	WA_13.1
			9,309,909				

Description of Adjustment:

The company has entered into an agreement with Portland General Electric (“PGE”) to sell its Washington service territory and certain related assets. The Test Period includes a forecasted level of prepaid overhaul rate base for the Chehalis generation asset which will be transferred to the PGE as part of this transaction. This unadjusted Chehalis prepaid overhaul rate base is removed in Adjustment WA_6, leaving the pro forma portion remaining in the Test Period. This adjustment removes the remaining portion of the Chehalis prepaid overhaul rate base from the Test Period.

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Oregon General Rate Case - December 2027
Prepaid Overhauls Removal

	ACCOUNT	Type	Adj 8.15 TOTAL COMPANY	REVISED TOTAL COMPANY	Adjustment Change	REF#
Adjustment to Rate Base:						
Prepaid Overhauls	186M	3	(1,396,007)	7,913,902	9,309,909	WA_13
			(1,396,007)	7,913,902		
			Ref PAC/802	Ref WA_13.2		

PacifiCorp PAGE WA_13.2
Oregon General Rate Case - December 2027
Prepaid Overhauls Removal
Summary of Balances

Overhaul Prepayments by Plant	Account	Factor	Actuals Jun-2025 EOP Balance	Pro Forma Dec-2027 13-Mth. Avg. Balance	Adjustment	Ref.
Lake Side 1	186M	SG	430,240	15,703,604	15,273,364	PAC/802
Chehalis	***186M***	***SG***			**-**	**Removed*
Currant Creek	186M	SG	23,886,735	8,300,247	(15,586,488)	PAC/802
Lake Side 2	186M	SG	11,539,319	20,773,061	9,233,742	PAC/802
Chehalis O&M	186M	SG	2,249,341	1,085,230	(1,164,111)	PAC/802
Currant Creek O&M	186M	SG	1,060,568	1,217,962	157,394	PAC/802
Total			39,166,202	47,080,104	**7,913,902**	

PacifiCorp PAGE WA_14
Oregon General Rate Case - December 2027
Washington Unamortized Pension Loss

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Pension	926	3	(883,276)	SO	30.017%	(265,132)	9.15.1
Post-Retirement	926	3	260,450	SO	30.017%	78,179	9.15.1

Description of Adjustment:

The company has entered into an agreement with Portland General Electric (“PGE”) to sell its Washington service territory and certain related assets. Test Period expenses in this case reflects a forecasted level of pension and post-retirement amortizations which includes Washington's share of unrealized gains/losses. This adjustment removes Washington's share of the amortization from the Test Period.

PacifiCorp PAGE WA_14.1
Oregon General Rate Case - December 2027
Washington Unamortized Pension Loss
Unamortized Gains/Loss Amortization - Washington Allocation

	GL 554012	GL 554022		
	Pension Non-Service Expense	Post-Retirement Non-Service Expense		
Description	Forecasted Twelve Months Ending December 2027	Forecasted Twelve Months Ending December 2027	FERC Acct	Factor
Jan-2027	73,606	(21,704)	926	SO
Feb-2027	73,606	(21,704)	926	SO
Mar-2027	73,606	(21,704)	926	SO
Apr-2027	73,606	(21,704)	926	SO
May-2027	73,606	(21,704)	926	SO
Jun-2027	73,606	(21,704)	926	SO
Jul-2027	73,606	(21,704)	926	SO
Aug-2027	73,606	(21,704)	926	SO
Sep-2027	73,606	(21,704)	926	SO
Oct-2027	73,606	(21,704)	926	SO
Nov-2027	73,606	(21,704)	926	SO
Dec-2027	73,606	(21,704)	926	SO
Forecasted Amortization	**883,276**	**(260,450)**		
	Ref WA_14	**Ref WA_14**		

PacifiCorp PAGE WA_15
Oregon General Rate Case - December 2027
Washington Accelerated Depreciation and Decommissioning

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Reserve: Plant							
Steam Plant Accumulated Depreciation	108SP	3	(45,723,717)	SG	29.956%	(13,696,773)	WA_15.1
Adjustment to Reserve: GSU							
Transmission Plant Accumulated Depr.	108TP	3	(877,914)	SG	29.956%	(262,984)	WA_15.1
Adjustment to Regulatory Liabilities							
Steam Plant Decommissioning	108SP	3	(22,172,806)	SG	29.956%	(6,641,977)	WA_15.2
WA Bridger Mine Closure	254	3	(14,167,242)	SG	29.956%	(4,243,870)	WA_15.3
WA Coal Other Plant Closure	254	3	(8,421,206)	SG	29.956%	(2,522,615)	WA_15.3
Adjustment to Tax							
Steam Plant Accumulated Depreciation	282	3	11,957,732	SG	29.956%	3,582,000	
Steam Plant Decommissioning	282	3	5,451,539	SG	29.956%	1,633,036	
WA Bridger Mine Closure	190	3	3,483,243	SG	29.956%	1,043,423	
WA Coal Other Plant Closure	190	3	2,070,488	SG	29.956%	620,225	

Description of Adjustment:

This adjustment includes into Test Period results rate base credits related to the Washington accelerated depreciation for Jim Bridger and Colstrip steam plants. This adjustment also includes into Oregon's rate base Oregon's allocated share of the regulatory liability balances for Bridger coal mine incremental depreciation and reclamation costs and other plant closure costs associated with Jim Bridger and Colstrip steam plants.

PacifiCorp PAGE WA_15.1
Oregon General Rate Case - December 2027
Washington Accelerated Depreciation and Decommissioning

Washington Accumulated Depreciation Reserve

	Steam Plant	
	Incremental Depr	**Balance**
Dec-26	437,703	(46,834,810)
Jan-27	437,703	(46,397,106)
Feb-27	437,703	(45,959,403)
Mar-27	437,703	(45,521,700)
Apr-27	-	(45,521,700)
May-27	-	(45,521,700)
Jun-27	-	(45,521,700)
Jul-27	-	(45,521,700)
Aug-27	-	(45,521,700)
Sep-27	-	(45,521,700)
Oct-27	-	(45,521,700)
Nov-27	-	(45,521,700)
Dec-27	-	(45,521,700)
	13 Month Average	**(45,723,717)** **Ref WA_15**

	GSU Transmission Plant	
	Incremental Depr	**Balance**
Dec-26	1,710	(882,255)
Jan-27	1,710	(880,545)
Feb-27	1,710	(878,835)
Mar-27	1,710	(877,125)
Apr-27	-	(877,125)
May-27	-	(877,125)
Jun-27	-	(877,125)
Jul-27	-	(877,125)
Aug-27	-	(877,125)
Sep-27	-	(877,125)
Oct-27	-	(877,125)
Nov-27	-	(877,125)
Dec-27	-	(877,125)
	13 Month Average	**(877,914)** **Ref WA_15**

PacifiCorp PAGE WA_15.2
Oregon General Rate Case - December 2027
Washington Accelerated Depreciation and Decommissioning

Incremental Decommissioning

	Steam Production Plant	
	Accrual	**Balance**
Dec-26	(297,468)	(21,417,695)
Jan-27	(297,468)	(21,715,163)
Feb-27	(297,468)	(22,012,631)
Mar-27	(297,468)	(22,310,099)
Apr-27	-	(22,310,099)
May-27	-	(22,310,099)
Jun-27	-	(22,310,099)
Jul-27	-	(22,310,099)
Aug-27	-	(22,310,099)
Sep-27	-	(22,310,099)
Oct-27	-	(22,310,099)
Nov-27	-	(22,310,099)
Dec-27	-	(22,310,099)
13 Month Average		**(22,172,806)** **Ref WA_15**

PacifiCorp PAGE WA_15.3
Oregon General Rate Case - December 2027
Washington Accelerated Depreciation and Decommissioning

Bridger Mine Incremental Depreciation & Reclamation

	Bridger Mine	
	Accrual	**Balance**
Dec-26	(165,501)	(13,747,123)
Jan-27	(165,501)	(13,912,624)
Feb-27	(165,501)	(14,078,125)
Mar-27	(165,501)	(14,243,627)
Apr-27	-	(14,243,627)
May-27	-	(14,243,627)
Jun-27	-	(14,243,627)
Jul-27	-	(14,243,627)
Aug-27	-	(14,243,627)
Sep-27	-	(14,243,627)
Oct-27	-	(14,243,627)
Nov-27	-	(14,243,627)
Dec-27	-	(14,243,627)
	13 Month Average	**(14,167,242)** **Ref WA_15**

Other Plant Closure Costs

	Steam Production Plant	
	Accrual	**Balance**
Dec-26	(112,978)	(8,134,415)
Jan-27	(112,978)	(8,247,393)
Feb-27	(112,978)	(8,360,371)
Mar-27	(112,978)	(8,473,349)
Apr-27	-	(8,473,349)
May-27	-	(8,473,349)
Jun-27	-	(8,473,349)
Jul-27	-	(8,473,349)
Aug-27	-	(8,473,349)
Sep-27	-	(8,473,349)
Oct-27	-	(8,473,349)
Nov-27	-	(8,473,349)
Dec-27	-	(8,473,349)
	13 Month Average	**(8,421,206)** **Ref WA_15**

Tab 4 - Allocation Factors
Post-Service Area Transfer

Oregon General Rate Case
Pro Forma Factors December 2027
2020 Protocol Factors
Post-Service Area Transfer

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2027
Post-Service Area Transfer

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Situs	S		-	-	-	-	-	-	-	-	-	Situs
System Generation	SG		1.4963%	29.9555%	0.0000%	48.1164%	6.0718%	14.3556%	0.0044%	0.0000%	0.0000%	Pg 4.13
System Generation (Pac. Power Costs on SG)	SG-P		1.4963%	29.9555%	0.0000%	48.1164%	6.0718%	14.3556%	0.0044%	0.0000%	0.0000%	Pg 4.13
System Generation (R.M.P. Costs on SG)	SG-U		1.4963%	29.9555%	0.0000%	48.1164%	6.0718%	14.3556%	0.0044%	0.0000%	0.0000%	Pg 4.13
System Generation (Wind Plant on SG)	SG-W		1.4963%	29.9555%	0.0000%	48.1164%	6.0718%	14.3556%	0.0044%	0.0000%	0.0000%	Pg 4.13
Divisional Generation - Pac. Power	DGP		3.4110%	68.2860%	0.0000%	0.0000%	0.0000%	28.3030%	0.0000%	0.0000%	0.0000%	Pg 4.13
Divisional Generation - R.M.P.	DGU		0.0000%	0.0000%	0.0000%	85.7197%	10.8169%	3.4556%	0.0078%	0.0000%	0.0000%	Pg 4.13
System Capacity	SC		1.5484%	30.3569%	0.0000%	48.1287%	5.9453%	14.0167%	0.0041%	0.0000%	0.0000%	Pg 4.13
System Energy	SE		1.3401%	28.7515%	0.0000%	48.0797%	6.4514%	15.3721%	0.0053%	0.0000%	0.0000%	Pg 4.13
System Overhead	SO		3.2211%	30.0169%	0.0000%	47.8791%	5.7880%	13.0919%	0.0030%	0.0000%	0.0000%	Pg 4.7
Gross Plant-System	GPS		3.4307%	30.0257%	0.0000%	47.8447%	5.7543%	12.9417%	0.0029%	0.0000%	0.0000%	Pg 4.6
System Net Plant	SNP		4.2348%	28.4128%	0.0000%	49.4820%	5.6540%	12.2138%	0.0027%	0.0000%	0.0000%	Pg 4.7
Division Net Plant Distribution	SNPD		8.4385%	26.9294%	0.0000%	51.3291%	4.7911%	8.5120%	0.0000%	0.0000%	0.0000%	Pg 4.5
Customer - System	CN		2.3565%	32.3629%	0.0000%	53.2506%	4.6016%	7.4284%	0.0000%	0.0000%	0.0000%	Pg 4.8
CIAC	CIAC		8.4385%	26.9294%	0.0000%	51.3291%	4.7911%	8.5120%	0.0000%	0.0000%	0.0000%	Pg 4.8
Bad Debt Expense	BADDEBT		6.2201%	50.0671%	0.0000%	33.2464%	2.2882%	8.1782%	0.0000%	0.0000%	0.0000%	Pg 4.7
Accumulated Investment Tax Credit 1984	ITC84		3.2870%	70.9760%	14.1800%	0.0000%	0.0000%	10.9460%	0.0000%	0.0000%	0.6110%	Fixed
Accumulated Investment Tax Credit 1985	ITC85		5.4200%	67.6900%	13.3600%	0.0000%	0.0000%	11.6100%	0.0000%	0.0000%	1.9200%	Fixed
Accumulated Investment Tax Credit 1986	ITC86		4.7890%	64.6080%	13.1260%	0.0000%	0.0000%	15.5000%	0.0000%	0.0000%	1.9770%	Fixed
Accumulated Investment Tax Credit 1988	ITC88		4.2700%	61.2000%	14.9600%	0.0000%	0.0000%	16.7100%	0.0000%	0.0000%	2.8600%	Fixed
Accumulated Investment Tax Credit 1989	ITC89		4.8806%	56.3558%	15.2688%	0.0000%	0.0000%	20.6776%	0.0000%	0.0000%	2.8172%	Fixed
Accumulated Investment Tax Credit 1990	ITC90		1.5047%	15.9356%	3.9132%	46.9355%	13.9815%	17.3435%	0.0000%	0.0000%	0.3860%	Fixed
Other Electric	OTHER		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	Situs
Non-Utility	NUTIL		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	Situs
System Net Steam Plant	SNPPS		1.4727%	33.5218%	0.0000%	45.5066%	5.8931%	13.6008%	0.0049%	0.0000%	0.0000%	Pg 4.3
System Net Transmission Plant	SNPT		1.4963%	29.9555%	0.0000%	48.1164%	6.0718%	14.3556%	0.0044%	0.0000%	0.0000%	Pg 4.4
System Net Production Plant	SNPP		1.5982%	26.3330%	0.0000%	50.5287%	6.4468%	15.0883%	0.0050%	0.0000%	0.0000%	Pg 4.4
System Net Hydro Plant	SNPPH		1.4963%	29.9555%	0.0000%	48.1164%	6.0718%	14.3556%	0.0044%	0.0000%	0.0000%	Pg 4.3
System Net Other Production Plant	SNPPO		1.4963%	29.9555%	0.0000%	48.1164%	6.0718%	14.3556%	0.0044%	0.0000%	0.0000%	Pg 4.4
System Net General Plant	SNPG		3.0878%	29.9593%	0.0000%	45.3395%	6.7450%	14.8665%	0.0019%	0.0000%	0.0000%	Pg 4.5
System Net Intangible Plant	SNPI		1.6005%	29.0502%	0.0000%	46.5126%	7.3511%	15.4817%	0.0039%	0.0000%	0.0000%	Pg 4.6
Trojan Plant Allocator	TROJP		1.4726%	29.7726%	0.0000%	48.1109%	6.1294%	14.5100%	0.0045%	0.0000%	0.0000%	Pg 4.9
Trojan Decommissioning Allocator	TROJD		1.4684%	29.7403%	0.0000%	48.1099%	6.1396%	14.5372%	0.0046%	0.0000%	0.0000%	Pg 4.9
DIT Balance	DITBAL		2.2902%	27.8220%	0.0000%	50.0665%	6.0315%	13.8071%	0.0036%	-0.0209%	0.0000%	Pg 4.7
Tax Depreciation	TAXDEPR		3.9304%	29.6852%	0.0000%	48.3870%	5.6406%	12.3458%	0.0031%	0.0079%	0.0000%	Pg 4.10
SCHMAT Depreciation Expense	SCHMDEXP		3.5337%	29.3422%	0.0000%	48.1475%	5.7823%	13.1914%	0.0030%	0.0000%	0.0000%	Pg 4.10
System Generation Cholla Transaction	SGCT		1.4964%	29.9568%	0.0000%	48.1186%	6.0721%	14.3562%	0.0000%	0.0000%	0.0000%	Pg 4.2

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DESCRIPTION **CALCULATION OF FACTORS** **Pro Forma Factors December 31, 2027**	**2020 PROTOCOL FACTOR**		**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC-UPL**	**OTHER**	**NON-UTILITY**	**Page Ref.**
DESCRIPTION OF FACTOR		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
STEAM :												
STEAM PRODUCTION PLANT												
	S	0	0	0	0	0	0	0	0	0	0	
	DGP	0	0	0	0	0	0	0	0	0	0	
	DGU	0	0	0	0	0	0	0	0	0	0	
	SG	7,147,366,363	106,947,451	2,141,030,109	0	3,439,058,231	433,972,868	1,026,043,981	313,724	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
		7,147,366,363	106,947,451	2,141,030,109	0	3,439,058,231	433,972,868	1,026,043,981	313,724	0	0	
LESS ACCUMULATED DEPRECIATION												
	S	(109,570,593)	(1,856,680)	0	0	(76,741,331)	(8,297,223)	(22,675,360)	0	0	0	
	DGP	0	0	0	0	0	0	0	0	0	0	
	DGU	0	0	0	0	0	0	0	0	0	0	
	SG	(6,117,450,481)	(91,536,617)	(1,832,513,545)	0	(2,943,499,376)	(371,438,568)	(878,193,858)	(268,517)	0	0	
	SG-W	0	0	0	0	0	0	0	0	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
		(6,227,021,074)	(93,393,296)	(1,832,513,545)	0	(3,020,240,706)	(379,735,791)	(900,869,218)	(268,517)	0	0	
TOTAL NET STEAM PLANT		920,345,289	13,554,154	308,516,564	0	418,817,525	54,237,076	125,174,763	45,207	0	0	
SNPPS												
SYSTEM NET PLANT PRODUCTION STEAM		100.0000%	1.4727%	33.5218%	0.0000%	45.5066%	5.8931%	13.6008%	0.0049%	0.0000%	0.0000%	
HYDRO:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
HYDRO PRODUCTION PLANT												
	S	0	0	0	0	0	0	0	0	0	0	
	DGP	0	0	0	0	0	0	0	0	0	0	
	DGU	0	0	0	0	0	0	0	0	0	0	
	SG	1,325,006,862	19,826,339	396,912,575	0	637,546,128	80,451,595	190,212,065	58,159	0	0	
		1,325,006,862	19,826,339	396,912,575	0	637,546,128	80,451,595	190,212,065	58,159	0	0	
LESS ACCUMULATED DEPRECIATION (incl hydro amortization)												
	S	0	0	0	0	0	0	0	0	0	0	
	DGP	0	0	0	0	0	0	0	0	0	0	
	DGU	0	0	0	0	0	0	0	0	0	0	
	SG	(561,784,935)	(8,406,099)	(168,285,547)	-	(270,310,910)	(34,110,385)	(80,647,335)	(24,659)	0	0	
		(561,784,935)	(8,406,099)	(168,285,547)	0	(270,310,910)	(34,110,385)	(80,647,335)	(24,659)	0	0	
TOTAL NET HYDRO PRODUCTION PLANT		763,221,927	11,420,240	228,627,027	0	367,235,219	46,341,210	109,564,730	33,501	0	0	
SNPPH												
SYSTEM NET PLANT PRODUCTION HYDRO		100.0000%	1.4963%	29.9555%	0.0000%	48.1164%	6.0718%	14.3556%	0.0044%	0.0000%	0.0000%	

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DESCRIPTION	2020 PROTOCOL FACTOR	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
OTHER:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
OTHER PRODUCTION PLANT (EXCLUDES EXPERIMENTAL)												
	S	0	0	0	0	0	0	0	0	0	0	
	DGP & DGU	0	0	0	0	0	0	0	0	0	0	
	SG	1,747,556,885	26,149,038	523,489,593	0	840,862,156	106,107,933	250,871,458	76,707	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		1,747,556,885	26,149,038	523,489,593	0	840,862,156	106,107,933	250,871,458	76,707	0	0	
LESS ACCUMULATED DEPRECIATION												
	S	0	0	0	0	0	0	0	0	0	0	
	DGP	0	0	0	0	0	0	0	0	0	0	
	DGU	0	0	0	0	0	0	0	0	0	0	
	SG	(643,360,500)	(9,626,730)	(192,721,925)	-	(309,562,168)	(39,063,480)	(92,357,959)	(28,239)	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		(643,360,500)	(9,626,730)	(192,721,925)	0	(309,562,168)	(39,063,480)	(92,357,959)	(28,239)	0	0	
TOTAL NET OTHER PRODUCTION PLANT		1,104,196,385	16,522,308	330,767,668	0	531,299,988	67,044,453	158,513,499	48,467	0	0	
SNPPO												
SYSTEM NET PLANT PRODUCTION OTHER		100.0000%	1.4963%	29.9555%	0.0000%	48.1164%	6.0718%	14.3556%	0.0044%	0.0000%	0.0000%	

PRODUCTION:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**
TOTAL PRODUCTION PLANT											
	S	0	0	0	0	0	0	0	0	0	0
	DGP & DGU	0	0	0	0	0	0	0	0	0	0
	SG	10,219,930,110	152,922,827	3,061,432,276	0	4,917,466,515	620,532,396	1,467,127,504	448,590	0	0
	SSGCH	0	0	0	0	0	0	0	0	0	0
	SSGCT	0	0	0	0	0	0	0	0	0	0
		10,219,930,110	152,922,827	3,061,432,276	0	4,917,466,515	620,532,396	1,467,127,504	448,590	0	0
LESS ACCUMULATED DEPRECIATION											
	S	(259,406,552)	(1,856,680)	(149,702,789)	-	(76,874,500)	(8,297,223)	(22,675,360)	0	0	0
	DGP	0	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG-P	(7,973,067,186)	(119,302,575)	(2,388,373,009)	-	(3,836,356,070)	(484,107,663)	(1,144,577,902)	(349,967)	0	0
	SSGCH	0	0	0	0	0	0	0	0	0	0
	SSGCT	0	0	0	0	0	0	0	0	0	0
		(8,232,473,737)	(121,159,255)	(2,538,075,798)	0	(3,913,230,569)	(492,404,887)	(1,167,253,262)	(349,967)	0	0
TOTAL NET PRODUCTION PLANT		1,987,456,372	31,763,573	523,356,479	0	1,004,235,946	128,127,510	299,874,243	98,623	0	0
SNPP											
SYSTEM NET PRODUCTION PLANT		100.0000%	1.5982%	26.3330%	0.0000%	50.5287%	6.4468%	15.0883%	0.0050%	0.0000%	0.0000%

TRANSMISSION:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
TRANSMISSION PLANT									
	DGP	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0
	SG	12,002,066,918	179,589,291	3,595,280,462	0	5,774,967,299	728,739,949	1,722,963,102	526,815
		12,002,066,918	179,589,291	3,595,280,462	0	5,774,967,299	728,739,949	1,722,963,102	526,815
LESS ACCUMULATED DEPRECIATION									
	DGP	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0
	SG	(2,902,464,888)	(43,430,154)	(869,448,185)	0	(1,396,562,769)	(176,231,488)	(416,664,891)	(127,400)
		(2,902,464,888)	(43,430,154)	(869,448,185)	0	(1,396,562,769)	(176,231,488)	(416,664,891)	(127,400)
TOTAL NET TRANSMISSION PLANT		9,099,602,030	136,159,138	2,725,832,277	0	4,378,404,530	552,508,461	1,306,298,211	399,415
SNPT									
SYSTEM NET PLANT TRANSMISSION		100.0000%	1.4963%	29.9555%	0.0000%	48.1164%	6.0718%	14.3556%	0.0044%

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
DISTRIBUTION:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
DISTRIBUTION PLANT - PACIFIC POWER	S	5,136,305,173	827,396,454	3,365,009,636	0	0	0	943,899,083	0			
LESS ACCUMULATED DEPRECIATION	S	(1,936,175,316)	(194,365,011)	(1,344,836,407)	0	0	0	(396,973,898)	0			
		3,200,129,857	633,031,443	2,020,173,229	0	0	0	546,925,185	0			
DNPDP												
DIVISION NET PLANT DISTRIBUTION PACIFIC POWER		100.0000%	19.7814%	63.1279%	0.0000%	0.0000%	0.0000%	17.0907%	0.0000%			
DISTRIBUTION PLANT - ROCKY MOUNTAIN POWER												
	S	6,019,049,735	0	0	0	5,296,719,195	555,841,103	166,489,437	0			
LESS ACCUMULATED DEPRECIATION												
	S	(1,717,441,717)	0	0	0	(1,446,148,347)	(196,426,924)	(74,866,447)	0			
		4,301,608,017	0	0	0	3,850,570,848	359,414,179	91,622,990	0			
DNPDU												
DIVISION NET PLANT DISTRIBUTION R.M.P.		100.0000%	0.0000%	0.0000%	0.0000%	89.5147%	8.3553%	2.1300%	0.0000%			
TOTAL NET DISTRIBUTION PLANT		7,501,737,875	633,031,443	2,020,173,229	0	3,850,570,848	359,414,179	638,548,174	0			
DNPD & SNPD												
SYSTEM NET PLANT DISTRIBUTION		100.0000%	8.4385%	26.9294%	0.0000%	51.3291%	4.7911%	8.5120%	0.0000%			
GENERAL:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
GENERAL PLANT												
	S	545,405,621	16,465,606	163,073,744	0	227,133,136	45,607,810	93,125,325	0			
	DGP	0	0	0	0	0	0	0	0			
	DGU	0	0	0	0	0	0	0	0			
	SE	2,544,783	34,103	731,662	0	1,223,524	164,173	391,186	135			
	SG	107,468,784	1,608,077	32,192,823	0	51,710,153	6,525,276	15,427,738	4,717			
	SO	980,965,690	31,597,585	294,455,089	0	469,677,692	56,778,251	128,427,215	29,858			
	CN	237,089,255	5,586,984	76,729,074	0	126,251,380	10,909,953	17,611,864	0			
	DEU	0	0	0	0	0	0	0	0			
	SSGCT	0	0	0	0	0	0	0	0			
	SSGCH	0	0	0	0	0	0	0	0			
	Remove Capital Lease	(26,251,829)	(93,302)	(9,684,095)	0	(9,682,276)	(2,481,125)	(4,310,759)	(274)			
		1,847,222,304	55,199,053	557,498,298	-	866,313,608	117,504,339	250,672,570	34,436			
LESS ACCUMULATED DEPRECIATION												
	S	(252,357,429)	(7,744,769)	(74,024,077)	0	(108,751,390)	(20,822,882)	(41,014,311)	0			
	DGP	165,454	2,476	49,562	0	79,610	10,046	23,752	7			
	DGU	513,009	7,676	153,675	0	246,842	31,149	73,645	23			
	SE	(1,561,399)	(20,924)	(448,925)	0	(750,716)	(100,732)	(240,020)	(83)			
	SG	(59,592,307)	(891,691)	(17,851,180)	0	(28,673,696)	(3,618,318)	(8,554,805)	(2,616)			
	SO	(598,627,520)	(19,282,207)	(179,689,179)	0	(286,617,559)	(34,648,535)	(78,371,819)	(18,220)			
	CN	(222,176,030)	(5,235,555)	(71,902,715)	0	(118,310,003)	(10,223,703)	(16,504,054)	0			
	SSGCT	0	0	0	0	0	0	0	0			
	SSGCH	0	0	0	0	0	0	0	0			
		(1,133,636,222)	(33,164,995)	(343,712,839)	-	(542,776,912)	(69,372,975)	(144,587,611)	(20,889)			
TOTAL NET GENERAL PLANT		713,586,082	22,034,057	213,785,460	0	323,536,696	48,131,364	106,084,958	13,547			
SNPG												
SYSTEM NET GENERAL PLANT		100.0000%	3.0878%	29.9593%	0.0000%	45.3395%	6.7450%	14.8665%	0.0019%			

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
MINING:		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC			
GENERAL MINING PLANT	SE	39,748,016	532,663	11,428,138	0	19,110,719	2,564,293	6,110,099	2,104			
LESS ACCUMULATED DEPRECIATION	SE	0	0	0	0	0	0	0	0			
		39,748,016	532,663	11,428,138	0	19,110,719	2,564,293	6,110,099	2,104			
SNPM												
SYSTEM NET PLANT MINING		100.0000%	1.3401%	28.7515%	0.0000%	48.0797%	6.4514%	15.3721%	0.0053%			

INTANGIBLE:		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC
INTANGIBLE PLANT									
	S	21,985,453	469,320	4,597,089	0	7,436,155	4,351,609	5,131,280	0
	DGP	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0
	SE	0	0	0	0	0	0	0	0
	CN	(3,178,870)	(74,910)	(1,028,776)	0	(1,692,767)	(146,280)	(236,138)	0
	SG	290,192,345	4,342,205	86,928,599	0	139,630,225	17,619,861	41,658,716	12,738
	SO	(13,908,637)	(448,007)	(4,174,936)	0	(6,659,332)	(805,031)	(1,820,907)	(423)
	SSGCT	0	0	0	0	0	0	0	0
	SSGCH	0	0	0	0	0	0	0	0
		295,090,290	4,288,608	86,321,976	0	138,714,281	21,020,159	44,732,951	12,314
LESS ACCUMULATED AMORTIZATION									
	S	(2,126,037)	3,021	(170,171)	0	(576,883)	(995,018)	(386,986)	0
	DGP	0	0	0	0	0	0	0	0
	DGU	18,570	278	5,563	0	8,935	1,128	2,666	1
	SE	0	0	0	0	0	0	0	0
	CN	3,178,870	74,910	1,028,776	0	1,692,767	146,280	236,138	0
	SG	(141,946,151)	(2,123,968)	(42,520,695)	0	(68,299,434)	(8,618,668)	(20,377,155)	(6,231)
	SO	13,908,637	448,007	4,174,936	0	6,659,332	805,031	1,820,907	423
	SSGCT	0	0	0	0	0	0	0	0
	SSGCH	0	0	0	0	0	0	0	0
		(126,966,110)	(1,597,753)	(37,481,590)	0	(60,515,283)	(8,661,248)	(18,704,430)	(5,806)
TOTAL NET INTANGIBLE PLANT		168,124,180	2,690,856	48,840,386	0	78,198,997	12,358,912	26,028,521	6,508
SNPI									
SYSTEM NET INTANGIBLE PLANT		100.0000%	1.6005%	29.0502%	0.0000%	46.5126%	7.3511%	15.4817%	0.0039%

GROSS PLANT:	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	OTHER	NUTIL
PRODUCTION PLANT	10,219,930,110	152,922,827	3,061,432,276	0	4,917,466,515	620,532,396	448,590	448,590	0	0
TRANSMISSION PLANT	12,002,066,918	179,589,291	3,595,280,462	0	5,774,967,299	728,739,949	1,722,963,102	526,815	0	0
DISTRIBUTION PLANT	11,155,354,908	827,396,454	3,365,009,636	0	5,296,719,195	555,841,103	1,110,388,520	0	0	0
GENERAL PLANT	1,886,970,320	55,731,716	568,926,436	0	885,424,327	120,068,632	256,782,669	36,540	0	0
INTANGIBLE PLANT	295,090,290	4,288,608	86,321,976	0	138,714,281	21,020,159	44,732,951	12,314	0	0
TOTAL GROSS PLANT	35,559,412,546	1,219,928,897	10,676,970,787	0	17,013,291,618	2,046,202,239	3,135,315,832	1,024,259	0	0
GPS										
GROSS PLANT-SYSTEM FACTOR	100.0000%	3.4307%	30.0257%	0.0000%	47.8447%	5.7543%	12.9417%	0.0029%	0.0000%	0.0000%
ACCUMULATED DEPRECIATION AND AMORTIZATION										
PRODUCTION PLANT	(8,232,473,737)	(121,159,255)	(2,538,075,798)	0	(3,913,230,569)	(492,404,887)	(1,167,253,262)	(349,967)	0	0
TRANSMISSION PLANT	(2,902,464,888)	(43,430,154)	(869,448,185)	0	(1,396,562,769)	(176,231,488)	(416,664,891)	(127,400)	0	0
DISTRIBUTION PLANT	(3,653,617,033)	(194,365,011)	(1,344,836,407)	0	(1,446,148,347)	(196,426,924)	(471,840,345)	0	0	0
GENERAL PLANT	(1,133,636,222)	(33,164,995)	(343,712,839)	0	(542,776,912)	(69,372,975)	(144,587,611)	(20,889)	0	0
INTANGIBLE PLANT	(126,966,110)	(1,597,753)	(37,481,590)	0	(60,515,283)	(8,661,248)	(18,704,430)	(5,806)	0	0
	(16,049,157,990)	(393,717,167)	(5,133,554,820)	0	(7,359,233,881)	(943,097,521)	(2,219,050,539)	(504,062)	0	0
NET PLANT	19,510,254,555	826,211,730	5,543,415,968	0	9,654,057,736	1,103,104,718	916,265,292	520,197	0	0

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
SNP												
SYSTEM NET PLANT FACTOR (SNP)		100.0000%	4.2348%	28.4128%	0.0000%	49.4820%	5.6540%	12.2138%	0.0027%	0.0000%	0.0000%	
NON-UTILITY RELATED INTEREST PERCENTAGE		0.0000%										
INT												
INTEREST FACTOR SNP - NON-UTILITY		100.0000%	4.2348%	28.4128%	0.0000%	49.4820%	5.6540%	12.2138%	0.0027%	0.0000%	0.0000%	
TOTAL GROSS PLANT (LESS SO FACTOR)		39,069,856,282	1,258,467,158	11,727,543,726	0	18,706,301,458	2,261,361,578	5,114,993,198	1,189,164	0	0	
SO												
SYSTEM OVERHEAD FACTOR (SO)		100.0000%	3.2211%	30.0169%	0.0000%	47.8791%	5.7880%	13.0919%	0.0030%	0.0000%	0.0000%	

IBT

INCOME BEFORE TAXES		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**
INCOME BEFORE STATE TAXES		2,200,885,404	15,732,278	91,613,363	0	1,338,758,681	205,334,636	422,330,509	16,847,267	110,268,670	0
Interest Synchronization		(53,548,061)	0	0	0	0	0	0	0	(53,548,061)	0
		2,147,337,343	15,732,278	91,613,363	0	1,338,758,681	205,334,636	422,330,509	16,847,267	56,720,609	0
INCOME BEFORE TAXES (FACTOR)		100.0000%	0.7326%	4.2664%	0.0000%	62.3451%	9.5623%	19.6676%	0.7846%	2.6414%	0.0000%

See Calculation of EXCTAX

DITBAL:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**
Jurisdictional ADIT - 12/31/2027 - TOTAL		3,450,541,724	79,024,186	960,009,000	0	1,727,566,530	208,119,815	476,420,239	122,658	(720,703)	0
Jurisdictional ADIT - 12/31/2027 - CA	S	34,504,855	34,504,855	0	0	0	0				
Jurisdictional ADIT - 12/31/2027 - ID	S	36,492,187	0	0	0	0	36,492,187	0	0	0	0
Jurisdictional ADIT - 12/31/2027 - OTHER	S	(720,703)	0	0	0	0	0	0	0	(720,703)	0
Jurisdictional ADIT - 12/31/2027 - OR	S	111,463,388	0	111,463,388	0	0	0	0	0	0	0
Jurisdictional ADIT - 12/31/2027 - SG	SG	2,156,132,048	32,262,629	645,880,370	0	1,037,453,978	130,915,747	309,524,683	94,641	0	0
Jurisdictional ADIT - 12/31/2027 - SG-CAGE	SG	428,707,273	6,414,831	128,421,454	0	206,278,677	26,030,193	61,543,301	18,818	0	0
Jurisdictional ADIT - 12/31/2027 - SG-CAGW	SG	123,686,007	1,850,738	37,050,775	0	59,513,303	7,509,951	17,755,811	5,429	0	0
Jurisdictional ADIT - 12/31/2027 - SO	SO	123,907,078	3,991,133	37,193,013	0	59,325,612	7,171,736	16,221,812	3,771	0	0
Jurisdictional ADIT - 12/31/2027 - UT	UT	364,994,959	0	0	0	364,994,959	0	0	0	0	0
Jurisdictional ADIT - 12/31/2027 - WA	WA	0	0	0	0	0	0	0	0	0	0
Jurisdictional ADIT - 12/31/2027 - WY	WY	71,374,632	0	0	0	0	0	71,374,632	0	0	0
Jurisdictional ADIT - 12/31/2027 - TOTAL		3,450,541,724	79,024,186	960,009,000	0	1,727,566,530	208,119,815	476,420,239	122,658	(720,703)	0
Total PacifiCorp		3,450,541,724	79,024,186	960,009,000	0	1,727,566,530	208,119,815	476,420,239	122,658	(720,703)	0
Percentage of Total (DITBAL)		100.0000%	2.2902%	27.8220%	0.0000%	50.0665%	6.0315%	13.8071%	0.0036%	-0.0209%	0.0000%

BADDEBT

	TOTAL	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**
Account 904 Balance	22,314,531	1,387,976	11,172,235	0	7,418,784	510,611	1,824,925	0	0	0
Bad Debts Expense Allocation Factor - BADDEBT	100.0000%	6.2201%	50.0671%	0.0000%	33.2464%	2.2882%	8.1782%	0.0000%	0.0000%	0.0000%

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Customer Factors		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Total Electric Customers		2,033,643	47,923	658,147	0	1,082,927	93,581	151,067	0	0	0	
CN												
Customer System factor - CN		100.0000%	2.3565%	32.3629%	0.0000%	53.2506%	4.6016%	7.4284%	0.0000%	0.0000%	0.0000%	
Pacific Power Customers		839,832	47,923	658,147	0	0	0	133,762	0	0	0	
CNP												
Customer Service Pacific Power factor - CNP		100.0000%	5.7062%	78.3665%	0.0000%	0.0000%	0.0000%	15.9273%	0.0000%	0.0000%	0.0000%	
Rocky Mountain Power Customers		1,193,811	0	0	0	1,082,927	93,581	17,304	0	0	0	
CNU												
Customer Service R.M.P. factor - CNU		100.0000%	0.0000%	0.0000%	0.0000%	90.7117%	7.8388%	1.4495%	0.0000%	0.0000%	0.0000%	
CIAC		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
TOTAL NET DISTRIBUTION PLANT		7,501,737,875	633,031,443	2,020,173,229	0	3,850,570,848	359,414,179	638,548,174	0	0	0	
CIAC FACTOR: Same as (SNPD Factor)		100.0000%	8.4385%	26.9294%	0.0000%	51.3291%	4.7911%	8.5120%	0.0000%	0.0000%	0.0000%	
EXCTAX												
Excise Tax (Superfund)		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Total Taxable Income		2,081,611,203	14,945,664	86,539,911	0	1,271,820,747	195,067,904	401,213,984	16,004,903	96,018,090	0	
Less Other Electric Items:												
419 OTH		0	0	0	0	0	0	0	0	0	0	
432 OTH		0	0	0	0	0	0	0	0	0	0	
40910 OTH		0	0	0	0	0	0	0	0	0	0	
SCHMDT OTH		0	0	0	0	0	0	0	0	0	0	
SCHMDT (Steam) OTH												
Total Taxable Income Excluding Other		2,081,611,203	14,945,664	86,539,911	0	1,271,820,747	195,067,904	401,213,984	16,004,903	96,018,090	0	
Excise Tax (Superfund) Factor - EXCTAX		100.0000%	0.7180%	4.1574%	0.0000%	61.0979%	9.3710%	19.2742%	0.7689%	4.6127%	0.0000%	
Trojan Allocators		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Premerger												
Dec 1991 Plant		16,918,976										
Dec 1992 Plant		17,094,202										
Average	SG	17,006,589	254,473	5,094,411	0	8,182,965	1,032,604	2,441,390	746	0	0	
Dec 1991 Reserve		(7,851,432)										
Dec 1992 Reserve		(8,434,030)										
Average	SG	(8,142,731)	(121,841)	(2,439,197)	0	(3,917,992)	(494,409)	(1,168,934)	(357)	0	0	
Postmerger												
Dec 1991 Plant		4,284,960										
Dec 1992 Plant		3,485,613										
Average	SG	3,885,287	58,136	1,163,858	0	1,869,462	235,906	557,754	171	0	0	
Dec 1991 Reserve		(129,394)										
Dec 1992 Reserve		(240,609)										
Average	SG	(185,002)	(2,768)	(55,418)	0	(89,016)	(11,233)	(26,558)	0	0	0	
Net Plant		12,564,143	188,000	3,763,653	0	6,045,418	762,868	1,803,652	551	0	0	

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Division Net Plant Nuclear Pacific Power	**DNPPNP**	100.0000%	1.4963%	29.9555%	0.0000%	48.1164%	6.0718%	14.3556%	0.0044%	0.0000%	0.0000%	
Division Net Plant Nuclear Rocky Mountain Power	**DNPPNP**	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.00%	0.00%	0.00%	0.00%	
System Net Nuclear Plant	**SNNP**	100.0000%	1.4963%	29.9555%	0.0000%	48.1164%	6.0718%	14.3556%	0.0044%	0.0000%	0.0000%	

Account 182.22			**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**
Pre-merger	(101)	SG	17,094,202	255,784	5,120,656	0	8,225,121	1,037,924	2,453,967	750	0	0
	(108)	SG	(8,434,030)	(126,200)	(2,526,457)	0	(4,058,155)	(512,096)	(1,210,752)	(370)	0	0
Post-merger	(101)	SG	3,485,613	52,156	1,044,133	0	1,677,153	211,639	500,379	153	0	0
	(108)	SG	(240,609)	(3,600)	(72,076)	0	(115,772)	(14,609)	(34,541)	(11)	0	0
	(107)	SG	1,778,549	26,613	532,773	0	855,774	107,990	255,321	78	0	0
	(120)	SE	1,975,759	26,477	568,060	0	949,939	127,464	303,715	105	0	0
	(228)	SG	7,220,849	108,047	2,163,042	0	3,474,415	438,435	1,036,593	317	0	0
	(228)	SG	1,472,376	22,031	441,058	0	708,455	89,400	211,368	65	0	0
	(228)	SNNP	3,531,000	52,835	1,057,729	0	1,698,991	214,395	506,895	155	0	0
	(228)	SE	1,743,025	23,358	501,145	0	838,041	112,449	267,939	92	0	0
Total Acct 182.22			29,626,734	437,501	8,830,064	0	14,253,963	1,812,988	4,290,884	1,334	0	0
Revised Study	(228)	SNNP	112,680	1,686	33,754	0	54,218	6,842	16,176	5	0	0
	(228)	SE	941,950	12,623	270,824	0	452,887	60,769	144,797	50	0	0
December 1993 Adj.			1,054,630	14,309	304,578	0	507,104	67,610	160,973	55	0	0
Adjusted Acct 182.22			30,681,364	451,810	9,134,642	0	14,761,067	1,880,599	4,451,857	1,389	0	0
TROJP			100.0000%	1.4726%	29.7726%	0.0000%	48.1109%	6.1294%	14.5100%	0	0	0
Trojan Plant Allocator												

Account 228.42		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**
Plant - Premerger	SG	7,220,849	108,047	2,163,042	0	3,474,415	438,435	1,036,593	317	0	0
- Postmerger	SG	1,472,376	22,031	441,058	0	708,455	89,400	211,368	65	0	0
Storage Facility	SE	1,743,025	23,358	501,145	0	838,041	112,449	267,939	92	0	0
Transition Costs	SNNP	3,531,000	52,835	1,057,729	0	1,698,991	214,395	506,895	155	0	0
Total Acct 228.42		13,967,250	206,272	4,162,974	0	6,719,903	854,678	2,022,794	629	0	0
Transition Costs	SNNP	112,680	1,686	33,754	0	54,218	6,842	16,176	5	0	0
Storage Facility	SE	941,950	12,623	270,824	0	452,887	60,769	144,797	50	0	0
December 1993 Adj.		1,054,630	14,309	304,578	0	507,104	67,610	160,973	55	0	0
Adjusted Acct 228.42		15,021,880	220,581	4,467,553	0	7,227,007	922,288	2,183,768	684	0	0
TROJD		100.0000%	1.4684%	29.7403%	0.0000%	48.1099%	6.1396%	14.5372%	0.0046%	0.0000%	0.0000%
Trojan Decommissioning Allocator											

SCHMA		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**
Amortization Expense :											
Amortization of Limited Term Plant	Acct 404	8,477,382	123,860	2,552,047	0	4,058,018	500,111	1,242,986	361	0	0
Amortization of Other Electric Plant	Acct 405	0	0	0	0	0	0	0	0	0	0
Amortization of Plant Acquisitions	Acct 406	376,987	1,127	22,572	0	337,892	4,575	10,817	3	0	0
Amort of Prop. Losses, Unrecovered Plant, etc.	Acct 407	12,915,695	4,933,002	(2,525,354)	0	8,588,034	957,008	6,845,173	627	(5,882,796)	0
Total Amortization Expense :		21,770,064	5,057,989	49,265	0	12,983,944	1,461,695	8,098,976	992	(5,882,796)	0
Schedule M Amortization Factor		100.0000%	23.2337%	0.2263%	0.0000%	59.6413%	6.7142%	37.2024%	0.0046%	-27.0224%	0.0000%

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DESCRIPTION SCHMD	2020 PROTOCOL FACTOR	TOTAL	California California	Oregon Oregon	Washington Washington	Utah Utah	Idaho Idaho	Wyoming Wyoming	FERC-UPL FERC	OTHER OTHER	NON-UTILITY NON-UTILITY	Page Ref.
Depreciation Expense :												
Steam	Acct 403.1	314,798,531	4,710,392	94,299,508	0	151,469,846	19,113,897	45,191,071	13,818	0	0	
Nuclear	Acct 403.2	0	0	0	0	0	0	0	0	0	0	
Hydro	Acct 403.3	46,427,073	694,697	13,907,467	0	22,339,054	2,818,953	6,664,863	2,038	0	0	
Other	Acct 403.4	62,470,454	934,758	18,713,344	0	30,058,558	3,793,073	8,967,979	2,742	0	0	
Transmission	Acct 403.5	211,773,291	3,168,805	63,437,771	0	101,897,768	12,858,423	30,401,227	9,296	0	0	
Distribution	Acct 403.6	283,563,923	23,391,634	78,529,063	0	136,816,095	14,520,524	30,306,607	0	0	0	
General	Acct 403.7&8	84,821,640	2,572,690	25,665,500	0	40,749,541	4,940,714	10,891,002	2,194	0	0	
Mining	Acct 403.9	0	0	0	0	0	0	0	0	0	0	
Experimental	Acct 403.4	0	0	0	0	0	0	0	0	0	0	
Postmerger Hydro Step I Adjustment		0	0	0	0	0	0	0	0	0	0	
Total Depreciation Expense :		1,003,854,911	35,472,977	294,552,652	0	483,330,862	58,045,583	132,422,749	30,087	0	0	
Schedule M Depreciation Factor		100.0000%	3.5337%	29.3422%	0.0000%	48.1475%	5.7823%	13.1914%	0.0030%	0.0000%	0.0000%	
TAXDEPR		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Jurisdictional Tax Depreciation - 12/31/2027 - TOTAL		(1,431,853,591)	(56,278,155)	(425,048,378)	0	(692,830,661)	(80,765,345)	(176,773,541)	(43,826)	(113,685)	0	
									0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - CA	S	(38,739,111)	(38,739,111)	0	0	0	0	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - ID	S	(18,263,226)	0	0	0	0	(18,263,226)	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - OTHER	S	(113,685)	0	0	0	0	0	0	0	(113,685)	0	
Jurisdictional Tax Depreciation - 12/31/2027 - OR	S	(114,951,077)	0	(114,951,077)	0	0	0	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - SG	SG	(799,561,934)	(11,964,003)	(239,512,862)	0	(384,720,736)	(48,547,698)	(114,781,539)	(35,096)	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - SG-CAGE	SG	(83,605,361)	(1,251,003)	(25,044,413)	0	(40,227,923)	(5,076,340)	(12,002,012)	(3,670)	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - SG-CAGW	SG	(32,755,985)	(490,134)	(9,812,223)	0	(15,761,014)	(1,988,874)	(4,702,303)	(1,438)	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - SO	SO	(119,025,789)	(3,833,903)	(35,727,803)	0	(56,988,495)	(6,889,207)	(15,582,758)	(3,623)	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - UT	S	(195,132,493)	0	0	0	(195,132,493)	0	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - WA	S	0	0	0	0	0	0	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - WY	S	(29,704,930)	0	0	0	0	0	(29,704,930)	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2027 - TOTAL		(1,431,853,591)	(56,278,155)	(425,048,378)	0	(692,830,661)	(80,765,345)	(176,773,541)	(43,826)	(113,685)	0	
Current Total M Difference		(1,431,853,591)	(56,278,155)	(425,048,378)	0	(692,830,661)	(80,765,345)	(176,773,541)	(43,826)	(113,685)	0	
Tax Depr factor		100.0000%	3.9304%	29.6852%	0.0000%	48.3870%	5.6406%	12.3458%	0.0031%	0.0079%	0.0000%	

Pro Forma Factors December 31, 2027
Oregon General Rate Case - December 2027
COINCIDENTAL PEAKS - Post-Service Area Transfer

FORECAST LOADS (CP)

			Non-FERC					FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-27	12	8	154	2,904	-	3,872	499	1,231	32	8,692
Feb-27	22	8	136	2,704	-	3,858	498	1,242	27	8,464
Mar-27	2	7	125	2,583	-	3,656	427	1,203	35	8,029
Apr-27	13	7	125	2,415	-	3,338	412	1,115	32	7,436
May-27	28	17	113	2,123	-	4,200	579	1,071	33	8,118
Jun-27	25	16	128	2,378	-	5,205	745	1,199	34	9,688
Jul-27	19	17	144	2,887	-	5,716	776	1,171	-	10,694
Aug-27	16	16	132	2,742	-	5,589	620	1,209	-	10,291
Sep-27	7	17	110	2,223	-	4,965	567	1,162	-	9,027
Oct-27	14	18	94	2,153	-	3,909	439	1,141	-	7,736
Nov-27	16	18	116	2,551	-	4,084	459	1,188	-	8,397
Dec-27	21	18	133	2,780	-	4,243	493	1,217	-	8,866
			1,509	30,441	-	52,636	6,513	14,148	192	105,439

- (less)

Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)

			Non-FERC					FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-27	12	8	-	65	-	237	16	41	30	388
Feb-27	22	8	-	65	-	245	16	41	26	392
Mar-27	2	7	-	65	-	244	16	41	34	398
Apr-27	13	7	-	65	-	242	16	41	32	394
May-27	28	17	-	65	-	785	16	41	33	939
Jun-27	25	16	-	93	-	884	193	41	34	1,246
Jul-27	19	17	-	93	-	886	193	41	-	1,214
Aug-27	16	16	-	93	-	893	193	41	-	1,220
Sep-27	7	17	-	65	-	791	16	41	-	912
Oct-27	14	18	-	65	-	249	16	41	-	370
Nov-27	16	18	-	65	-	237	16	41	-	359
Dec-27	21	18	-	65	-	237	16	41	-	358
			-	862	-	5,930	720	490	188	8,190

= equals

COINCIDENTAL PEAK SERVED FROM COMPANY RESOURCES

			Non-FERC					FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-27	12	8	154	2,839	-	3,636	483	1,190	1	8,303
Feb-27	22	8	136	2,639	-	3,613	483	1,201	1	8,072
Mar-27	2	7	125	2,518	-	3,412	412	1,163	1	7,630
Apr-27	13	7	125	2,350	-	3,097	396	1,074	0	7,042
May-27	28	17	113	2,058	-	3,415	563	1,030	0	7,179
Jun-27	25	16	128	2,284	-	4,320	551	1,158	0	8,442
Jul-27	19	17	144	2,794	-	4,830	583	1,130	-	9,480
Aug-27	16	16	132	2,648	-	4,696	426	1,168	-	9,071
Sep-27	7	17	110	2,158	-	4,174	551	1,121	-	8,115
Oct-27	14	18	94	2,088	-	3,660	424	1,100	-	7,366
Nov-27	16	18	116	2,486	-	3,847	443	1,147	-	8,038
Dec-27	21	18	133	2,715	-	4,007	478	1,176	-	8,509
			1,509	29,579	-	46,707	5,793	13,657	4	97,248

+ plus

Adjustments for Ancillary Services Contracts including Reserves and Direct Access (Additions to Load)

			Non-FERC					FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-27	12	8	-	-	-	30	-	-	-	30
Feb-27	22	8	-	-	-	26	-	-	-	26
Mar-27	2	7	-	-	-	34	-	-	-	34
Apr-27	13	7	-	-	-	32	-	-	-	32
May-27	28	17	-	-	-	33	-	-	-	33
Jun-27	25	16	-	-	-	34	-	-	-	34
Jul-27	19	17	-	-	-	-	-	-	-	-
Aug-27	16	16	-	-	-	-	-	-	-	-
Sep-27	7	17	-	-	-	-	-	-	-	-
Oct-27	14	18	-	-	-	-	-	-	-	-
Nov-27	16	18	-	-	-	-	-	-	-	-
Dec-27	21	18	-	-	-	-	-	-	-	-
			-	-	-	188	-	-	-	188

= equals

LOADS FOR JURISDICTIONAL ALLOCATION (CP)

			Non-FERC					FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-27	12	8	154	2,839	-	3,666	483	1,190	1	8,334
Feb-27	22	8	136	2,639	-	3,639	483	1,201	1	8,098
Mar-27	2	7	125	2,518	-	3,446	412	1,163	1	7,664
Apr-27	13	7	125	2,350	-	3,128	396	1,074	0	7,074
May-27	28	17	113	2,058	-	3,447	563	1,030	0	7,211
Jun-27	25	16	128	2,284	-	4,354	551	1,158	0	8,476
Jul-27	19	17	144	2,794	-	4,830	583	1,130	-	9,480
Aug-27	16	16	132	2,648	-	4,696	426	1,168	-	9,071
Sep-27	7	17	110	2,158	-	4,174	551	1,121	-	8,115
Oct-27	14	18	94	2,088	-	3,660	424	1,100	-	7,366
Nov-27	16	18	116	2,486	-	3,847	443	1,147	-	8,038
Dec-27	21	18	133	2,715	-	4,007	478	1,176	-	8,509
			1,509	29,579	-	46,895	5,793	13,657	4	97,436

Pro Forma Factors December 31, 2027
Oregon General Rate Case - December 2027
ENERGY - Post-Service Area Transfer

FORECAST LOADS (MWH)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2027	1	75,380	1,577,690	-	2,607,580	318,620	836,780.00	25,538	5,441,588
2027	2	64,990	1,388,550	-	2,290,910	282,710	758,240.00	22,396	4,807,796
2027	3	65,570	1,437,600	-	2,386,120	265,940	800,680.00	25,325	4,981,235
2027	4	62,050	1,345,540	-	2,280,730	275,920	759,820.00	23,659	4,747,719
2027	5	67,560	1,358,960	-	2,393,490	331,690	771,520.00	24,005	4,947,225
2027	6	71,400	1,386,470	-	2,683,690	393,150	767,370.00	21,518	5,323,598
2027	7	79,900	1,610,990	-	3,125,740	506,890	802,680.00	-	6,126,200
2027	8	75,320	1,580,940	-	3,086,990	404,980	807,180.00	-	5,955,410
2027	9	63,030	1,404,090	-	2,557,480	313,770	754,630.00	-	5,093,000
2027	10	58,460	1,394,050	-	2,401,430	273,950	776,720.00	-	4,904,610
2027	11	63,620	1,485,980	-	2,414,550	270,770	772,990.00	-	5,007,910
2027	12	74,660	1,663,630	-	2,630,870	318,510	819,740.00	-	5,507,410
		821,940	17,634,490	-	30,859,580	3,956,900	9,428,350	142,441	62,843,701

- (less)

Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2027	1	-	-	-	59,556	-	-	24,413	83,969
2027	2	-	-	-	81,033	-	-	21,460	102,494
2027	3	-	-	-	111,368	-	-	24,328	135,696
2027	4	-	-	-	112,109	-	-	23,600	135,709
2027	5	-	-	-	141,315	-	-	23,947	165,262
2027	6	-	-	-	193,723	-	-	21,445	215,168
2027	7	-	-	-	245,302	-	-	-	245,302
2027	8	-	-	-	189,443	-	-	-	189,443
2027	9	-	-	-	148,617	-	-	-	148,617
2027	10	-	-	-	106,221	-	-	-	106,221
2027	11	-	-	-	72,507	-	-	-	72,507
2027	12	-	-	-	48,278	-	-	-	48,278
		-	-	-	1,509,474	-	-	139,194	1,648,667

= equals

LOADS SERVED FROM COMPANY RESOURCES (NPC)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2027	1	75,380	1,577,690	-	2,548,024	318,620	836,780	1,125	5,357,619
2027	2	64,990	1,388,550	-	2,209,877	282,710	758,240	935	4,705,302
2027	3	65,570	1,437,600	-	2,274,752	265,940	800,680	997	4,845,539
2027	4	62,050	1,345,540	-	2,168,621	275,920	759,820	59	4,612,010
2027	5	67,560	1,358,960	-	2,252,175	331,690	771,520	58	4,781,962
2027	6	71,400	1,386,470	-	2,489,967	393,150	767,370	72	5,108,429
2027	7	79,900	1,610,990	-	2,880,438	506,890	802,680	-	5,880,898
2027	8	75,320	1,580,940	-	2,897,547	404,980	807,180	-	5,765,967
2027	9	63,030	1,404,090	-	2,408,863	313,770	754,630	-	4,944,383
2027	10	58,460	1,394,050	-	2,295,209	273,950	776,720	-	4,798,389
2027	11	63,620	1,485,980	-	2,342,043	270,770	772,990	-	4,935,403
2027	12	74,660	1,663,630	-	2,582,592	318,510	819,740	-	5,459,132
		821,940	17,634,490	-	29,350,106	3,956,900	9,428,350	3,247	61,195,033

+ plus

Add: Resolute NTUA (UT) - Grossed up for Line Losses

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2027	1	-	-	-	24,413	-	-	-	24,413
2027	2	-	-	-	21,460	-	-	-	21,460
2027	3	-	-	-	24,328	-	-	-	24,328
2027	4	-	-	-	23,600	-	-	-	23,600
2027	5	-	-	-	23,947	-	-	-	23,947
2027	6	-	-	-	21,445	-	-	-	21,445
2027	7	-	-	-	-	-	-	-	-
2027	8	-	-	-	-	-	-	-	-
2027	9	-	-	-	-	-	-	-	-
2027	10	-	-	-	-	-	-	-	-
2027	11	-	-	-	-	-	-	-	-
2027	12	-	-	-	-	-	-	-	-
		-	-	-	139,194	-	-	-	139,194

= equals

LOADS FOR JURISDICTIONAL ALLOCATION (MWh)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2027	1	75,380	1,577,690	-	2,572,437	318,620	836,780	1,125	5,382,032
2027	2	64,990	1,388,550	-	2,231,337	282,710	758,240	935	4,726,763
2027	3	65,570	1,437,600	-	2,299,080	265,940	800,680	997	4,869,867
2027	4	62,050	1,345,540	-	2,192,221	275,920	759,820	59	4,635,610
2027	5	67,560	1,358,960	-	2,276,122	331,690	771,520	58	4,805,910
2027	6	71,400	1,386,470	-	2,511,412	393,150	767,370	72	5,129,874
2027	7	79,900	1,610,990	-	2,880,438	506,890	802,680	-	5,880,898
2027	8	75,320	1,580,940	-	2,897,547	404,980	807,180	-	5,765,967
2027	9	63,030	1,404,090	-	2,408,863	313,770	754,630	-	4,944,383
2027	10	58,460	1,394,050	-	2,295,209	273,950	776,720	-	4,798,389
2027	11	63,620	1,485,980	-	2,342,043	270,770	772,990	-	4,935,403
2027	12	74,660	1,663,630	-	2,582,592	318,510	819,740	-	5,459,132
		821,940	17,634,490	-	29,489,300	3,956,900	9,428,350	3,247	61,334,227

Pro Forma Factors December 31, 2027
Oregon General Rate Case - December 2027
Post-Service Area Transfer

	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC		
Subtotal	821,940	17,634,490	0	29,489,300	3,956,900	9,428,350	3,247	**61,334,227**	**Ref Page 4.12**
System Energy Factor	1.340%	28.751%	0.000%	48.080%	6.451%	15.3721%	0.005%	100.00%	
Divisional Energy - Pacific	3.088%	66.253%	0.000%	0.000%	0.000%	30.6591%	0.000%	100.00%	
Divisional Energy - Utah	0.000%	0.000%	0.000%	84.941%	11.397%	3.6519%	0.009%	100.00%	
System Generation Factor	1.496%	29.956%	0.000%	48.116%	6.072%	14.3556%	0.004%	100.00%	
Divisional Generation - Pacific	3.411%	68.286%	0.000%	0.000%	0.000%	28.3030%	0.000%	100.00%	
Divisional Generation - Utah	0.000%	0.000%	0.000%	85.720%	10.817%	3.4556%	0.008%	100.00%	
System Capacity (kw)									
Accord	1,509	29,579	0	46,895	5,793	13,657.3	4	**97,436**	**Ref Page 4.11**
Modified Accord	1,509	29,579	0	46,895	5,793	13,657.3	4	**97,436**	**Ref Page 4.11**
Rolled-In	1,509	29,579	0	46,895	5,793	13,657.3	4	**97,436**	**Ref Page 4.11**
Rolled-In with Hydro Adj.	1,509	29,579	0	46,895	5,793	13,657.3	4	**97,436**	**Ref Page 4.11**
Rolled-In with Off-Sys Adj.	1,509	29,579	0	46,895	5,793	13,657.3	4	**97,436**	**Ref Page 4.11**
System Capacity Factor									
Accord	1.548%	30.357%	0.000%	48.129%	5.945%	14.0167%	0.004%	100.00%	
Modified Accord	1.548%	30.357%	0.000%	48.129%	5.945%	14.0167%	0.004%	100.00%	
Rolled-In	1.548%	30.357%	0.000%	48.129%	5.945%	14.0167%	0.004%	100.00%	
Rolled-In with Hydro Adj.	1.548%	30.357%	0.000%	48.129%	5.945%	14.0167%	0.004%	100.00%	
Rolled-In with Off-Sys Adj.	1.548%	30.357%	0.000%	48.129%	5.945%	14.0167%	0.004%	100.00%	
System Energy (kwh)									
Accord	821,940	17,634,490	0	29,489,300	3,956,900	9,428,350	3,247	61,334,227	
Modified Accord	821,940	17,634,490	0	29,489,300	3,956,900	9,428,350	3,247	61,334,227	
Rolled-In	821,940	17,634,490	0	29,489,300	3,956,900	9,428,350	3,247	61,334,227	
Rolled-In with Hydro Adj.	821,940	17,634,490	0	29,489,300	3,956,900	9,428,350	3,247	61,334,227	
Rolled-In with Off-Sys Adj.	821,940	17,634,490	0	29,489,300	3,956,900	9,428,350	3,247	61,334,227	
System Energy Factor									
Accord	1.340%	28.751%	0.000%	48.080%	6.451%	15.3721%	0.005%	100.00%	
Modified Accord	1.340%	28.751%	0.000%	48.080%	6.451%	15.3721%	0.005%	100.00%	
Rolled-In	1.340%	28.751%	0.000%	48.080%	6.451%	15.3721%	0.005%	100.00%	
Rolled-In with Hydro Adj.	1.340%	28.751%	0.000%	48.080%	6.451%	15.3721%	0.005%	100.00%	
Rolled-In with Off-Sys Adj.	1.340%	28.751%	0.000%	48.080%	6.451%	15.3721%	0.005%	100.00%	
System Generation Factor									
Accord	1.496%	29.956%	0.000%	48.116%	6.072%	14.3556%	0.004%	100.00%	
Modified Accord	1.496%	29.956%	0.000%	48.116%	6.072%	14.3556%	0.004%	100.00%	
Rolled-In	1.496%	29.956%	0.000%	48.116%	6.072%	14.3556%	0.004%	100.00%	
Rolled-In with Hydro Adj.	1.496%	29.956%	0.000%	48.116%	6.072%	14.3556%	0.004%	100.00%	
Rolled-In with Off-Sys Adj.	1.496%	29.956%	0.000%	48.116%	6.072%	14.3556%	0.004%	100.00%	

REDACTED
Docket No. UE 470
Exhibit PAC/804
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Shelley E. McCoy

PacifiCorp's Property Tax Estimation Procedure

May 2026

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

REDACTED
Docket No. UE 470
Exhibit PAC/805
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Shelley E. McCoy

S&P Market Intelligence Power Planner Data

May 2026

REDACTED

PacifiCorp
Oregon General Rate Case - December 2027
S&P Market Intelligence Power Planner Data
Fourth Quarter 2025 Forecast
Release Date : January 23, 2026

Calendar Years	Escalation Factors and Percentage Increases June	December	FERC Accts
[redacted]			500 - 507
			510 - 514
			535 - 540
			541 - 545
			546 - 550; 556 - 559
			551 - 554
			560 - 567
			568 - 573
			580 - 589
			590 - 598
			901 - 903, 905
			907 - 910
			911 - 916
			920, 922, 929
			921
			923
			924
			925
			926
			927
			928
			930.1
			930.2
			931
			935

REDACTED
Docket No. UE 470
Exhibit PAC/806
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Shelley E. McCoy

REC Revenues Adjustment Support

May 2026

PacifiCorp
Oregon General Rate Case - December 2027
Confidential REC Revenues

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Remove June 2025 Booked Revenues (Including Accruals)	456	1	(17,823,609)	SG	27.756%	(4,947,045)	3.2.1
Remove June 2025 REC Deferrals	456	1	6,179,888	SG	27.756%	1,715,263	3.2.1
Remove June 2025Leaning Juniper Indemnity	456	1	16,440	SG	27.756%	4,563	3.2.1
Add December 2027 Forecasted REC Revenues	456	3	[redacted]	SG	27.756%	[redacted]	3.2.2

Description of Adjustment:

This adjustment removes REC revenue and REC deferrals booked during the 12 months ended June 2025. Most of Oregon's share of the renewable energy credits (RECs) are banked for compliance; however, not all RECs meet the Oregon RPS qualifications. Oregon's revenues from RPS ineligible RECs that are sold are passed backed to customers through the Oregon property sales balancing account per Commission Order No. 10-210 in Docket UP 260. REC revenues received through Schedule 272 are added back into Test Year results on a forecast basis.

PacifiCorp
Oregon General Rate Case - December 2027
Confidential REC Revenues
Actuals as Booked

Posting Date	Fin Accrual	Fin Reversal	Back Office Actual	Kennecott Removal	NET Rec Revenue
FERC Acct (Ref B1)	4562700	4562700	4562700	4562700	
SAP Acct	301944	301944	301945	301945	
July-24	(600,296)	51,398	(50,000)	50,000	(548,898)
August-24	(175,283)	600,296	(598,700)	50,000	(123,687)
September-24	(2,582,070)	1,404,818	(50,000)	50,000	(1,177,251)
October-24	(2,970,748)	2,837,909	(1,227,500)	50,000	(1,310,339)
November-24	(4,101,933)	1,485,374	(1,360,288)	50,000	(3,926,847)
December-24	(798,066)	4,101,933	(4,100,272)	50,000	(746,404)
January-25	(1,737,922)	798,066	(796,525)	50,000	(1,686,381)
February-25	(2,753,359)	1,737,922	(1,737,525)	50,000	(2,702,961)
March-25	(1,355,877)	2,753,359	(2,750,750)	50,000	(1,303,268)
April-25	(2,962,486)	1,355,877	(1,352,500)	50,000	(2,909,109)
May-25	(592,657)	2,962,486	(2,958,750)	50,000	(538,921)
June-25	(904,697)	592,657	(587,500)	50,000	(849,539)
12 ME June 2025 Total	(21,535,394)	20,682,095	(17,570,310)	600,000	(17,823,609)

REC Deferrals Included in Unadjusted Results:

FERC Account 4562700
Amount Yr. Ended June 2025 **6,179,888** **Ref. 3.2**

Leaning Juniper indemnity REC revenue included in unadjusted results:

FERC Account 4562700
Amount Yr. Ended June 2025 **16,440** **Ref. 3.2**

REDACTED

PacifiCorp
Oregon General Rate Case - December 2027
Confidential REC Revenues
Pryor Mountain REC Revenue
Calendar Year 2027 Forecast

Posting Date	Pryor Mountain Forecast
January-27	
February-27	
March-27	
April-27	
May-27	
June-27	
July-27	
August-27	
September-27	
October-27	
November-27	
December-27	
12 ME December 2027 Total	**Ref. 3.2**

REDACTED
Docket No. UE 470
Exhibit PAC/807
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Bridger Mine Reclamation and Decommissioning Costs Support

May 2026

PacifiCorp
Oregon General Rate Case - December 2027
Confidential Bridger Mine Reclamation Costs and Decommissioning Cost

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Bridger Reclamation Costs	501	3	[redacted]	SE	26.823%	[redacted]	6.4.1
Annual Incremental Decomm. Costs	407	3	12,974,220	SG	27.756%	3,601,069	6.4.2
Adjustment to Rate Base							
Bridger Reclamation Costs	254	3	[redacted]	OR	Situs	[redacted]	6.4.1
Remove Base Accum. Reg Liab. - Incr. Decomm.	108SP	3	1,070,726	OR	Situs	1,070,726	B-17
Remove Base Accum. Reg Liab. - Incr. Closure	254	3	673,279	OR	Situs	673,279	B-15
Accum. Reg Liab.-Incr. Decomm. & Closure	254	3	(32,435,550)	SG	27.756%	(9,002,673)	6.4.2
Adjustment to Tax:							
Sch M Adj. - Bridger Reclamation	SCHMAT	3	[redacted]	SE	26.823%	[redacted]	6.4.1
DIT Expense	41110	3	[redacted]	SE	26.823%	[redacted]	6.4.1
Accum. DIT Balance	190	3	[redacted]	OR	Situs	[redacted]	6.4.1
Sch M Adj. - Incr. Decomm. & Clos.	SCHMAT	3	12,974,220	SG	27.756%	3,601,069	6.4.2
DIT Expense	41110	3	(3,189,924)	SG	27.756%	(885,382)	6.4.2
Accum. DIT Balance	190	3	7,974,810	SG	27.756%	2,213,454	6.4.2
Remove Base Sch M Adj. - Steam Decomm.	SCHMAT	3	(1,070,726)	OR	Situs	(1,070,726)	
Remove Base DIT Expense	41110	3	263,255	OR	Situs	263,255	
Remove Base Accum. DIT Balance	190	3	(263,255)	OR	Situs	(263,255)	
Remove Base Sch M Adj. - Bridger Reclamation	SCHMAT	3	[redacted]	OR	Situs	[redacted]	
Remove Base DIT Expense	41110	3	[redacted]	OR	Situs	[redacted]	
Remove Base Sch M Adj. - Other Plant Closure	SCHMAT	3	(673,279)	OR	Situs	(673,279)	
Remove Base DIT Expense	41110	3	165,536	OR	Situs	165,536	
Remove Base Accum. DIT Balance	190	3	(165,536)	OR	Situs	(165,536)	

Description of Adjustment:

This adjustment includes into test period results Bridger Mine reclamation costs which were also included in Dockets UE-374, UE-399, and UE-433. The reclamation costs were originally included in Docket UE-374 to be collected over a five year period from 2021 - 2025. In Docket UE-433 the Company was ordered to extend the depreciable life of the Jim Bridger coal units through 2028. Accordingly, the estimated reclamation costs for the Jim Bridger Mine have been recalibrated to reflect on-going operations through 2028 and the updated reclamation costs are spread through 2028. The adjustment reflects the reclamation costs collected since approval in 2021. The regulatory liability balance is included on a 13-month-average basis for the year ending December 2027.
This adjustment also includes the incremental decommissioning and other plant closure costs for Jim Bridger Units 3 & 4 and Dave Johnston Unit 4, to be recovered over a 12 year period per Order No. 24-447 in Docket UE-433.

REDACTED

PacifiCorp
Oregon General Rate Case - December 2027
Confidential Bridger Mine Reclamation Costs and Decommissioning Cost

Amount Used in Dockets UE-374, UE-399, UE-433

Annual Incremental Contribution for Reclamation	[redacted]
Incremental Depreciation Expense Prior to Reclamation	[redacted]
Years from 2021 to 2025	5
Annual Incremental Depreciation Expense	[redacted]
Currently Approved Annual Amount	[redacted]
Total Amount Collected from January 2021 - March 2027	[redacted] See Below

Proposed Update in Amounts Due to Operating the Bridger Mine Through 2028:

Total Contribution for Reclamation	[redacted]
Incremental Depreciation Expense Prior to Reclamation	[redacted]
Less approved amounts collected through March 2027	[redacted] See Above
Net Amount to be collected assuming Operation of Mine through Dec 2028	[redacted]
Months to End of Depreciable Life (April 2027 to Dec 2028)	21
Net Monthly Amortization	[redacted] See Below

	TOTAL COMPANY						
	Previous 501 Mthly Accum.	New 501 Mthly Accum.	Net 501 Mthly Accum.	SCHMAT Tax	41110 Def Inc Tax Exp	254 Reg. Liab.	190 ADIT
Jun-25	[redacted]						
Jul-25							
Aug-25							
Sep-25							
Oct-25							
Nov-25							
Dec-25							
Jan-26							
Feb-26							
Mar-26							
Apr-26							
May-26							
Jun-26							
Jul-26							
Aug-26							
Sep-26							
Oct-26							
Nov-26							
Dec-26							
Jan-27							
Feb-27							
Mar-27							
Apr-27							
May-27							
Jun-27							
Jul-27							
Aug-27							
Sep-27							
Oct-27							
Nov-27							
Dec-27							
Annual Total	[redacted]		[redacted]	[redacted]	[redacted]		
			Ref 6.4_CONF	Ref 6.4_CONF	Ref 6.4_CONF		

13 Mo. Avg. - Total Company	[redacted]	[redacted]
13 Mo. Avg. - Oregon Allocated	[redacted]	[redacted]
EOP June 2025 Balance	[redacted]	[redacted]
Adjustment	[redacted]	[redacted]
	Ref 6.4_CONF	Ref 6.4_CONF

*Oregon 2027 SE Factor 26.823%

PacifiCorp
Oregon General Rate Case - December 2027
Confidential Bridger Mine Reclamation Costs and Decommissioning Cost
Incremental Decommissioning & Other Plant Closure Costs
2018 Depreciation Study

Plant	Plant Unit Closure Date	Recovery Period (Years)	Incremental Decommissioning Costs	Other Plant Closure Costs	Total Company Annual Amount
Dave Johnston Unit 4	2029	12.00	[redacted]	[redacted]	[redacted]
Jim Bridger Unit 3	2028	12.00	[redacted]	[redacted]	[redacted]
Jim Bridger Unit 4	2028	12.00	[redacted]	[redacted]	[redacted]
				Total	12,974,220
					Ref 6.4

	407 Mthly Accum.	SCHMAT Tax	41110 Def Inc Tax Exp	254 Reg. Liab.	190 ADIT
Jun-25	1,081,185	1,081,185	(265,827)	(6,487,110)	1,594,962
Jul-25	1,081,185	1,081,185	(265,827)	(7,568,295)	1,860,789
Aug-25	1,081,185	1,081,185	(265,827)	(8,649,480)	2,126,616
Sep-25	1,081,185	1,081,185	(265,827)	(9,730,665)	2,392,443
Oct-25	1,081,185	1,081,185	(265,827)	(10,811,850)	2,658,270
Nov-25	1,081,185	1,081,185	(265,827)	(11,893,035)	2,924,097
Dec-25	1,081,185	1,081,185	(265,827)	(12,974,220)	3,189,924
Jan-26	1,081,185	1,081,185	(265,827)	(14,055,405)	3,455,751
Feb-26	1,081,185	1,081,185	(265,827)	(15,136,590)	3,721,578
Mar-26	1,081,185	1,081,185	(265,827)	(16,217,775)	3,987,405
Apr-26	1,081,185	1,081,185	(265,827)	(17,298,960)	4,253,232
May-26	1,081,185	1,081,185	(265,827)	(18,380,145)	4,519,059
Jun-26	1,081,185	1,081,185	(265,827)	(19,461,330)	4,784,886
Jul-26	1,081,185	1,081,185	(265,827)	(20,542,515)	5,050,713
Aug-26	1,081,185	1,081,185	(265,827)	(21,623,700)	5,316,540
Sep-26	1,081,185	1,081,185	(265,827)	(22,704,885)	5,582,367
Oct-26	1,081,185	1,081,185	(265,827)	(23,786,070)	5,848,194
Nov-26	1,081,185	1,081,185	(265,827)	(24,867,255)	6,114,021
Dec-26	1,081,185	1,081,185	(265,827)	(25,948,440)	6,379,848
Jan-27	1,081,185	1,081,185	(265,827)	(27,029,625)	6,645,675
Feb-27	1,081,185	1,081,185	(265,827)	(28,110,810)	6,911,502
Mar-27	1,081,185	1,081,185	(265,827)	(29,191,995)	7,177,329
Apr-27	1,081,185	1,081,185	(265,827)	(30,273,180)	7,443,156
May-27	1,081,185	1,081,185	(265,827)	(31,354,365)	7,708,983
Jun-27	1,081,185	1,081,185	(265,827)	(32,435,550)	7,974,810
Jul-27	1,081,185	1,081,185	(265,827)	(33,516,735)	8,240,637
Aug-27	1,081,185	1,081,185	(265,827)	(34,597,920)	8,506,464
Sep-27	1,081,185	1,081,185	(265,827)	(35,679,105)	8,772,291
Oct-27	1,081,185	1,081,185	(265,827)	(36,760,290)	9,038,118
Nov-27	1,081,185	1,081,185	(265,827)	(37,841,475)	9,303,945
Dec-27	1,081,185	1,081,185	(265,827)	(38,922,660)	9,569,772
Annual Total	**12,974,220**	**12,974,220**	**(3,189,924)**		
		Ref 6.4	**Ref 6.4**		
		13 Mo. Avg. - Total Company		**(32,435,550)**	**7,974,810**
				Ref 6.4	**Ref 6.4**

REDACTED
Docket No. UE 470
Exhibit PAC/808
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Shelley E. McCoy

New Wind Generation Capital Additions Support

May 2026

PacifiCorp
Oregon General Rate Case - December 2027
Confidential New Wind Generation Capital Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
New Wind Capital - Wind	338WP	3	903,601,369	SG	27.756%	250,799,753	8.20.1
Adjustment to Depreciation Expense:							
New Wind Capital - Wind Depr. Exp	403WP	3	36,063,621	SG	27.756%	10,009,665	8.20.1
Adjustment to Depreciation Reserve:							
New Wind Capital - Wind Depr. Reserve	108WP	3	(61,446,217)	SG	27.756%	(17,054,751)	8.20.1
Adjustment to Operations & Maintenance Expense:							
Incremental Wind Repowering O&M Exp	558WP	3	8,985,433	SG	27.756%	2,493,958	8.20.2
Adjustment to Tax							
Schedule M Addition	SCHMAT	3	(951,806)	SG	27.756%	(264,179)	
Schedule M Deduction	SCHMDT	3	(13,999,344)	SG	27.756%	(3,885,598)	
DIT Expense	41110	3	234,017	SG	27.756%	64,953	
DIT Expense	41010	3	(3,441,963)	SG	27.756%	(955,337)	
ADIT	282	3	(1,652,442)	SG	27.756%	(458,645)	

Description of Adjustment:

This adjustment adds into the Test Period incremental capital additions related to certain confidential capital projects. Included in this adjustment is incremental operations and maintenance expense for these confidential projects.

PacifiCorp
Oregon General Rate Case - December 2027
Confidential New Wind Generation Capital Additions

NEW WIND CAPITAL ADDITIONS

Electric Plant in Service

	Account	Factor	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Month Avg Dec-27
Wind Plant Wind	338WP	SG	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369	903,601,369

Depreciation Expense*

	Account	Factor	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	CY 2027
Wind Plant Wind	403WP	SG	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	3,005,302	36,063,621

Depreciation Reserve

	Account	Factor	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	13 Month Avg Dec-27
Wind Plant Wind	108WP	SG	(43,414,406)	(46,419,708)	(49,425,010)	(52,430,312)	(55,435,613)	(58,440,915)	(61,446,217)	(64,451,519)	(67,456,821)	(70,462,122)	(73,467,424)	(76,472,726)	(79,478,028)	(61,446,217)

	EOP June 2025	13 Mo Average Dec 2027	Adjustment	
338WP	-	903,601,369	**903,601,369**	**Ref. 8.20**
403WP	-	36,063,621	**36,063,621**	**Ref. 8.20**
108WP	-	(61,446,217)	**(61,446,217)**	**Ref. 8.20**

*Composite Depreciation Rate - Wind

3.991% Composite Depreciation Rate - Wind

REDACTED

PacifiCorp
Oregon General Rate Case - December 2027
Confidential New Wind Generation Capital Additions

Project	Date	Project Capital Amount	Ref
New Wind			
WBUILD - RMP Rock Creek I 190 MW 2024	Various		
WBUILD - RMP Rock Creek Wind II 400MW 2025	Various		
		903,601,369	**Ref 8.21.1**

Project	2027 O&M	
WBUILD - RMP Rock Creek I 190 MW 2024		
WBUILD - RMP Rock Creek Wind II 400MW 2025		
	8,985,433	**Ref 8.21**

Docket No. UE 470
Exhibit PAC/809
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Proposed Amortization of Deferral Balances and Goodwill Value of Washington Service Area Transfer

May 2026

PacifiCorp
Oregon General Rate Case - December 2027
Summary of Proposed Deferral Amortizations

Docket	Deferral	Jun. 30, 2027 Balance	Amortization Period	Annual Amortization	
UM 2402	Costs Relating to Rock Creek I	2,484,568	1 Year	2,551,929	
UM 2430	Costs Associated with Completion of Rock Creek II Turbines	1,507,301	1 Year	1,604,044	
UM 2426	Costs Relating to the Renewable Adjustment Clause	5,066,033	3 Year	1,811,370	*
UM 2433	Costs Associated with Increased Insurance Premiums_WITH interim rates	1,495,520	1 Year	1,584,654	
UP 441	PacifiCorp Sale of Washington-Based Assets	(40,044,813)	3 Year	(14,318,103)	

*UM 2426 is applicable to residential customers only

PacifiCorp
Oregon General Rate Case - December 2027
UM 2404 - Rock Creek I Revenue Requirement Deferral
Amortization Schedule

Application Date: 8/15/2026

		Rev. Req. Deferral	Amortization	Interest[1,2]	Cumulative Balance
2025	August	250,646		773	251,419
	September	485,626		3,048	740,093
	October	485,626		6,062	1,231,781
	November	485,626		9,094	1,726,502
	December	485,626		12,145	2,224,273
2026	January	-		13,718	2,237,991
	February	-		13,802	2,251,793
	March	-		13,887	2,265,680
	April	-		13,973	2,279,653
	May	-		14,059	2,293,712
	June	-		14,146	2,307,858
	July	-		14,233	2,322,091
	August	-		14,321	2,336,412
	September	-		14,409	2,350,821
	October	-		14,498	2,365,319
	November	-		14,587	2,379,906
	December	-		14,677	2,394,584
2027	January	-		14,768	2,409,352
	February	-		14,859	2,424,211
	March	-		14,951	2,439,161
	April	-		15,043	2,454,204
	May	-		15,136	2,469,340
	June	-		15,229	2,484,568
	July	-	(106,330)	9,545	2,387,783
	August	-	(212,661)	9,173	2,184,295
	September	-	(212,661)	8,391	1,980,026
	October	-	(212,661)	7,607	1,774,972
	November	-	(212,661)	6,819	1,569,130
	December	-	(212,661)	6,028	1,362,497
2028	January	-	(212,661)	5,234	1,155,070
	February	-	(212,661)	4,437	946,847
	March	-	(212,661)	3,637	737,824
	April		(212,661)	2,834	527,997
	May		(212,661)	2,028	317,365
	June		(212,661)	1,219	105,923
	July		(106,330)	407	-
	Annual Amortization		**(2,551,929)**		

1. Interest rate through deferral period (WACC - UE-433): 7.40%
2. Interest rate through amortization period (2026 MBTR): 4.61%

PacifiCorp
Oregon General Rate Case - December 2027
UM 2402 - Rock Creek I Revenue Requirement Deferral
Revenue Requirement Summary

		Rock Creek I - In-Rates (UE-433)		
		Total Company	2025 Allocation %	Oregon Allocated
Revenue Requirement	**Factor**			
Capital Investment	SG	178,928,861	26.884%	48,103,516
Depreciation Reserve	SG	(313,744)	26.884%	(84,347)
Accumulated DIT Balance	SG	(6,521,739)	26.884%	(1,753,315)
Net Rate Base		172,093,379		46,265,854
Pre-Tax Rate of Return		8.950%		8.950%
Pre-Tax Return on Rate Base		15,401,521		4,140,569
Operation & Maintenance	SG	2,992,590	26.884%	804,533
Depreciation	SG	7,529,847	26.884%	2,024,336
Deferred Income Tax Expense	SG	-	26.884%	-
Property Tax	GPS	1,454,743	27.430%	399,029
Rev. Reqt. Before Gross-up		27,378,700		7,368,467
Franchise Taxes				173,645
Bad Debt Expense				43,851
Resource Supplier Tax				8,763
PUC Fee				34,331
Annual Rev. Reqt. (with Gross-up)				7,629,057
Monthly Rev. Reqt. (with Gross-up)				635,755

		Rock Creek I Deferral - 2025		
		Total Company	2025 Allocation %	Oregon Allocated
Revenue Requirement	**Factor**			
Capital Investment	SG	337,025,039	26.884%	90,606,341
Depreciation Reserve	SG	(6,596,206)	26.884%	(1,773,334)
Accumulated DIT Balance	SG	(17,064,269)	26.884%	(4,587,585)
Net Rate Base		313,364,564		84,245,421
Pre-Tax Rate of Return		8.950%		8.950%
Pre-Tax Return on Rate Base		28,044,605		7,539,556
Operation & Maintenance	SG	2,992,590	26.884%	804,533
Depreciation	SG	14,332,387	26.884%	3,853,141
Deferred Income Tax Expense	SG	-	26.884%	-
Property Tax	GPS	2,915,467	27.430%	799,699
Rev. Reqt. Before Gross-up		48,285,048		12,996,929
Franchise Taxes				306,286
Bad Debt Expense				77,347
Resource Supplier Tax				15,457
PUC Fee				60,555
Annual Rev. Reqt. (with Gross-up)				13,456,574
Monthly Rev. Reqt. (with Gross-up)				1,121,381
Monthly Rev. Req Deferral				485,626

PacifiCorp
Oregon General Rate Case - December 2027
UM2402 - Rock Creek I Revenue Requirement Deferral
Capital Investments and Expenses Summary

	Gross Plant In Service	Accumulated Depreciation	Accumulated Deferred Income Taxes
Dec-24	178,928,861	(313,744)	(6,521,739)
Jan-25	178,928,861	(941,231)	(7,716,095)
Feb-25	221,757,133	(1,643,816)	(8,891,988)
Mar-25	221,757,133	(2,421,498)	(10,049,417)
Apr-25	336,065,198	(3,399,614)	(12,541,723)
May-25	390,648,723	(4,673,873)	(14,961,217)
Jun-25	390,648,723	(6,043,843)	(17,357,179)
Jul-25	411,248,825	(7,449,934)	(19,306,730)
Aug-25	411,258,800	(8,892,164)	(21,247,396)
Sep-25	411,354,992	(10,334,579)	(23,188,016)
Oct-25	411,408,003	(11,777,257)	(24,935,381)
Nov-25	407,398,451	(13,212,997)	(26,684,452)
Dec-25	409,921,800	(14,646,131)	(28,434,164)
13-mo average	**337,025,039**	**(6,596,206)**	**(17,064,269)**

	Depreciation Expense	Operations & Maintenance	Property Tax
Dec-24	313,744		121,229
Jan-25	627,487	249,383	120,803
Feb-25	702,585	249,383	149,394
Mar-25	777,682	249,383	148,866
Apr-25	978,116	249,383	225,785
May-25	1,274,260	249,383	261,967
Jun-25	1,369,970	249,383	261,037
Jul-25	1,406,091	249,383	274,064
Aug-25	1,442,230	249,383	273,092
Sep-25	1,442,416	249,383	272,178
Oct-25	1,442,677	249,383	271,235
Nov-25	1,435,740	249,383	267,539
Dec-25	1,433,134	249,383	268,279
12-mo ending	**14,332,387**	**2,992,590**	**2,915,467**

Depreciation Rate *4.208%*

PacifiCorp
Oregon General Rate Case - December 2027
UM 2430 - Rock Creek II Revenue Requirement Deferral
Amortization Schedule

Application Date: 1/29/2026

		Rev. Req. Deferral	Adjustment[1]	Amortization	Interest[2,3]	Cumulative Balance
2026	January	11,131			34	11,166
	February	115,025			424	126,614
	March	115,025	(516,471)		1,136	(273,697)
	April	115,025			(1,333)	(160,006)
	May	115,025			(632)	(45,613)
	June	115,025			73	69,485
	July	115,025			783	185,293
	August	115,025			1,497	301,815
	September	115,025			2,216	419,056
	October	115,025			2,939	537,020
	November	115,025			3,667	655,711
	December	115,025			4,399	775,134
2027	January	115,025			5,135	895,294
	February	115,025			5,876	1,016,195
	March	115,025			6,622	1,137,841
	April	115,025			7,372	1,260,238
	May	115,025			8,127	1,383,390
	June	115,025			8,886	1,507,301
	July	57,512		(66,835)	5,773	1,503,750
	August	-		(133,670)	5,520	1,375,600
	September	-		(133,670)	5,028	1,246,958
	October	-		(133,670)	4,534	1,117,821
	November	-		(133,670)	4,038	988,188
	December	-		(133,670)	3,540	858,058
2028	January	-		(133,670)	3,040	727,427
	February	-		(133,670)	2,538	596,294
	March	-		(133,670)	2,034	464,658
	April	-		(133,670)	1,528	332,516
	May	-		(133,670)	1,021	199,867
	June	-		(133,670)	511	66,707
	July			(66,835)	128	(0)
	Annual Amortization			**(1,604,044)**		

1. Application of residual over-collected balance on Sch 203 per ADV 1833. Includes esitmated residual collections.
2. Interest rate through deferal period (WACC - UE-433): 7.40%
3. Interest rate through amortization period (2026 MBTR): 4.61%

PacifiCorp
Oregon General Rate Case - December 2027
UM 2430 - Rock Creek II Revenue Requirement Deferral
Revenue Requirement Summary

		Rock Creek II - RAC Compliance Filing		
		Total Company	2025 Allocation %	Oregon Allocated
Revenue Requirement	**Factor**			
Capital Investment	SG	836,704,110	26.884%	224,940,847
Depreciation Reserve	SG	(24,952,634)	26.884%	(6,708,305)
Accumulated DIT Balance	SG	(67,923,149)	26.884%	(18,260,566)
Net Rate Base		743,828,327		199,971,976
Pre-Tax Rate of Return		8.950%		8.950%
Pre-Tax Return on Rate Base		66,569,018		17,896,519
Operation & Maintenance	SG	5,733,393	26.884%	1,541,374
Depreciation	SG	35,210,942	26.884%	9,466,165
Deferred Income Tax Expense	SG	-	26.884%	-
Property Tax	GPS	6,599,416	27.430%	1,810,190
Rev. Reqt. Before Gross-up		114,112,769		30,714,249
Franchise Taxes				723,812
Bad Debt Expense				182,787
Resource Supplier Tax				36,528
PUC Fee				143,102
Annual Rev. Reqt. (with Gross-up)				31,800,477
Monthly Rev. Reqt. (with Gross-up)				2,650,040

		Rock Creek II - Actual In-Service		
		Total Company	2025 Allocation %	Oregon Allocated
Revenue Requirement	**Factor**			
Capital Investment	SG	874,783,601	26.884%	235,178,197
Depreciation Reserve	SG	(25,820,653)	26.884%	(6,941,665)
Accumulated DIT Balance	SG	(71,080,216)	26.884%	(19,109,317)
Net Rate Base		777,882,732		209,127,216
Pre-Tax Rate of Return		8.950%		8.950%
Pre-Tax Return on Rate Base		69,616,722		18,715,869
Operation & Maintenance	SG	5,733,393	26.884%	1,541,374
Depreciation	SG	36,813,438	26.884%	9,896,982
Deferred Income Tax Expense	SG	-	26.884%	-
Property Tax	GPS	6,901,943	27.430%	1,893,172
Rev. Reqt. Before Gross-up		119,065,496		32,047,398
Franchise Taxes				755,229
Bad Debt Expense				190,720
Resource Supplier Tax				38,114
PUC Fee				149,313
Annual Rev. Reqt. (with Gross-up)				33,180,774
Monthly Rev. Reqt. (with Gross-up)				2,765,064
Monthly Rev. Req Deferral				**115,025**

PacifiCorp
Oregon General Rate Case - December 2027
UM 2430 - Rock Creek II Revenue Requirement Deferral
Capital Investments and Expenses Summary

	Gross Plant In Service	Accumulated Depreciation	Accumulated Deferred Income Taxes
Dec-25	874,783,601	(7,413,934)	(41,193,076)
Jan-26	874,783,601	(10,481,720)	(46,174,266)
Feb-26	874,783,601	(13,549,507)	(51,155,456)
Mar-26	874,783,601	(16,617,293)	(56,136,646)
Apr-26	874,783,601	(19,685,080)	(61,117,836)
May-26	874,783,601	(22,752,866)	(66,099,026)
Jun-26	874,783,601	(25,820,653)	(71,080,216)
Jul-26	874,783,601	(28,888,439)	(76,061,406)
Aug-26	874,783,601	(31,956,226)	(81,042,596)
Sep-26	874,783,601	(35,024,012)	(86,023,786)
Oct-26	874,783,601	(38,091,799)	(91,004,976)
Nov-26	874,783,601	(41,159,585)	(95,986,166)
Dec-26	874,783,601	(44,227,372)	(100,967,356)
13-mo average	**874,783,601**	**(25,820,653)**	**(71,080,216)**

	Depreciation Expense	Operations & Maintenance	Property Tax
Jan-26	3,067,786	477,783	586,614
Feb-26	3,067,786	477,783	584,532
Mar-26	3,067,786	477,783	582,449
Apr-26	3,067,786	477,783	580,367
May-26	3,067,786	477,783	578,285
Jun-26	3,067,786	477,783	576,203
Jul-26	3,067,786	477,783	574,121
Aug-26	3,067,786	477,783	572,039
Sep-26	3,067,786	477,783	569,957
Oct-26	3,067,786	477,783	567,874
Nov-26	3,067,786	477,783	565,792
Dec-26	3,067,786	477,783	563,710
12-mo ending	**36,813,438**	**5,733,393**	**6,901,943**

Depreciation Rate *4.208%*

PacifiCorp
Oregon General Rate Case - December 2027
Capital Structure, Property Tax, and Rev Reqt Gross-up
Effective January 1, 2025

Line no.	Capital Structure	Capital Structure	Capital Cost	Weighted Cost	Tax Gross-up	Pre-Tax Cost
1	Debt	49.990%	5.301%	2.650%		2.650%
2	Preferred	0.010%	6.750%	0.001%	1.326	0.001%
3	Common	50.000%	9.500%	4.750%	1.326	6.299%
4			**TOTAL**	**7.401%**		**8.950%**
5	Consolidated Tax Rate		24.587%			
6	Tax Gross-up factor for PTC = (1/(1 - tax rate))		1.3260			

	Property Tax Calculation as filed in Oregon General Rate Case Docket No. UE 433	
7	Total Company	179,679,000
8	Oregon GPS Factor [1]	27.430%
9	Oregon Property Taxes	49,285,137
10	Oregon Gross EPIS	10,309,168,867
11	Oregon Accum. Depr.	(4,028,097,098)
12	Oregon Accum. Amort.	(229,782,174)
13	Oregon Net EPIS	6,051,289,595
14	Estimated Oregon Property Tax Rate	0.814%
15	Oregon General Rate Case Docket No. UE 433 SG Factor [1]	26.884%
16	Oregon General Rate Case Docket No. UE 433 GPS Factor [1]	27.430%

	Franchise Tax and Bad Debt Percentage [2]	**Percentage of Revenue**	**w/ Tax Gross-up**
17	Franchise Tax	2.276%	2.357%
18	Bad Debt Percentage	0.575%	0.595%
19	Resource Suppliers Tax	0.115%	0.119%
20	PUC Fee	0.450%	0.466%

Footnotes:

1 SG Factor & GPS Factor from Oregon General Rate Case Docket No. UE 433
2 Oregon General Rate Case Docket No. UE 433

PacifiCorp
Oregon General Rate Case - December 2027
Docket UM 2426 - Deferral of Residential Rate Change Revenues from RAC Docket UE-451

	Sch. 202 Res. Rate (¢/kWh)	Energy MWh[1]	Revenue Deferral	Amort.	Interest[2,3]	Cumulative Balance
Jan-26	0.269	656,977	1,767,267		5,450	1,772,717
Feb-26	0.269	526,213	1,415,513		15,298	3,203,528
Mar-26	0.269	517,525	1,392,142		24,050	4,619,720
Apr-26			-		28,491	4,648,211
May-26			-		28,666	4,676,877
Jun-26			-		28,843	4,705,720
Jul-26			-		29,021	4,734,742
Aug-26			-		29,200	4,763,942
Sep-26			-		29,380	4,793,322
Oct-26			-		29,561	4,822,883
Nov-26			-		29,744	4,852,627
Dec-26			-		29,927	4,882,554
Jan-27			-		30,112	4,912,666
Feb-27			-		30,297	4,942,963
Mar-27			-		30,484	4,973,447
Apr-27			-		30,672	5,004,120
May-27			-		30,861	5,034,981
Jun-27			-		31,052	5,066,033
Jul-27			-	(75,474)	19,317	5,009,876
Aug-27			-	(150,948)	18,956	4,877,885
Sep-27			-	(150,948)	18,449	4,745,387
Oct-27			-	(150,948)	17,940	4,612,379
Nov-27			-	(150,948)	17,429	4,478,861
Dec-27			-	(150,948)	16,916	4,344,830
Jan-28			-	(150,948)	16,401	4,210,284
Feb-28			-	(150,948)	15,885	4,075,221
Mar-28			-	(150,948)	15,366	3,939,639
Apr-28			-	(150,948)	14,845	3,803,537
May-28			-	(150,948)	14,322	3,666,911
Jun-28			-	(150,948)	13,797	3,529,761
			Annual Amortization	**(1,811,370)**		

1. Reported actual residential loads for January and February 2026, and forecasted residential loads for March 2026.
2. Interest rate through deferal period (WACC - UE-433): 7.40%
3. Interest rate through amortization period (2026 MBTR): 4.61%

PacifiCorp
Oregon General Rate Case - December 2027
UM 2433 - Liabiility Insurance Premium Deferral
Proposed Amortization Schedule

UE-433 Authorized liability insurance premiums in rates (Total Company):	167,101,409
Approved System Overhead Factor:	27.430%
Oregon-allocated authorized liability insurance premiums:	45,835,161
Deferral Application Date:	2/13/2026
Liability Insurance Renewal Date:	2/15/2026
WF 3rd Party Property Liability Renewal Date:	3/1/2026

	In-rates	Actual	Deferral[1]	Amort.	Interest	Ending Balance	Interest Rate[2,3]
Feb-26	1,909,798	1,271,513	(574,457)		(1,771)	(576,228)	7.40%
Mar-26	3,819,597	4,073,555	228,562		(2,849)	(350,515)	7.40%
Apr-26	3,819,597	4,073,555	228,562		(1,457)	(123,410)	7.40%
May-26	3,819,597	4,073,555	228,562		(56)	105,096	7.40%
Jun-26	3,942,693	4,073,555	117,776		1,011	223,883	7.40%
Jul-26	3,961,631	4,073,555	100,732		1,691	326,306	7.40%
Aug-26	3,961,631	4,073,555	100,732		2,323	429,361	7.40%
Sep-26	3,961,631	4,073,555	100,732		2,959	533,051	7.40%
Oct-26	3,961,631	4,073,555	100,732		3,598	637,381	7.40%
Nov-26	3,961,631	4,073,555	100,732		4,242	742,354	7.40%
Dec-26	3,961,631	4,073,555	100,732		4,889	847,975	7.40%
Jan-27	3,961,631	4,073,555	100,732		5,541	954,247	7.40%
Feb-27	3,961,631	4,073,555	100,732		6,196	1,061,174	7.40%
Mar-27	3,961,631	4,073,555	100,732		6,855	1,168,761	7.40%
Apr-27	3,961,631	4,073,555	100,732		7,519	1,277,012	7.40%
May-27	3,961,631	4,073,555	100,732		8,187	1,385,930	7.40%
Jun-27	3,961,631	4,073,555	100,732		8,858	1,495,520	7.40%
Jul-27	3,961,631	4,073,555	50,366	(66,027)	5,715	1,485,573	4.61%
Aug-27				(132,055)	5,453	1,358,972	4.61%
Sep-27				(132,055)	4,967	1,231,885	4.61%
Oct-27				(132,055)	4,479	1,104,309	4.61%
Nov-27				(132,055)	3,989	976,243	4.61%
Dec-27				(132,055)	3,497	847,686	4.61%
Jan-28				(132,055)	3,003	718,634	4.61%
Feb-28				(132,055)	2,507	589,087	4.61%
Mar-28				(132,055)	2,009	459,041	4.61%
Apr-28				(132,055)	1,510	328,497	4.61%
May-28				(132,055)	1,008	197,451	4.61%
Jun-28				(132,055)	505	65,901	4.61%
Jul-28				(66,027)	126	(0)	4.61%
				(1,584,654)			

1. Deferral is 90% of differential between actual and in-rates amounts
2. Interest rate is approved WACC from UE-433 effective 1/1/2025 during amortization period.
3. Interest rate through amortization period is MBTR. Currently using 2026 MBTR as placeholder.

PacifiCorp
Oregon General Rate Case - December 2027
2026 Insurance Policy Renewal - Premiums Summary

	Allocation	Premium Renewal	Oregon Allocated	Effective Date
Excess Liability Insurance Premium (WF & Non-WF) - System	SO	23,311,066	6,364,156	
Excess Liability Insurance Premium (WF) - Divisional	OR[1]	24,152,159	24,152,159	
			30,516,316	2/15/2026
Third-party Property Insurance Preiumms (WF) - Divisional	OR[1]	18,366,342	**18,366,342**	3/1/2026
Total Excess Liability Insurance Premiums - 2026-2027			48,882,658	
Incremental to amounts Approved in UE-433			3,047,497	
Incremental Amount Included in Interim Rates Proposal[2]			**1,704,410**	

Jurisdictional Allocation (PAC)			Divisional Excess Liability Ins. Premium	Oregon Allocated Premium
CA	6.71%			
OR	**73.47%**	Wildfire	32,875,570	24,152,159
WA	19.83%			
UT	0.00%			
ID	0.00%	Wildfire - 3rd Party Property	25,000,000	18,366,342
WY	0.00%			
FERC	0.00%			
Total	**100.00%**			

Notes:
1) The situs excess liability premium is determined by applying the ratio of actual SO allocation attributable to the states covered under the policy.
2) Pro-ration based on requested amount in interim rates proposal relative to total calculated costs eligible for interim rates recovery.

PacifiCorp
Oregon General Rate Case - December 2027
Goodwill Value from Sale of Washington Service Area
Amortization Schedule

		Amortization	Interest[1]	Cumulative Balance[2]
	Opening Balance			40,044,813
2027	July	(596,588)	152,693	39,600,918
	August	(1,193,175)	149,842	38,557,585
	September	(1,193,175)	145,833	37,510,243
	October	(1,193,175)	141,810	36,458,878
	November	(1,193,175)	137,771	35,403,473
	December	(1,193,175)	133,716	34,344,014
2028	January	(1,193,175)	129,646	33,280,486
	February	(1,193,175)	125,561	32,212,871
	March	(1,193,175)	121,459	31,141,155
	April	(1,193,175)	117,342	30,065,322
	May	(1,193,175)	113,209	28,985,355
	June	(1,193,175)	109,060	27,901,240
	July	(1,193,175)	104,895	26,812,961
	August	(1,193,175)	100,715	25,720,500
	September	(1,193,175)	96,518	24,623,842
	October	(1,193,175)	92,305	23,522,972
	November	(1,193,175)	88,076	22,417,872
	December	(1,193,175)	83,830	21,308,527
2029	January	(1,193,175)	79,568	20,194,920
	February	(1,193,175)	75,290	19,077,035
	March	(1,193,175)	70,996	17,954,855
	April	(1,193,175)	66,685	16,828,365
	May	(1,193,175)	62,357	15,697,547
	June	(1,193,175)	58,013	14,562,384
	July	(1,193,175)	53,652	13,422,861
	August	(1,193,175)	49,274	12,278,960
	September	(1,193,175)	44,880	11,130,664
	October	(1,193,175)	40,468	9,977,958
	November	(1,193,175)	36,040	8,820,822
	December	(1,193,175)	31,595	7,659,242
2030	January	(1,193,175)	27,132	6,493,199
	February	(1,193,175)	22,653	5,322,677
	March	(1,193,175)	18,156	4,147,657
	April	(1,193,175)	13,642	2,968,124
	May	(1,193,175)	9,111	1,784,059
	June	(1,193,175)	4,562	595,446
	July	(596,588)	1,142	(0)
Annual Amortization		**(14,318,103)**		

1. Interest rate through amortization period (2026 MBTR): 4.61%
2. Goodwill value of approximately $40.0 million to amortize back to Oregon customers per Docket UP 441, Exhibit PAC/301, Kobliha/2

Docket No. UE 470
Exhibit PAC/810
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Wildfire Mitigation Plan Automatic Adjustment Clause True-Up Illustration

May 2026

PacifiCorp
Oregon General Rate Case - December 2027
2025 Wildfire Mitigation Plan
Automatic Adjustment Clause - UPDATED

	2025 WMP AAC_True-Up		*Eff. 10/31/2025* ***Approved***		
	For Rates Effective Jul-27		ADV 1745	Incl. Indirect Load.	Rate of Return
	Total Company	Oregon Allocated	Oregon Allocated	Oregon Allocated	Oregon Allocated
Capital In-Service	223,613,364	170,590,360	160,894,497	170,590,360	170,590,360
Annual Revenue Requirement	**29,831,434**	**20,496,776**	**19,083,997**	**20,194,089**	**20,496,776**
2024 Outstanding Deferral Amortization		**(38,277,576)**	**(38,277,576)**	**(38,277,576)**	**(38,277,576)**
Forecasted 2025 WMP O&M		**38,030,000**	**38,030,000**	**38,030,000**	**38,030,000**
Total 2025 WMP AAC		**20,249,200**	**18,836,422**	**19,946,513**	**20,249,200**
		-			
Total 2024 WMP AAC (With UE-433 True-Up)		47,821,456	47,821,456	47,821,456	47,821,456
2025 WMP AAC Rate Change		(27,572,257)	(28,985,035)	(27,874,943)	(27,572,257)
			Variance	1,110,091	302,687
				Total True-Up	**1,412,778**

PacifiCorp
Oregon General Rate Case - December 2027
2025 WMP Automatic Adjustment Clause
Revenue Requirement for Recovery_True-Up

2025 WMP Automatic Adjustment Clause

	For Rates Effective Jul-2027			
	Total Company	**Factor**	**Factor %**	**Oregon Allocated**
Capital Investment				
Distribution	146,231,316	OR	100.000%	146,231,316
Transmission	2,869,204	SG	26.158%	750,517
Intangibles	22,891,831	SO	27.301%	6,249,701
General - Situs	4,500,672	OR	100.000%	4,500,672
General - SO	46,580,183	SO	27.301%	12,716,861
General - SG	540,158	SG	26.158%	141,293
Depreciation Reserve				
Distribution	(4,887,399)	OR	100.000%	(4,887,399)
Transmission	(204,845)	SG	26.158%	(53,583)
Intangibles	(12,463,023)	SO	27.301%	(3,402,531)
General - Situs	(357,562)	OR	100.000%	(357,562)
General - SO	(2,764,283)	SO	27.301%	(754,677)
General - SG	(77,542)	SG	26.158%	(20,283)
Accumulated DIT Balance				
Distribution	(2,858,524)	OR	100.000%	(2,858,524)
Transmission	(183,928)	SG	26.158%	(48,111)
Intangibles	(1,454,337)	SO	27.301%	(397,049)
General - Situs	(500,892)	OR	100.000%	(500,892)
General - SO	(2,678,411)	SO	27.301%	(731,233)
General - SG	(88,224)	SG	26.158%	(23,077)
Working Capital	-			-
Net Rate Base	195,094,394			156,555,438
	9.14%			9.14%
Pre-Tax Return on Rate Base	17,824,249			14,303,246
Depreciation				
Distribution	3,327,884	OR	100.000%	3,327,884
Transmission	49,489	SG	26.158%	12,945
Intangibles	4,578,366	SO	27.301%	1,249,940
General - Situs	103,106	OR	100.000%	103,106
General - SO	2,910,601	SO	27.301%	794,623
General - SG	18,767	SG	26.158%	4,909
Property Taxes				
Rev. Reqt. Before Franchise Tax & Bad Debt	28,812,463			19,796,654
Franchise Taxes (2.303%)	678,995			466,528
Bad Debt Expense (0.505%)	171,469			117,814
Resource Suppliers Tax (0.125%)	34,266			23,544
PUC Fee (0.430%)	134,241			92,235
Total Revenue Requirement	**29,831,434**			**20,496,776**
	-			-
Projected Amortization of 2024 Outstanding Deferral Balance				**(38,277,576)**
2025 WMP Forecast O&M				**38,030,000**
2025 WMP AAC Total				**20,249,200**

PacifiCorp
Oregon
2025 Wildfire Mitigation Plan - Automatic Adjustment Clause
2025 Operational & Maintenance Expense Summary

	2025 WMP O&M Forecast			
Program Category	**Distribution**	**Transmission**	**Software**	**Total**
Risk Modeling and Drivers	440,000	-	1,720,000	2,160,000
Inspection & Correction	850,000	370,000	-	1,220,000
Vegetation Management	21,120,000	340,000	-	21,460,000
Grid Hardening	1,810,000	-	-	1,810,000
Situational Awareness	870,000	-	1,490,000	2,360,000
Field Operations & Work Practices	3,040,000	60,000	-	3,100,000
PSPS Program	2,800,000	-	200,000	3,000,000
Public Safety Partner Coordination	170,000	-	-	170,000
Wildfire Safety & Preparedness Engagement Strategy	2,070,000	-	-	2,070,000
Industry Collaboration	70,000	-	-	70,000
Plan Monitoring & Implementation	610,000	-	-	610,000
Total 2024 WMP O&M Forecast	**33,850,000**	**770,000**	**3,410,000**	**38,030,000**

Net 2025 Incremental WMP O&M for AAC **38,030,000**

Source: UM 2207--PacifiCorp's 2024 Wildfire Mitigation Plan https://edocs.puc.state.or.us/efdocs/HAQ/um2207haq325929054.pdf

PacifiCorp
Oregon
2025 Wildfire Mitigation Plan - Automatic Adjustment Clause
2024 Incremental Cost Deferral

	Oregon-Allocated							
	Beg Balance	Veg/Non-Veg O&M Deferral.	Adj for Reimb.	Net Deferral[1]	OR Medical Baseline	Amortization[2]	Interest[3]	End Balance
Dec-23								32,009,380
Jan-24	32,009,380	-	-	-	-	(1,927,357)	139,706	30,221,729
Feb-24	30,221,729	-	-	-	-	(2,679,895)	129,968	27,671,802
Mar-24	27,671,802	-	-	-	-	(3,871,547)	115,812	23,916,066
Apr-24	23,916,066	-	-	-	-	(3,707,782)	99,280	20,307,565
May-24	20,307,565	-	-	-	-	(3,339,436)	83,870	17,051,999
Jun-24	17,051,999	-	-	-	-	(3,082,591)	69,798	14,039,207
Jul-24	14,039,207	-	-	-	-	(3,177,723)	56,027	10,917,511
Aug-24	10,917,511	-	-	-	-	(3,598,379)	41,032	7,360,164
Sep-24	7,360,164	918,918	-	918,918	162,895	(4,055,164)	26,431	4,413,243
Oct-24	4,413,243	2,049,020	-	2,049,020	60,883	(3,391,774)	16,975	3,148,348
Nov-24	3,148,348	1,165,890	-	1,165,890	42,212	(2,900,200)	10,360	1,466,609
Dec-24	1,466,609	1,265,837	(506,999)	758,837	92,730	(3,383,145)	903.69	(1,064,065)
Jan-25	(1,064,065)		52,245			(2,829,873)	(10,547)	(3,852,240)
Feb-25	(3,852,240)		-			(2,839,046)	(22,669)	(6,713,955)
Mar-25	(6,713,955)		(3,079,134)			(4,060,483)	(44,220)	(13,897,792)
Apr-25	(13,897,792)					(3,219,974)	(66,683)	(17,184,449)
May-25	(17,184,449)					(3,237,344)	(80,853)	(20,502,646)
Jun-25	(20,502,646)					(3,237,344)	(95,122)	(23,835,111)
Jul-25	(23,835,111)					(3,237,344)	(109,451)	(27,181,906)
Aug-25	(27,181,906)					(3,237,344)	(123,842)	(30,543,093)
Sep-25	(30,543,093)					(3,237,344)	(138,296)	(33,918,732)
Oct-25	(33,918,732)					(3,237,344)	(152,811)	(37,308,887)
Nov-25	(37,308,887)					3,189,798	(153,570)	(34,272,659)
Dec-25	(34,272,659)					3,189,798	(140,514)	(31,223,375)
Jan-26	(31,223,375)					3,189,798	(127,402)	(28,160,980)
Feb-26	(28,160,980)					3,189,798	(114,234)	(25,085,416)
Mar-26	(25,085,416)					3,189,798	(101,009)	(21,996,627)
Apr-26	(21,996,627)					3,189,798	(87,727)	(18,894,556)
May-26	(18,894,556)					3,189,798	(74,389)	(15,779,147)
Jun-26	(15,779,147)					3,189,798	(60,992)	(12,650,341)
Jul-26	(12,650,341)					3,189,798	(47,538)	(9,508,082)
Aug-26	(9,508,082)					3,189,798	(34,027)	(6,352,310)
Sep-26	(6,352,310)					3,189,798	(20,457)	(3,182,969)
Oct-26	(3,182,969)					3,189,798	(6,829)	0
	12 months Ending Oct-26					**38,277,576**	**(968,689)**	

Notes:

1 Dec-23 End Balance as approved in 2024 WMP AAC (ADV 1631). 2024 Monthly Deferral details can be found on "2024 Actual O&M" tab.

2 Reflect actual amortization through Apr-25, and projected amortization for months thereafter.

3 Interest Rate:

2024 MBTR	5.400%
2025 MBTR	5.160%

PacifiCorp
Oregon
2025 Wildfire Mitigation Plan - Automatic Adjustment Clause
2024 WMP O&M - Monthly Summary

	Total Company												
	Jan-24	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**CY2024**
Veg & Non-Vegetation Management													
Distribution	1,769,296	2,780,761	1,971,136	2,709,588	3,093,986	1,947,449	1,750,314	2,817,157	1,359,441	1,921,517	1,161,512	746,241	24,028,397
Distribution - Meals[1]	317	103	450	413	540	518	846	367	1,089	991	13	203	5,850
Transmission	64,242	37,374	29,784	96,534	148,428	166,513	531,640	324,302	32,996	483,649	16,688	47,380	1,979,530
Transmission - Meals[1]								74					74
													26,013,853

	Oregon Allocated												
	Jan-24	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**CY2024**
Veg & Non-Vegetation Management													
Distribution	1,769,613	2,780,864	1,971,586	2,710,001	3,094,526	1,947,966	1,751,159	2,817,525	1,360,531	1,922,509	1,161,525	746,444	24,034,248
Transmission[2]	16,804	9,776	7,791	25,251	38,825	43,556	139,065	84,849	8,631	126,511	4,365	12,393	517,819
													24,552,067

Deferral Details:

	Jan-24	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**CY2024**
Total Cum. Actual (OR)	1,786,417	4,577,058	6,556,434	9,291,686	12,425,037	14,416,560	16,306,784	19,209,158	20,578,319	22,627,339	23,793,229	24,552,067	24,552,067
Deferral Amount[3]	-	-	-	-	-	-	-	-	918,918	2,049,020	1,165,890	758,837	4,892,665

1 75/25 Split for meals in WMP AAC filings per Settlement in ADV 1529, calculated as 25% reduction to O&M recorded to meals G/L 503115, 503120, and 503430.

2 2024 Allocation Factors

System Generation	26.1577%
System Overhead	27.3010%

3 O&M amount above base rates 19,659,402 per UE-399.

PacifiCorp
Oregon General Rate Case - December 2027
2025 Wildfire Mitigation Plan - Automatic Adjustment Clause
Annual Revenue Requirement of Incremental Capital Investments_True-Up

	2025 WMP AAC Incremental Capital - Total Company For Rates Effective Jul 2027			2025 WMP AAC Incremental Capital - Total Company For Rates Effective Jul 2027		
	Total Company	Price Change	Results with Price Change	Oregon Allocated	Price Change	Results with Price Change
Operating Revenues:						
General Business Revenues	-	29,831,433	29,831,433	-	20,496,776	20,496,776
Interdepartmental	-	-	-	-	-	-
Special Sales	-	-	-	-	-	-
Other Operating Revenues	-	-	-	-	-	-
Total Operating Revenues	-	29,831,433	29,831,433	-	20,496,776	20,496,776
Operating Expenses:						
Customer Accounting	-	171,469	171,469	-	117,814	117,814
Total O&M Expenses	-	171,469	171,469	-	117,814	117,814
Depreciation						
Distribution	3,327,884	-	3,327,884	3,327,884	-	3,327,884
Transmission	49,489	-	49,489	12,945	-	12,945
Intangibles	4,578,366	-	4,578,366	1,249,940	-	1,249,940
General - Situs	103,106	-	103,106	103,106	-	103,106
General - SO	2,910,601		2,910,601	794,623		794,623
General - SG	18,767		18,767	4,909		4,909
Amortization	-	-	-	-	-	-
Taxes Other Than Income	-	847,502	847,502	-	582,307	582,307
Income Taxes - Federal	(5,651,664)	5,775,919	124,255	(3,409,957)	3,968,556	558,599
Income Taxes - State	(1,279,946)	1,308,086	28,140	(772,261)	898,768	126,507
Income Taxes - Def Net						
Distribution	1,130,302	-	1,130,302	1,130,302	-	1,130,302
Transmission	28,847	-	28,847	7,546	-	7,546
Intangibles	305,456	-	305,456	83,392	-	83,392
General - Situs	231,758	-	231,758	231,758	-	231,758
General - SO	1,227,965		1,227,965	335,247		335,247
General - SG	8,144		8,144	2,130		2,130
Investment Tax Credit Adj.	-	-	-	-	-	-
Misc Revenue & Expense	-	-	-	-	-	-
Total Operating Expenses:	6,989,076	8,102,976	15,092,052	3,101,567	5,567,445	8,669,012
Operating Rev For Return:	(6,989,076)	21,728,458	14,739,381	(3,101,567)	14,929,330	11,827,764
Rate Base:						
Electric Plant In Service		-	-			
Distribution	146,231,316	-	146,231,316	146,231,316	-	146,231,316
Transmission	2,869,204	-	2,869,204	750,517	-	750,517
Intangibles	22,891,831	-	22,891,831	6,249,701	-	6,249,701
General - Situs	4,500,672	-	4,500,672	4,500,672	-	4,500,672
General - SO	46,580,183		46,580,183	12,716,861		12,716,861
General - SG	540,158		540,158	141,293		141,293
Total Electric Plant:	223,613,364	-	223,613,364	170,590,360	-	170,590,360
Rate Base Deductions:						
Accum Prov For Deprec						
Distribution	(4,887,399)	-	(4,887,399)	(4,887,399)	-	(4,887,399)
Transmission	(204,845)	-	(204,845)	(53,583)	-	(53,583)
Intangibles	(12,463,023)	-	(12,463,023)	(3,402,531)	-	(3,402,531)
General - Situs	(357,562)	-	(357,562)	(357,562)	-	(357,562)
General - SO	(2,764,283)		(2,764,283)	(754,677)		(754,677)
General - SG	(77,542)		(77,542)	(20,283)		(20,283)
Accum Prov For Amort	-	-	-	-	-	-
Accum Def Income Tax		-	-	-	-	-
Distribution	(2,858,524)	-	(2,858,524)	(2,858,524)	-	(2,858,524)
Transmission	(183,928)	-	(183,928)	(48,111)	-	(48,111)
Intangibles	(1,454,337)	-	(1,454,337)	(397,049)	-	(397,049)
General - Situs	(500,892)	-	(500,892)	(500,892)	-	(500,892)
General - SO	(2,678,411)		(2,678,411)	(731,233)		(731,233)
General - SG	(88,224)		(88,224)	(23,077)		(23,077)
Total Rate Base Deductions	(28,518,971)	-	(28,518,971)	(14,034,923)	-	(14,034,923)
Total Rate Base:	195,094,394	-	195,094,394	156,555,438	-	156,555,438
Return on Rate Base	-3.58%		7.55%	-1.98%		7.56%
Return on Equity	-12.57%		9.70%	-9.37%		9.70%
TAX CALCULATION:						
Operating Revenue	(10,988,214)	28,812,462	17,824,248	(5,493,409)	19,796,655	14,303,246
Other Deductions	-	-	-	-	-	-
Interest (AFUDC)	-	-	-	-	-	-
Interest	5,277,303	-	5,277,303	4,234,825	-	4,234,825
Schedule "M" Additions		-	-		-	-
Distribution	3,327,884	-	3,327,884	3,327,884	-	3,327,884
Transmission	49,489	-	49,489	12,945	-	12,945
Intangibles	4,578,366	-	4,578,366	1,249,940	-	1,249,940
General - Situs	103,106	-	103,106	103,106	-	103,106
General - SO	2,910,601			794,623		794,623
General - SG	18,767			4,909		4,909
Schedule "M" Deductions		-	-		-	-
Distribution	7,925,110	-	7,925,110	7,925,110	-	7,925,110
Transmission	166,820	-	166,820	43,636	-	43,636
Intangibles	5,820,730	-	5,820,730	1,589,118	-	1,589,118
General - Situs	1,045,730	-	1,045,730	1,045,730	-	1,045,730
General - SO	7,905,050			2,158,159		2,158,159
General - SG	51,890			13,573		13,573
Income Before Tax	(28,192,633)	28,812,462	5,647,401	(17,010,151)	19,796,655	2,786,504
State Income Taxes	(1,279,946)	1,308,086	256,392	(772,261)	898,768	126,507
Taxable Income	(26,912,688)	27,504,377	5,391,009	(16,237,890)	18,897,886	2,659,997
Federal Taxes Before Credits	(5,651,664)	5,775,919	1,132,112	(3,409,957)	3,968,556	558,599
Renewable Energy Tax Credit	-	-	-	-	-	-
Federal Income Taxes	(5,651,664)	5,775,919	1,132,112	(3,409,957)	3,968,556	558,599

PacifiCorp
Oregon General Rate Case - December 2027
2025 Wildfire Mitigation Plan - Automatic Adjustment Clause
Total In-Service Capital Summary_True-Up for Indirect Loadings

Cumulative Project In-Service

	Distribution	Transmission	Intangibles	Situs	General SO	SG
2025 GRC Approved for Recovery	58,957,032	2,684,215	16,745,045	1,756,820	10,478,906	540,158
Total Life-time in-service WMP Capital:	**Distribution**	**Transmission**	**Intangibles**	**Situs**	**General SO**	**SG**
Mar-25	146,231,316	2,869,204	22,891,831	4,500,672	46,580,183	540,158
Apr-25	146,231,316	2,869,204	22,891,831	4,500,672	46,580,183	540,158
May-25	146,231,316	2,869,204	22,891,831	4,500,672	46,580,183	540,158
Jun-25	146,231,316	2,869,204	22,891,831	4,500,672	46,580,183	540,158
Jul-25	146,231,316	2,869,204	22,891,831	4,500,672	46,580,183	540,158
Aug-25	146,231,316	2,869,204	22,891,831	4,500,672	46,580,183	540,158
Sep-25	146,231,316	2,869,204	22,891,831	4,500,672	46,580,183	540,158
Oct-25	**146,231,316**	**2,869,204**	**22,891,831**	**4,500,672**	**46,580,183**	**540,158**

Accumulated Reserves

	Distribution	Transmission	Intangibles	Situs	General SO	SG
2025 GRC Approved for Recovery	(1,522,238)	(154,424)	(3,289,578)	(137,584)	(613,291)	(54,166)
	Distribution	**Transmission**	**Intangibles**	**Situs**	**General SO**	**SG**
Mar-25	(2,946,133)	(175,976)	(9,792,309)	(297,417)	(1,066,433)	(66,594)
Apr-25	(3,223,457)	(180,101)	(10,173,840)	(306,009)	(1,308,983)	(68,158)
May-25	(3,500,781)	(184,225)	(10,555,370)	(314,601)	(1,551,533)	(69,722)
Jun-25	(3,778,105)	(188,349)	(10,936,901)	(323,194)	(1,794,083)	(71,286)
Jul-25	(4,055,428)	(192,473)	(11,318,431)	(331,786)	(2,036,633)	(72,850)
Aug-25	(4,332,752)	(196,597)	(11,699,962)	(340,378)	(2,279,183)	(74,414)
Sep-25	(4,610,076)	(200,721)	(12,081,492)	(348,970)	(2,521,733)	(75,978)
Oct-25	**(4,887,399)**	**(204,845)**	**(12,463,023)**	**(357,562)**	**(2,764,283)**	**(77,542)**

Depreciation Expense

	Distribution	Transmission	Intangibles	Situs	General SO	SG
2025 GRC Approved for Recovery	1,339,127	46,268	1,030,742	45,272	592,719	18,568
Projected Annual Depreciation	**3,327,884**	**49,489**	**4,578,366**	**103,106**	**2,910,601**	**18,767**

Depreciation Rate	Distribution	Transmission	Intangibles	Situs	General SO	SG
UE-399 Composite Rates	2.271%	1.724%	6.156%	2.577%	5.656%	3.438%
UE-433 Composite Rates[1]	2.276%	1.725%	20.000%	2.291%	6.249%	3.474%

Note 1 - Intangible rate reflects actual rate for intangible assets.

PacifiCorp
Oregon
2025 Wildfire Mitigation Plan - Automatic Adjustment Clause
Revenue Requirement Variables

Approved Capital Cost and Structure from Oregon 2027 General Rate Case
See Exhibit PAC/802

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	50.00%	5.41%	2.705%		2.705%
Preferred	0.00%	6.75%	0.000%	132.60%	0.000%
Common	50.00%	9.70%	4.850%	132.60%	6.431%
Total	100.00%		7.555%		9.136%

Merged Effective Tax Rate	24.587%
Pre-Tax Bump-up Factor	132.60%

Other Gross Up Items
Approved in Order No. 24-447, docket UE-433

Franchise Tax and Bad Debt Percentage

Franchise Tax	2.276%	2.357%
Bad Debt Percentage	0.575%	0.595%
Resource Suppliers Tax	0.115%	0.119%
PUC Fee	0.450%	0.466%

Actual 2020 Protocol Allocation Factors[1]

Actual 2024 System Generation (SG) Factor	26.1577%
Actual 2024 System Overhead (SO) Factor	27.3010%

Note 1 - Actual 2020 Protocol Allocation Factors as reported in 2024 Results of Operations (Docket No. RE-56), Submitted 4/29/2025

Docket No. UE 470
Exhibit PAC/811
Witness: Shelley E. McCoy

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Shelley E. McCoy

Interim Rates Revenue Requirement Calculation

May 2026

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rates Proposal
Revenue Requirement Summary

The table below presents the company's proposed ratemaking adjustments for the purpose of establishing interim rates during the pendency of its 2027 test period general rate case and their impact on net operating income (NOI), rate base, and the Oregon revenue requirement.

	A	B	C	D	E
Line No.	Adj. No.	Adj. Description	NOI	Rate Base	Rev. Req.
1	IR_1	Property Insurance Reserve Accrual	(7,488,557)	-	10,281,255
2	IR_2	Liability Insurance Premiums	(2,702,301)	-	3,710,066
3	IR_3	Willamette River Crossing	(1,944,370)	161,434,975	19,072,174
4	IR_4	Electric Plant In-Service Update	(8,431,835)	317,596,486	43,845,879
5	IR_5	Incremental Non-Capitalized Labor Expenses	(15,690,442)	-	21,541,856
6			**(36,257,505)**	**479,031,460**	**98,451,230**
7					
8		Amounts Not Requested			(43,389,230)
9					
10		**Total Requested Interim Rate Change**			**55,062,000**

Notes:
(1) The revenue requirement column is calculated using the company's approved return on rate base of 7.401% and the NOI conversion factor of 72.837%

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rates Proposal
Summary of Adjustments

	Total Adjustments	IR_1 Property Insurance Reserve Accrual	IR_2 Liability Insurance Premiums	IR_3 Willamette River Crossing
Operating Revenues:				
Total Operating Revenues	-	-	-	-
Operating Expenses:				
Steam Production	1,884,951			
Nuclear Production	-			
Hydro Production	1,717,603			
Other Power Supply	1,880,615			
Wind Production	394,882			
Solar Production	11,539			
Other Renewable Production	115,673			
Transmission	847,955			
Distribution	10,798,325			
Customer Accounting	1,721,325			
Customer Service & Info	(96,513)			
Sales	-			
Administrative & General	15,042,878	9,930,009	3,583,317	
Total O&M Expenses	34,319,233	9,930,009	3,583,317	-
Depreciation	17,897,715			3,973,008
Amortization	-			
Taxes Other Than Income	-			
Income Taxes - Federal	(13,674,951)	(1,990,629)	(718,333)	(2,316,517)
Income Taxes - State	(3,096,998)	(450,822)	(162,683)	(524,627)
Income Taxes - Def Net	812,506			812,506
Investment Tax Credit Adj.	-			
Misc Revenue & Expense	-			
Total Operating Expenses:	36,257,505	7,488,557	2,702,301	1,944,370
	-			
Operating Rev For Return:	(36,257,505)	(7,488,557)	(2,702,301)	(1,944,370)
Rate Base:				
Electric Plant In Service	570,853,459			164,214,341
Total Electric Plant:	570,853,459	-	-	164,214,341
Rate Base Deductions:				
Accum Prov For Deprec	(46,022,182)			(1,760,930)
Accum Prov For Amort	-			
Accum Def Income Tax	(45,799,816)			(1,018,436)
Unamortized ITC	-			
Customer Adv For Const	-			
Customer Service Deposits	-			
Misc Rate Base Deductions	-			
	-			
Total Rate Base Deductions	(91,821,998)	-	-	(2,779,366)
	-			
Total Rate Base:	479,031,460	-	-	161,434,975
Estimated Price Change	98,451,230	10,281,255	3,710,066	19,072,174
TAX CALCULATION:				
Operating Revenue	(52,216,947)	(9,930,009)	(3,583,317)	(3,973,008)
Other Deductions	-			
Interest (AFUDC)	-			
Interest	12,694,190	-	-	4,277,978
Schedule "M" Additions	3,973,008			3,973,008
Schedule "M" Deductions	7,277,681			7,277,681
Income Before Tax	(68,215,810)	(9,930,009)	(3,583,317)	(11,555,659)
State Income Taxes	(3,096,998)	(450,822)	(162,683)	(524,627)
Taxable Income	(65,118,812)	(9,479,187)	(3,420,634)	(11,031,032)
Federal Income Taxes Before Credits	(13,674,951)	(1,990,629)	(718,333)	(2,316,517)
Energy & Other Tax Credits	-			
Federal Income Taxes	(13,674,951)	(1,990,629)	(718,333)	(2,316,517)

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rates Proposal
Summary of Adjustments

	IR_4 Electric Plant In-Service Update	IR_5 Incremental Non-Capitalized Labor Expenses
Operating Revenues:		
Total Operating Revenues	-	-
Operating Expenses:		
Steam Production		1,884,951
Nuclear Production		
Hydro Production		1,717,603
Other Power Supply		1,880,615
Wind Production		394,882
Solar Production		11,539
Other Renewable Production		115,673
Transmission		847,955
Distribution		10,798,325
Customer Accounting		1,721,325
Customer Service & Info		(96,513)
Sales		
Administrative & General		1,529,552
Total O&M Expenses	-	20,805,907
Depreciation	13,924,707	
Amortization		
Taxes Other Than Income		
Income Taxes - Federal	(4,478,594)	(4,170,877)
Income Taxes - State	(1,014,278)	(944,588)
Income Taxes - Def Net		
Investment Tax Credit Adj.		
Misc Revenue & Expense		
Total Operating Expenses:	8,431,835	15,690,442
Operating Rev For Return:	(8,431,835)	(15,690,442)
Rate Base:		
Electric Plant In Service	406,639,118	
Total Electric Plant:	406,639,118	-
Rate Base Deductions:		
Accum Prov For Deprec	(44,261,252)	
Accum Prov For Amort		
Accum Def Income Tax	(44,781,381)	
Unamortized ITC		
Customer Adv For Const		
Customer Service Deposits		
Misc Rate Base Deductions		
Total Rate Base Deductions	(89,042,632)	-
Total Rate Base:	317,596,486	-
Estimated Price Change	43,845,879	21,541,856
TAX CALCULATION:		
Operating Revenue	(13,924,707)	(20,805,907)
Other Deductions		
Interest (AFUDC)		
Interest	8,416,211	-
Schedule "M" Additions		
Schedule "M" Deductions		
Income Before Tax	(22,340,918)	(20,805,907)
State Income Taxes	(1,014,278)	(944,588)
Taxable Income	(21,326,640)	(19,861,319)
Federal Income Taxes Before Credits	(4,478,594)	(4,170,877)
Energy & Other Tax Credits		
Federal Income Taxes	(4,478,594)	(4,170,877)

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Authorized Rate of Return - Docket UE 433

Capital Structure and Cost Approved in Order 24-447
Effective January 1, 2025

	Capital Structure	Embedded Cost	Weighted Cost
DEBT%	49.990%	5.301%	2.650%
PREFERRED %	0.010%	6.750%	0.001%
COMMON %	50.000%	9.500%	4.750%
			7.401%

Federal Income Tax Rate	21.00%
State Income Tax Rate	4.54%
Effective Merged Income Tax Rate	24.587%

Net to Gross Bump-up Factor	
Operating Revenue	100.000%
Operating Deductions	
Uncollectible Accounts	0.575%
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	96.584%
State Taxes @ 4.54%	4.385%
Sub-Total	92.199%
Federal Income Tax @ 21.00%	19.362%
Net Operating Income	72.837%

Pacificorp Page IR_1
Oregon General Rate Case - December 2027
Interim Rate Proposal
Property Insurance Reserve Accrual

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	
Adjustment to Expense:						
Property Insurance - Transmission	924	523,701	OR	100%	523,701	**Ref IR1.1**
Property Insurance - OR Distribution	924	9,608,132	OR	100%	9,608,132	**Ref IR1.1**
Property Insurance - Non-T&D	924	(201,824)	OR	100%	(201,824)	**Ref IR1.1**
	Total:	**9,930,009**			**9,930,009**	

Description of Adjustment

This adjustment calculates the incremental difference between the annual property insurance reserve accrual amounts proposed in the current general rate case, relative to annual accrual amounts approved in the company's 2025 Oregon general rate case, docket UE 433.

Pacificorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Property Insurance Reserve Accrual

	UE-433 Approved	2027 GRC Amounts	Adjustment	
System Transmission Losses	394,707	918,409	**523,701**	**Ref IR_1**
OR Distribution Losses	13,399,509	23,007,641	**9,608,132**	**Ref IR_1**
System Non-T&D Losses	201,824	-	**(201,824)**	**Ref IR_1**
Annual Accural Amount	13,996,040	23,926,049	9,930,009	

Pacificorp PAGE IR_2
Oregon General Rate Case - December 2027
Interim Rate Proposal
Liability Insurance Premiums

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	
Adjustment to Expense:						
Excess Liability Insurance Premium	925	(39,329,301)	OR	Situs	(39,329,301)	Ref IR_2.1
Divisional Liability Premiums - Wildfire	925	24,279,489	OR	Situs	24,279,489	Ref IR_2.1
Divisional 3rd Party Property Premiums - Wildfire	924	18,463,169	OR	Situs	18,463,169	Ref IR_2.1
Non-T&D Property Insurance Premium	924	169,959	OR	Situs	169,959	Ref IR_2.1
	Total:	**3,583,317**			**3,583,317**	

Description of Adjustment

This adjustment quantifies the increase in liability and property insurance policy premiums between Test Period forecast levels reflected in the current general rate case, as compared to approved levels in the the company's most recently concluded general rate case, docket UE 433.

Pacificorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Liability Insurance Premiums

	UE-433 Approved	Factor	FACTOR %	Oregon Allocated
Excess Liability Insurance Premium (net of 10% sharing)	167,101,409	SO	27.430%	45,835,161
Property Insurance Premium	5,521,349	SO	27.430%	1,514,481

	2027 GRC Amounts	Factor	FACTOR %	Oregon Allocated
Excess Liability Insurance Premium	23,311,066	SO	27.909%	6,505,860
Divisional Liability Premiums - Wildfire	24,279,489	OR	100.000%	24,279,489
Divisional 3rd Party Property Premiums - Wildfire	18,463,169	OR	100.000%	18,463,169
Non-T&D Property Insurance Premium	6,035,497	SO	27.909%	1,684,440

Adjustments:	Oregon Allocated	
Excess Liability Insurance Premium - Wildfire & Non-Wildfire	**(39,329,301)**	**Ref IR_2**
Divisional Liability Premiums - Wildfire	**24,279,489**	**Ref IR_2**
Divisional 3rd Party Property Premiums - Wildfire	**18,463,169**	**Ref IR_2**
Non-T&D Property Insurance Premium	**169,959**	**Ref IR_2**
Total:	3,583,317	

PacifiCorp PAGE IR_3
Oregon General Rate Case - December 2027
Interim Rate Proposal
Willamette River Crossing

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	Ref.
Adjustment to Rate Base:						
Distribution - Oregon	364	164,214,341	OR	Situs	164,214,341	IR_3.1
Adjustment to Depreciation Reserve:						
Accumulated Depreciaton	108364	(1,760,930)	OR	Situs	(1,760,930)	IR_3.1
Adjustment to Expense:						
Depreciation Expense	403	3,973,008	OR	Situs	3,973,008	IR_3.1
Adjustment to Tax:						
Schedule M Additons	SCHMAT	3,973,008	OR	Situs	3,973,008	
Schedule M Deductions	SCHMDT	7,277,681	OR	Situs	7,277,681	
Deferred Income Tax Expense	41110	(976,828)	OR	Situs	(976,828)	
Deferred Income Tax Expense	41010	1,789,334	OR	Situs	1,789,334	
ADIT Balance	282	(1,018,436)	OR	Situs	(1,018,436)	

Description of Adjustment

This adjustment calculates an annual revenue requirement of the Willamette River Crossing distribution project currently in-service and serving customers to be recovered through interim rates that would provide recovery of costs during the pendency of this general rate case. Capital recovery through interim rates are subject to refund.

PacifiCorp PAGE IR_3.1
Oregon General Rate Case - December 2027
Interim Rate Proposal
Willamette River Crossing Capital Investment

In-Service Date	Feb-26
Depreciation Rate	2.340%

	Gross Plant In Service	Accumulated Depreciation	
Dec-25	-	-	
Jan-26	-	-	
Feb-26	194,071,494	(189,191)	
Mar-26	194,071,494	(567,573)	
Apr-26	194,071,494	(945,954)	
May-26	194,071,494	(1,324,336)	
Jun-26	194,071,494	(1,702,718)	
Jul-26	194,071,494	(2,081,099)	
Aug-26	194,071,494	(2,459,481)	
Sep-26	194,071,494	(2,837,863)	
Oct-26	194,071,494	(3,216,244)	
Nov-26	194,071,494	(3,594,626)	
Dec-26	194,071,494	(3,973,008)	
13-mo average	**164,214,341**	**(1,760,930)**	**Ref IR_3**
	Ref IR3		

	O&M Expenses	Depreciation Expense	
Jan-26	-	-	
Feb-26	-	189,191	
Mar-26	-	378,382	
Apr-26	-	378,382	
May-26	-	378,382	
Jun-26	-	378,382	
Jul-26	-	378,382	
Aug-26	-	378,382	
Sep-26	-	378,382	
Oct-26	-	378,382	
Nov-26	-	378,382	
Dec-26	-	378,382	
12-mo ending	**-**	**3,973,008**	**Ref IR_3**

PacifiCorp PAGE IR_4
Oregon General Rate Case - December 2027
Interim Rate Proposal
Electric Plant In-Service Update

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	Ref.
Adjustment to Electric Plant:						
Intangible Plant	Various	(779,695,816)	Various	Various	(218,554,433)	
Steam Production Plant	Various	(418,185,879)	Various	Various	(53,950,138)	
Hydro Production Plant	Various	(23,115,025)	Various	Various	4,015,704	
Wind Production Plant	Various	3,352,529,403	Various	Various	930,513,802	
Solar Production Plant	Various	1,387,818	Various	Various	786,112	
Other Renewable Plant	Various	157,834,136	Various	Various	43,807,771	
Other Production Plant	Various	(3,541,277,562)	Various	Various	(934,229,168)	
Transmission Plant	Various	537,332,597	Various	Various	246,923,982	
Distribution Plant	Various	1,297,521,440	Various	Various	327,949,271	
General Plant	Various	229,547,339	Various	Various	59,376,215	
		813,878,451			406,639,118	IR_4.2
Adjustment to Accumulated Reserves:						
Distribution Plant Accum. Depr.	Various	(188,117,939)	Various	Various	(60,158,746)	
General Plant Accum. Depr.	Various	(447,371,597)	Various	Various	(127,279,465)	
Hydro Production Plant Accum. Depr.	Various	(16,658,414)	Various	Various	(8,943,755)	
Other Production Plant Accum. Depr.	Various	233,111,241	Various	Various	182,961,483	
Other Renewable Plant Accum. Depr.	Various	(104,443,502)	Various	Various	(28,988,894)	
Steam Production Plant Accum. Depr.	Various	115,387,066	Various	Various	2,914,177	
Transmission Plant Accum. Depr.	Various	(233,175,123)	Various	Various	(85,852,418)	
Wind Production Plant Accum. Depr.	Various	(361,914,943)	Various	Various	(100,451,572)	
Solar Production Plant Accum. Depr.	Various	(177,580)	Various	Various	(31,417)	
Accum. Provision for Amortization	Various	642,883,595	Various	Various	181,569,355	
		(360,477,197)			(44,261,252)	IR_4.3

Description of Adjustment

This adjustment calculates the annual revenue requirement of the incremental net electric plant in-service, placed in-service through calendar year 2025, and associated depreciation and tax impacts incremental to approved levels from the company's 2025 general rate case. These assets are currently in-service and serving customers. This adjustment calculates an associated annual revenue requirement to be included in the company's interim rate change request that would provide recovery of these costs during the pendency of its current general rate case. Capital recovery through interim rates are subject to refund.

PacifiCorp PAGE IR_4.1
Oregon General Rate Case - December 2027
Interim Rate Proposal
Electric Plant In-Service Update

	ACCOUNT	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	Ref.
Adjustment to Depreciation Expense:						
Distribution Plant Depreciation	Various	25,809,191	Various	Various	8,664,735	
General Plant Depreciation	Various	30,850,821	Various	Various	8,071,488	
Hydro Production Plant Depreciation	Various	(1,174,260)	Various	Various	(18,251)	
Other Production Plant Depreciation	Various	(144,788,326)	Various	Various	(38,269,182)	
Other Renewable Plant Depreciation	Various	5,480,375	Various	Various	1,521,109	
Steam Production Plant Depreciation	Various	67,690,821	Various	Various	2,289,815	
Transmission Plant Depreciation	Various	12,771,088	Various	Various	5,136,978	
Wind Production Plant Depreciation	Various	152,115,327	Various	Various	42,220,483	
Solar Production Plant Depreciation	Various	29,246	Various	Various	4,028	
General Plant Amortization	Various	(172,352)	Various	Various	(47,573)	
Hydro Production Plant Amortization	Various	855	Various	Various	2,972	
Intangible Plant Amortization	Various	(55,630,367)	Various	Various	(15,683,783)	
Other Production Plant Amortization	Various	(66,384)	Various	Various	(66,384)	
Solar Production Plant Amortization	Various	98,270	Various	Various	98,270	
		93,014,304			13,924,707	IR_4.4
Adjustment to Tax:						
ADIT - CN	282	6,702	OR	Situs	6,702	
ADIT - OR	282	(22,479,854)	OR	Situs	(22,479,854)	
ADIT - DITBAL	282	95,791	OR	Situs	95,791	
ADIT - SE	282	327,393	OR	Situs	327,393	
ADIT - SG	282	(35,746,674)	OR	Situs	(35,746,674)	
ADIT - SO	282	12,950,155	OR	Situs	12,950,155	
ADIT - SNP	282	65,106	OR	Situs	65,106	
ADIT - SNPD	282	-	OR	Situs	-	
		(44,781,381)			(44,781,381)	IR_4.5
		-				

Description of Adjustment

This adjustment calculates the annual revenue requirement of the incremental net electric plant in-service, placed in-service through calendar year 2025, and associated depreciation and tax impacts incremental to approved levels from the company's 2025 general rate case. These assets are currently in-service and serving customers. This adjustment calculates an associated annual revenue requirement to be included in the company's interim rate change request that would provide recovery of these costs during the pendency of its current general rate case. Capital recovery through interim rates are subject to refund.

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Actual Capital In-Service vs. Capital In-Rates

Gross Plant In-Service

Function	Allocation Factor	Actual Balance - EOP Dec-25 Total Company ($)	Actual Balance - EOP Dec-25 Oregon Allocated ($)	UE-433 Approved Oregon Allocated ($)	Oregon Allocated Adjustment
Intangible Plant	SG	203,304,257	56,428,265	56,862,777	(434,512)
Intangible Plant	ID	4,356,591	-	-	-
Intangible Plant	SG-P	103,455,075	28,714,551	27,790,447	924,103
Intangible Plant	SG-U	10,024,217	2,782,279	2,622,724	159,555
Intangible Plant	UT	7,444,448	-	-	-
Intangible Plant	CA	472,341	-	-	-
Intangible Plant	CN	-	-	70,461,152	(70,461,152)
Intangible Plant	OR	4,601,718	4,601,718	4,606,407	(4,689)
Intangible Plant	SE	-	-	1,241	(1,241)
Intangible Plant	SO	-	-	148,736,498	(148,736,498)
Intangible Plant	WA	2,021,245	-	-	-
Intangible Plant	WYP	5,268,401	-	-	-
Steam Production Plant	SG	6,710,400,384	1,862,510,190	1,916,460,328	(53,950,138)
Hydro Production Plant	SG	227,142,652	63,044,748	59,684,139	3,360,610
Hydro Production Plant	SG-P	765,768,659	212,543,492	209,398,102	3,145,390
Hydro Production Plant	SG-U	181,036,015	50,247,586	52,737,882	(2,490,296)
Wind Production Plant	SG	3,352,529,403	930,513,802	-	930,513,802
Solar Production Plant	OR	770,480	770,480	-	770,480
Solar Production Plant	SG	56,322	15,632	-	15,632
Solar Production Plant	UT	561,017	-	-	-
Other Renewable Plant	SG	157,834,136	43,807,771	-	43,807,771
Other Production Plant	SG	2,125,190,583	589,858,859	1,523,122,667	(933,263,808)
Other Production Plant	OR	-	-	965,360	(965,360)
Transmission Plant	SG	11,758,615,179	3,263,671,217	3,016,747,234	246,923,982
Distribution Plant	CA	687,792,583	-	-	-
Distribution Plant	ID	519,278,916	-	-	-
Distribution Plant	OR	3,019,478,157	3,019,478,157	2,705,367,690	314,110,467
Distribution Plant	UT	4,815,917,511	-	-	-
Distribution Plant	WA	744,008,916	-	-	-
Distribution Plant	WYP	828,024,283	-	-	-
Distribution Plant	WYU	178,905,099	-	-	-
Distribution Plant	CN	13,291,169	4,005,925	-	4,005,925
Distribution Plant	SNPD	38,442,586	9,832,879	-	9,832,879
General Plant	CA	19,711,031	-	-	-
General Plant	CN	240,275,216	72,418,345	4,243,948	68,174,397
General Plant	SG	126,315,794	35,059,674	87,884,166	(52,824,492)
General Plant	ID	50,261,171	-	-	-
General Plant	OR	218,517,235	218,517,235	286,104,415	(67,587,180)
General Plant	SO	838,975,823	234,148,852	122,876,543	111,272,310
General Plant	UT	251,135,951	-	-	-
General Plant	WA	42,908,576	-	-	-
General Plant	WYP	76,537,052	-	-	-
General Plant	WYU	19,130,930	-	-	-
General Plant	SE	47,856,058	12,836,328	12,495,148	341,181
		38,397,617,178	10,715,807,985	10,309,168,867	406,639,118

Ref IR_4

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Actual Capital In-Service vs. Capital In-Rates

Accumulated Depreciation & Amortization Reserves

Function	Allocation Factor	Actual Balance - EOP Dec-25 Total Company ($)	Actual Balance - EOP Dec-25 Oregon Allocated ($)	UE-433 Approved Oregon Allocated ($)	Oregon Allocated Adjustment
Distribution Plant Accum. Depr.	CA	(155,268,137)	-	-	-
Distribution Plant Accum. Depr.	ID	(183,090,220)	-	-	-
Distribution Plant Accum. Depr.	OR	(1,241,376,065)	(1,241,376,065)	(1,192,111,426)	(49,264,639)
Distribution Plant Accum. Depr.	UT	(1,289,710,242)	-	-	-
Distribution Plant Accum. Depr.	WA	(331,732,213)	-	-	-
Distribution Plant Accum. Depr.	WYP	(364,400,733)	-	-	-
Distribution Plant Accum. Depr.	WYU	(76,094,931)	-	-	-
Distribution Plant Accum. Depr.	CN	(10,896,499)	(3,284,177)	-	(3,284,177)
Distribution Plant Accum. Depr.	SNPD	(29,751,753)	(7,609,930)	-	(7,609,930)
Distribution Plant Accum. Depr.	SG	-	-	-	-
General Plant Accum. Depr.	CA	(7,325,727)	-	-	-
General Plant Accum. Depr.	CN	(214,583,342)	(64,674,879)	(1,684,429)	(62,990,450)
General Plant Accum. Depr.	SG	(65,434,217)	(18,161,643)	(42,648,693)	24,487,050
General Plant Accum. Depr.	ID	(20,573,053)	-	-	-
General Plant Accum. Depr.	OR	(72,602,940)	(72,602,940)	(96,741,359)	24,138,419
General Plant Accum. Depr.	SE	(1,630,608)	(437,375)	(503,748)	66,373
General Plant Accum. Depr.	SO	(538,317,219)	(150,238,369)	(37,257,512)	(112,980,857)
General Plant Accum. Depr.	UT	(105,323,502)	-	-	-
General Plant Accum. Depr.	WA	(20,641,181)	-	-	-
General Plant Accum. Depr.	WYP	(25,419,359)	-	-	-
General Plant Accum. Depr.	WYU	(8,235,652)	-	-	-
Hydro Production Plant Accum. Depr.	SG	(182,566,616)	(50,672,413)	(49,761,802)	(910,612)
Hydro Production Plant Accum. Depr.	OTHER	-	-	-	-
Hydro Production Plant Accum. Depr.	SG-P	(235,875,766)	(65,468,674)	(59,903,905)	(5,564,769)
Hydro Production Plant Accum. Depr.	SG-U	(93,973,282)	(26,082,824)	(23,614,451)	(2,468,374)
Other Production Plant Accum. Depr.	OR	-	-	(173,154,068)	173,154,068
Other Production Plant Accum. Depr.	SG	(722,916,201)	(200,649,546)	(210,456,961)	9,807,415
Other Production Plant Accum. Depr.	UT	-	-	-	-
Other Renewable Plant Accum. Depr.	SG	(104,443,502)	(28,988,894)	-	(28,988,894)
Steam Production Plant Accum. Depr.	CA	(2,228,016)	-	-	-
Steam Production Plant Accum. Depr.	SG	(5,343,855,169)	(1,483,217,712)	(1,488,273,341)	5,055,629
Steam Production Plant Accum. Depr.	ID	(9,482,541)	-	-	-
Steam Production Plant Accum. Depr.	OR	(2,141,452)	(2,141,452)	-	(2,141,452)
Steam Production Plant Accum. Depr.	SE	-	-	-	-
Steam Production Plant Accum. Depr.	UT	(85,268,145)	-	-	-
Steam Production Plant Accum. Depr.	WA	(17,848,079)	-	-	-
Steam Production Plant Accum. Depr.	WYP	(25,509,780)	-	-	-
Transmission Plant Accum. Depr.	SG	(2,658,341,004)	(737,837,822)	(651,985,404)	(85,852,418)
Wind Production Plant Accum. Depr.	SG	(361,914,943)	(100,451,572)	-	(100,451,572)
Solar Production Plant Accum. Depr.	OR	(12,750)	(12,750)	-	(12,750)
Solar Production Plant Accum. Depr.	SG	(67,257)	(18,667)	-	(18,667)
Solar Production Plant Accum. Depr.	UT	(97,573)	-	-	-
Accum. Provision for Amortization	CA	(513,171)	-	-	-
Accum. Provision for Amortization	ID	(1,333,771)	-	-	-
Accum. Provision for Amortization	OR	(5,783,025)	(5,783,025)	(5,631,169)	(151,856)
Accum. Provision for Amortization	SO	(1,892,405)	(528,149)	(112,834,823)	112,306,674
Accum. Provision for Amortization	UT	(477,036)	-	-	-
Accum. Provision for Amortization	WA	(2,314,675)	-	-	-
Accum. Provision for Amortization	WYP	(5,177,579)	-	-	-
Accum. Provision for Amortization	SG-P	(57,122,747)	(15,854,747)	(14,517,606)	(1,337,141)
Accum. Provision for Amortization	CN	-	-	(63,528,158)	63,528,158
Accum. Provision for Amortization	SG	(86,755,990)	(24,079,624)	(31,492,368)	7,412,745
Accum. Provision for Amortization	SE	-	-	(770)	770
Accum. Provision for Amortization	SG-U	(7,087,851)	(1,967,274)	(1,777,279)	(189,994)
		(14,777,407,917)	(4,302,140,524)	(4,257,879,272)	(44,261,252)

Ref IR_4

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Actual Capital In-Service vs. Capital In-Rates

Depreciation Expense

Function	Allocation Factor	Actual - 12 ME Dec-25 Total Company ($)	Actual - 12 ME Dec-25 Oregon Allocated ($)	UE-433 Approved Oregon Allocated ($)	Oregon Allocated Adjustment
Distribution Plant Depreciation	CA	17,547,838	-	-	-
Distribution Plant Depreciation	ID	13,002,529	-	-	-
Distribution Plant Depreciation	OR	69,386,769	69,386,769	61,111,801	8,274,968
Distribution Plant Depreciation	UT	115,216,379	-	-	-
Distribution Plant Depreciation	WA	19,049,628	-	-	-
Distribution Plant Depreciation	WYP	22,541,640	-	-	-
Distribution Plant Depreciation	WYU	4,242,303	-	-	-
Distribution Plant Depreciation	OTHER	890,574	-	-	-
Distribution Plant Depreciation	SG	1,463	406	-	406
Distribution Plant Depreciation	CN	93,864	28,290	-	28,290
Distribution Plant Depreciation	SNPD	1,411,637	361,070	-	361,070
General Plant Depreciation	CA	215,508	-	-	-
General Plant Depreciation	CN	9,260,078	2,790,964	217,934	2,573,031
General Plant Depreciation	SG	3,102,790	861,197	3,035,744	(2,174,546)
General Plant Depreciation	ID	615,685	-	-	-
General Plant Depreciation	OR	2,740,956	2,740,956	6,424,180	(3,683,223)
General Plant Depreciation	SE	96,502	25,884	29,716	(3,831)
General Plant Depreciation	SO	68,080,262	19,000,446	7,640,388	11,360,059
General Plant Depreciation	UT	3,746,248	-	-	-
General Plant Depreciation	WA	549,944	-	-	-
General Plant Depreciation	WYP	912,062	-	-	-
General Plant Depreciation	WYU	365,535	-	-	-
Hydro Production Plant Depreciation	SG	3,490,330	968,761	1,420,662	(451,901)
Hydro Production Plant Depreciation	SG-P	22,298,988	6,189,212	5,553,577	635,635
Hydro Production Plant Depreciation	SG-U	8,343,500	2,315,786	2,517,771	(201,984)
Other Production Plant Depreciation	OR	-	-	61,373	(61,373)
Other Production Plant Depreciation	SG	80,455,300	22,330,831	60,538,639	(38,207,808)
Other Production Plant Depreciation	UT	1,074	-	-	-
Other Renewable Plant Depreciation	SG	5,480,375	1,521,109	-	1,521,109
Steam Production Plant Depreciation	SG	308,820,080	85,714,788	83,424,973	2,289,815
Steam Production Plant Depreciation	OTHER	69,183,512	-	-	-
Transmission Plant Depreciation	SG	206,175,677	57,225,244	52,088,266	5,136,978
Transmission Plant Depreciation	OTHER	346,200	-	-	-
Wind Production Plant Depreciation	SG	152,115,327	42,220,483	-	42,220,483
Solar Production Plant Depreciation	OR	3,730	3,730	-	3,730
Solar Production Plant Depreciation	SG	1,074	298	-	298
Solar Production Plant Depreciation	UT	24,442	-	-	-
General Plant Amortization	CA	2,585	-	-	-
General Plant Amortization	ID	-	-	-	-
General Plant Amortization	OR	75,382	75,382	139,579	(64,197)
General Plant Amortization	SO	100,217	27,969	11,346	16,624
General Plant Amortization	UT	-	-	-	-
General Plant Amortization	WA	108,236	-	-	-
General Plant Amortization	WYP	3,464	-	-	-
Hydro Production Plant Amortization	SG-P	314,732	87,356	84,383	2,972
Intangible Plant Amortization	CN	368,468	111,055	4,785,713	(4,674,658)
Intangible Plant Amortization	SG	5,985,019	1,661,176	1,587,264	73,913
Intangible Plant Amortization	ID	-	-	-	-
Intangible Plant Amortization	OR	8,853	8,853	11,216	(2,363)
Intangible Plant Amortization	SE	76	20	248	(228)
Intangible Plant Amortization	SG-P	2,697,714	748,766	720,638	28,128
Intangible Plant Amortization	SG-U	251,815	69,893	84,585	(14,692)
Intangible Plant Amortization	SO	(616,199)	(171,974)	10,921,908	(11,093,882)
Intangible Plant Amortization	UT	94,924	-	-	-
Intangible Plant Amortization	WA	5	-	-	-
Intangible Plant Amortization	WYP	59,527	-	-	-
Other Production Plant Amortization	OR	4,257	4,257	70,641	(66,384)
Solar Production Plant Amortization	OR	98,270	98,270	-	98,270
		1,219,367,146	316,407,251	302,482,544	13,924,707

Ref IR_4.1

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Actual Capital In-Service vs. Capital In-Rates

Accumulated Deferred Income Tax Liability

Allocation Factor	Actual Balance - EOP Dec-25 Total Company ($)	Actual Balance - EOP Dec-25 Oregon Allocated ($)	UE-433 Approved Oregon Allocated ($)	Oregon Allocated Adjustment
CA	(30,699,955)	-	-	-
CN	-	-	(6,702)	6,702
ID	(32,788,016)	-	-	-
OR	(86,805,684)	(86,805,684)	(64,325,830)	(22,479,854)
OTHER	787,741	-	-	-
UT	(302,087,340)	-	-	-
WA	(30,574,186)	-	-	-
WYP	(69,339,155)	-	-	-
WYU		-	-	-
DITBAL		-	(95,791)	95,791
NREG		-	-	-
SE	-	-	(327,393)	327,393
SG	(2,511,402,836)	(697,054,289)	(661,307,615)	(35,746,674)
SO	(92,576,907)	(25,837,189)	(38,787,344)	12,950,155
SNP	-	-	(65,106)	65,106
SNPD	-	-	-	-
	(3,155,486,337)	(809,697,162)	(764,915,781)	(44,781,381)

Ref IR_4.1

PacifiCorp PAGE IR_5
Oregon General Rate Case - December 2027
Interim Rate Proposal
Incremental Non-Capitalized Labor Expenses

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Steam Production	Various	3	1,884,951	OR	Situs	1,884,951	IR_5.1
Hydro Production	Various	3	1,717,603	OR	Situs	1,717,603	IR_5.1
Other Power Supply	Various	3	1,880,615	OR	Situs	1,880,615	IR_5.1
Wind Production	Various	3	394,882	OR	Situs	394,882	IR_5.1
Solar Production	Various	3	11,539	OR	Situs	11,539	IR_5.1
Other Renewable Production	Various	3	115,673	OR	Situs	115,673	IR_5.1
Transmission Expense	Various	3	847,955	OR	Situs	847,955	IR_5.1
Distribution Expense	Various	3	10,798,325	OR	Situs	10,798,325	IR_5.1
Customer Accounting	Various	3	1,721,325	OR	Situs	1,721,325	IR_5.1
Customer Service & Info	Various	3	(96,513)	OR	Situs	(96,513)	IR_5.1
Administrative & General	Various	3	1,529,552	OR	Situs	1,529,552	IR_5.1
			20,805,907			20,805,907	

Description of Adjustment

This adjustment quantifies the incremental non-capitalized labor expenses on an annualized basis between the 12 months ended June 2025, when compared to approved noramlized levels approved in the Company's most recently concluded general rate case, docket UE 433.

PacifiCorp Page IR_5.1
Oregon General Rate Case - December 2027
Interim Rate Proposal
Summary of Non-Capitalized Labor Costs

	$ Oregon-Allocated		
Expense	**UE 433 Approved**	**12 ME June 2025 Annualized**	**Adjustment**
Steam Production	31,790,520	33,675,471	1,884,951
Hydro Production	7,462,606	9,180,209	1,717,603
Other Power Supply	12,650,352	14,530,967	1,880,615
Wind Production	-	394,882	394,882
Solar Production	-	11,539	11,539
Other Renewable Production	-	115,673	115,673
Transmission Expense	12,122,045	12,969,999	847,955
Distribution Expense	61,865,435	72,663,760	10,798,325
Customer Accounting	11,028,599	12,749,925	1,721,325
Customer Service & Info	3,921,330	3,824,818	(96,513)
Administrative & General	8,172,629	9,702,182	1,529,552
Total Non-Capitalized Labor	**149,013,517**	**169,819,424**	**20,805,907**
	Ref IR_5.5	**Ref IR_5.8**	**Ref IR_5.1**

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Wages & Employee Benefits Amounts
Approved in Docket UE 433, Final Order No. 24-447

	Total Co.		Total Company			Oregon Allocated	
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%	683,096	13,820,742	26.884%	183,645	3,715,590
502SG	19,916,064	2.5702%	1,035,542	20,951,606	26.884%	278,397	5,632,663
503SE	115,750	0.0149%	6,018	121,769	26.339%	1,585	32,073
505SG	19,410	0.0025%	1,009	20,419	26.884%	271	5,490
506SG	30,844,099	3.9804%	1,603,748	32,447,847	26.884%	431,154	8,723,330
510SG	3,853,094	0.4972%	200,343	4,053,437	26.884%	53,860	1,089,732
511SG	6,962,821	0.8985%	362,034	7,324,855	26.884%	97,330	1,969,226
512SG	24,031,638	3.1013%	1,249,532	25,281,170	26.884%	335,926	6,796,629
513SG	11,584,965	1.4950%	602,364	12,187,329	26.884%	161,940	3,276,461
514SG	1,942,321	0.2507%	100,992	2,043,312	26.884%	27,151	549,327
535SG-P	5,141,090	0.6635%	267,312	5,408,402	26.884%	71,865	1,454,003
535SG-U	4,649,310	0.6000%	241,742	4,891,052	26.884%	64,990	1,314,918
536SG-P	56,973	0.0074%	2,962	59,936	26.884%	796	16,113
537SG-P	628,768	0.0811%	32,693	661,461	26.884%	8,789	177,828
537SG-U	1,068	0.0001%	56	1,124	26.884%	15	302
539SG-P	7,802,656	1.0069%	405,701	8,208,357	26.884%	109,069	2,206,748
539SG-U	5,083,804	0.6561%	264,334	5,348,138	26.884%	71,064	1,437,802
540SG-P	533	0.0001%	28	561	26.884%	7	151
542SG-P	282,649	0.0365%	14,696	297,346	26.884%	3,951	79,939
542SG-U	11,551	0.0015%	601	12,151	26.884%	161	3,267
543SG-P	480,275	0.0620%	24,972	505,247	26.884%	6,714	135,831
543SG-U	301,121	0.0389%	15,657	316,778	26.884%	4,209	85,163
544SG-P	766,343	0.0989%	39,846	806,190	26.884%	10,712	216,737
544SG-U	258,268	0.0333%	13,429	271,696	26.884%	3,610	73,043
545SG-P	797,587	0.1029%	41,471	839,058	26.884%	11,149	225,574
545SG-U	124,415	0.0161%	6,469	130,884	26.884%	1,739	35,187
546SG	10,131	0.0013%	527	10,658	26.884%	142	2,865
548SG	6,710,709	0.8660%	348,925	7,059,634	26.884%	93,806	1,897,923
549OR	20,826	0.0027%	1,083	21,909	Situs	1,083	21,909
549SG	4,826,809	0.6229%	250,971	5,077,780	26.884%	67,472	1,365,118
552SG	924,783	0.1193%	48,084	972,867	26.884%	12,927	261,547
553SG	1,710,241	0.2207%	88,924	1,799,166	26.884%	23,907	483,690
554SG	90,852	0.0117%	4,724	95,576	26.884%	1,270	25,695
556SG	589,209	0.0760%	30,636	619,845	26.884%	8,236	166,640
557ID	48,318	0.0062%	2,512	50,831	Situs	-	-
557WYU	-	0.0000%	-	-	Situs	-	-
557SG	29,789,128	3.8443%	1,548,895	31,338,023	26.884%	416,407	8,424,963
560SG	10,541,400	1.3604%	548,103	11,089,503	26.884%	147,353	2,981,319
561SG	12,150,429	1.5680%	631,765	12,782,195	26.884%	169,845	3,436,385
562SG	2,881,367	0.3718%	149,818	3,031,185	26.884%	40,277	814,909
563SG	598,310	0.0772%	31,109	629,419	26.884%	8,363	169,214
566SG	98,799	0.0127%	5,137	103,937	26.884%	1,381	27,942
567SG	117,939	0.0152%	6,132	124,071	26.884%	1,649	33,356
568SG	1,504,112	0.1941%	78,207	1,582,318	26.884%	21,025	425,393
569SG	3,264,531	0.4213%	169,740	3,434,271	26.884%	45,633	923,275
570SG	8,332,889	1.0754%	433,271	8,766,160	26.884%	116,481	2,356,708
571SG	3,311,175	0.4273%	172,166	3,483,340	26.884%	46,285	936,467
572SG	60,380	0.0078%	3,139	63,519	26.884%	844	17,077
580CA	877,274	0.1132%	45,614	922,888	Situs	-	-
580ID	114,755	0.0148%	5,967	120,721	Situs	-	-
580OR	1,586,945	0.2048%	82,514	1,669,459	Situs	82,514	1,669,459
580SNPD	8,785,847	1.1338%	456,823	9,242,670	24.998%	114,198	2,310,520
580UT	460,903	0.0595%	23,965	484,867	Situs	-	-
580WA	93,833	0.0121%	4,879	98,712	Situs	-	-
580WYP	106,335	0.0137%	5,529	111,864	Situs	-	-
580WYU	44,059	0.0057%	2,291	46,350	Situs	-	-
581SNPD	16,367,477	2.1122%	851,032	17,218,509	24.998%	212,744	4,304,353
582CA	45,954	0.0059%	2,389	48,343	Situs	-	-
582ID	321,938	0.0415%	16,739	338,678	Situs	-	-
582OR	412,937	0.0533%	21,471	434,408	Situs	21,471	434,408
582SNPD	312	0.0000%	16	328	24.998%	4	82

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Wages & Employee Benefits Amounts
Approved in Docket UE 433, Final Order No. 24-447

	Total Co.		Total Company			Oregon Allocated	
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
582UT	1,183,713	0.1528%	61,548	1,245,261	Situs	-	-
582WA	49,790	0.0064%	2,589	52,379	Situs	-	-
582WYP	549,581	0.0709%	28,576	578,156	Situs	-	-
583CA	660,261	0.0852%	34,330	694,592	Situs	-	-
583ID	528,614	0.0682%	27,485	556,099	Situs	-	-
583OR	4,443,618	0.5734%	231,047	4,674,665	Situs	231,047	4,674,665
583UT	3,808,711	0.4915%	198,035	4,006,746	Situs	-	-
583WA	392,918	0.0507%	20,430	413,347	Situs	-	-
583WYP	666,312	0.0860%	34,645	700,957	Situs	-	-
583WYU	54,856	0.0071%	2,852	57,709	Situs	-	-
585SNPD	258,639	0.0334%	13,448	272,087	24.998%	3,362	68,017
586CA	88,257	0.0114%	4,589	92,846	Situs	-	-
586ID	97,875	0.0126%	5,089	102,964	Situs	-	-
586OR	1,071,052	0.1382%	55,690	1,126,742	Situs	55,690	1,126,742
586UT	469,336	0.0606%	24,403	493,739	Situs	-	-
586WA	177,673	0.0229%	9,238	186,911	Situs	-	-
586WYP	203,859	0.0263%	10,600	214,459	Situs	-	-
586WYU	39,863	0.0051%	2,073	41,936	Situs	-	-
587CA	425,327	0.0549%	22,115	447,442	Situs	-	-
587ID	878,598	0.1134%	45,683	924,281	Situs	-	-
587OR	5,553,756	0.7167%	288,769	5,842,525	Situs	288,769	5,842,525
587UT	6,098,917	0.7871%	317,115	6,416,032	Situs	-	-
587WA	1,234,284	0.1593%	64,177	1,298,461	Situs	-	-
587WYP	1,108,595	0.1431%	57,642	1,166,237	Situs	-	-
587WYU	107,593	0.0139%	5,594	113,187	Situs	-	-
588CA	1,254	0.0002%	65	1,319	Situs	-	-
588ID	139,466	0.0180%	7,252	146,718	Situs	-	-
588OR	42,474	0.0055%	2,208	44,682	Situs	2,208	44,682
588SNPD	17,817,247	2.2993%	926,413	18,743,660	24.998%	231,589	4,685,616
588UT	755,232	0.0975%	39,268	794,500	Situs	-	-
588WA	17,888	0.0023%	930	18,819	Situs	-	-
588WYP	229,377	0.0296%	11,927	241,304	Situs	-	-
588WYU	56,056	0.0072%	2,915	58,971	Situs	-	-
589CA	16,455	0.0021%	856	17,310	Situs	-	-
589ID	21,323	0.0028%	1,109	22,431	Situs	-	-
589OR	57,483	0.0074%	2,989	60,472	Situs	2,989	60,472
589UT	246,347	0.0318%	12,809	259,156	Situs	-	-
589WA	10,116	0.0013%	526	10,642	Situs	-	-
589WYP	78,303	0.0101%	4,071	82,374	Situs	-	-
589WYU	12,399	0.0016%	645	13,044	Situs	-	-
590CA	111,455	0.0144%	5,795	117,250	Situs	-	-
590ID	47,927	0.0062%	2,492	50,419	Situs	-	-
590OR	864,307	0.1115%	44,940	909,246	Situs	44,940	909,246
590SNPD	2,858,194	0.3688%	148,613	3,006,806	24.998%	37,151	751,654
590UT	824,222	0.1064%	42,856	867,078	Situs	-	-
590WA	227,075	0.0293%	11,807	238,881	Situs	-	-
590WYP	222,442	0.0287%	11,566	234,008	Situs	-	-
591SNPD	2,861	0.0004%	149	3,009	24.998%	37	752
592CA	536,453	0.0692%	27,893	564,347	Situs	-	-
592ID	477,956	0.0617%	24,851	502,808	Situs	-	-
592OR	2,412,418	0.3113%	125,434	2,537,852	Situs	125,434	2,537,852
592SNPD	2,576,109	0.3324%	133,946	2,710,054	24.998%	33,484	677,470
592UT	1,683,775	0.2173%	87,548	1,771,323	Situs	-	-
592WA	646,541	0.0834%	33,617	680,158	Situs	-	-
592WYP	808,312	0.1043%	42,028	850,341	Situs	-	-
593CA	4,739,724	0.6117%	246,443	4,986,168	Situs	-	-
593ID	3,988,288	0.5147%	207,372	4,195,660	Situs	-	-
593OR	23,670,162	3.0546%	1,230,737	24,900,900	Situs	1,230,737	24,900,900
593SNPD	2,423,150	0.3127%	125,992	2,549,143	24.998%	31,496	637,245
593UT	23,539,710	3.0378%	1,223,954	24,763,664	Situs	-	-
593WA	5,191,020	0.6699%	269,909	5,460,928	Situs	-	-

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Wages & Employee Benefits Amounts
Approved in Docket UE 433, Final Order No. 24-447

	Total Co.		Total Company			Oregon Allocated	
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
593WYP	6,158,124	0.7947%	320,193	6,478,317	Situs	-	-
593WYU	599,279	0.0773%	31,160	630,439	Situs	-	-
594CA	418,542	0.0540%	21,762	440,305	Situs	-	-
594ID	549,998	0.0710%	28,597	578,596	Situs	-	-
594OR	4,939,341	0.6374%	256,823	5,196,163	Situs	256,823	5,196,163
594SNPD	7,261	0.0009%	378	7,638	24.998%	94	1,909
594UT	9,749,327	1.2581%	506,919	10,256,246	Situs	-	-
594WA	1,203,219	0.1553%	62,562	1,265,781	Situs	-	-
594WYP	596,371	0.0770%	31,009	627,380	Situs	-	-
594WYU	153,984	0.0199%	8,006	161,990	Situs	-	-
595SNPD	799,654	0.1032%	41,578	841,232	24.998%	10,394	210,295
595WYU	4,506	0.0006%	234	4,740	Situs	-	-
596CA	56,276	0.0073%	2,926	59,202	Situs	-	-
596ID	47,599	0.0061%	2,475	50,074	Situs	-	-
596OR	518,153	0.0669%	26,942	545,095	Situs	26,942	545,095
596UT	141,453	0.0183%	7,355	148,807	Situs	-	-
596WA	80,433	0.0104%	4,182	84,615	Situs	-	-
596WYP	236,567	0.0305%	12,300	248,867	Situs	-	-
596WYU	64,903	0.0084%	3,375	68,278	Situs	-	-
597CA	12,087	0.0016%	628	12,716	Situs	-	-
597ID	35,686	0.0046%	1,856	37,542	Situs	-	-
597OR	139,593	0.0180%	7,258	146,851	Situs	7,258	146,851
597SNPD	17,378	0.0022%	904	18,282	24.998%	226	4,570
597UT	213,154	0.0275%	11,083	224,237	Situs	-	-
597WA	13,559	0.0017%	705	14,264	Situs	-	-
597WYP	21,758	0.0028%	1,131	22,889	Situs	-	-
597WYU	8,777	0.0011%	456	9,234	Situs	-	-
598CA	1,932	0.0002%	100	2,033	Situs	-	-
598OR	25,327	0.0033%	1,317	26,644	Situs	1,317	26,644
598SNPD	369,783	0.0477%	19,227	389,010	24.998%	4,806	97,246
598WA	18,479	0.0024%	961	19,440	Situs	-	-
901CN	2,282,891	0.2946%	118,700	2,401,591	30.706%	36,447	737,421
902CA	381,995	0.0493%	19,862	401,857	Situs	-	-
902CN	566,752	0.0731%	29,468	596,220	30.706%	9,048	183,073
902ID	617,716	0.0797%	32,118	649,834	Situs	-	-
902OR	1,365,793	0.1763%	71,015	1,436,808	Situs	71,015	1,436,808
902UT	4,102,727	0.5295%	213,323	4,316,049	Situs	-	-
902WA	841,816	0.1086%	43,770	885,586	Situs	-	-
902WYP	823,081	0.1062%	42,796	865,877	Situs	-	-
902WYU	175,129	0.0226%	9,106	184,235	Situs	-	-
903CA	29,226	0.0038%	1,520	30,746	Situs	-	-
903CN	25,477,665	3.2879%	1,324,719	26,802,384	30.706%	406,762	8,229,814
903ID	113,080	0.0146%	5,880	118,959	Situs	-	-
903OR	419,663	0.0542%	21,821	441,484	Situs	21,821	441,484
903UT	1,063,027	0.1372%	55,272	1,118,300	Situs	-	-
903WA	104,217	0.0134%	5,419	109,636	Situs	-	-
903WYP	179,029	0.0231%	9,309	188,337	Situs	-	-
903WYU	29,210	0.0038%	1,519	30,729	Situs	-	-
908CN	2,941,885	0.3796%	152,964	3,094,849	30.706%	46,968	950,290
908ID	0	0.0000%	0	0	Situs	-	-
908OR	2,216,691	0.2861%	115,257	2,331,948	Situs	115,257	2,331,948
908OTHER	1,410	0.0002%	73	1,484	0.000%	-	-
908UT	2,881,929	0.3719%	149,847	3,031,775	Situs	-	-
908WA	170,516	0.0220%	8,866	179,382	Situs	-	-
908WYP	978,104	0.1262%	50,857	1,028,960	Situs	-	-
909CN	1,978,488	0.2553%	102,872	2,081,360	30.706%	31,587	639,093
920OR	(754,225)	-0.0973%	(39,216)	(793,441)	Situs	(39,216)	(793,441)
920SO	80,268,539	10.3586%	4,173,587	84,442,125	27.425%	1,144,626	23,158,646
921SO	41,013	0.0053%	2,132	43,146	27.425%	585	11,833
922SO	(24,724,390)	-3.1907%	(1,285,552)	(26,009,942)	27.425%	(352,569)	(7,133,348)
928CA	59,356	0.0077%	3,086	62,442	Situs	-	-

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Approved in Docket UE 433, Final Order No. 24-447

	Total Co.		Total Company			Oregon Allocated	
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
928OR	129,439	0.0167%	6,730	136,169	Situs	6,730	136,169
928SO	230,194	0.0297%	11,969	242,163	27.425%	3,283	66,414
928WA	327,189	0.0422%	17,012	344,201	Situs	-	-
928WYP	191,227	0.0247%	9,943	201,170	Situs	-	-
929SO	(27,685,156)	-3.5727%	(1,439,498)	(29,124,654)	27.425%	(394,789)	(7,987,572)
935CA	600	0.0001%	31	631	Situs	-	-
935OR	88,483	0.0114%	4,601	93,083	Situs	4,601	93,083
935SO	2,151,863	0.2777%	111,887	2,263,750	27.425%	30,685	620,844
935UT	24,433	0.0032%	1,270	25,703	Situs	-	-
935WA	158	0.0000%	8	166	Situs	-	-
935WYP	2,184	0.0003%	114	2,297	Situs	-	-
Utility Labor	490,396,090	63.29%	25,498,292	515,894,382		7,365,054	**149,013,517**
							Ref IR_5.1
Capital/Non Utility	284,502,206	36.71%	14,792,777	299,294,984			
Total Labor	774,898,296	100.00%	40,291,069	815,189,365			

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			Total Co.		Total Company			Oregon Allocated	
			Actual 12 Months Ended		Annualization	Annualized 12 Months Ended	Oregon	Annualization Adjustment Oregon	Annualized 12 Months Ended
Indicator	FERC	Factor	June 2025	% Of Total	Adjustment	June 2025	Allocation %	Allocated	June 2025
500SG	500	SG	14,697,888	1.660%	104,177	14,802,065	27.756%	28,915	4,108,398
502SG	502	SG	23,986,017	2.710%	170,010	24,156,027	27.756%	47,187	6,704,644
503SE	503	SE	134,479	0.015%	953	135,432	26.823%	256	36,327
505SG	505	SG	15,301	0.002%	108	15,410	27.756%	30	4,277
506SG	506	SG	30,220,419	3.414%	214,198	30,434,618	27.756%	59,452	8,447,303
510SG	510	SG	3,019,857	0.341%	21,404	3,041,261	27.756%	5,941	844,119
511SG	511	SG	6,547,743	0.740%	46,410	6,594,152	27.756%	12,881	1,830,245
512SG	512	SG	26,212,774	2.961%	185,793	26,398,567	27.756%	51,568	7,327,074
513SG	513	SG	13,003,912	1.469%	92,170	13,096,082	27.756%	25,582	3,634,893
514SG	514	SG	2,640,894	0.298%	18,718	2,659,612	27.756%	5,195	738,191
535SG-P	535	SG-P	4,766,633	0.539%	33,785	4,800,419	27.756%	9,377	1,332,384
535SG-U	535	SG-U	12,260,174	1.385%	86,899	12,347,073	27.756%	24,119	3,427,001
536SG-P	536	SG-P	50,208	0.006%	356	50,564	27.756%	99	14,034
537SG-P	537	SG-P	878,955	0.099%	6,230	885,185	27.756%	1,729	245,688
537SG-U	537	SG-U	32,115	0.004%	228	32,343	27.756%	63	8,977
539SG-P	539	SG-P	5,743,766	0.649%	40,711	5,784,477	27.756%	11,300	1,605,515
539SG-U	539	SG-U	6,454,774	0.729%	45,751	6,500,525	27.756%	12,698	1,804,258
540SG-P	540	SG-P	874	0.000%	6	880	27.756%	2	244
542SG-P	542	SG-P	273,643	0.031%	1,940	275,583	27.756%	538	76,490
542SG-U	542	SG-U	16,759	0.002%	119	16,878	27.756%	33	4,685
543SG-P	543	SG-P	271,477	0.031%	1,924	273,401	27.756%	534	75,884
543SG-U	543	SG-U	195,568	0.022%	1,386	196,954	27.756%	385	54,666
544SG-P	544	SG-P	782,708	0.088%	5,548	788,255	27.756%	1,540	218,785
544SG-U	544	SG-U	211,367	0.024%	1,498	212,865	27.756%	416	59,082
545SG-P	545	SG-P	838,761	0.095%	5,945	844,706	27.756%	1,650	234,453
545SG-U	545	SG-U	64,623	0.007%	458	65,081	27.756%	127	18,064
546SG	546	SG	29,298	0.003%	208	29,506	27.756%	58	8,189
548SG	548	SG	6,649,738	0.751%	47,132	6,696,870	27.756%	13,082	1,858,755
549OR	549	OR	17,084	0.002%	121	17,205	100.000%	121	17,205
549SG	549	SG	3,299,456	0.373%	23,386	3,322,843	27.756%	6,491	922,274
552SG	552	SG	1,157,934	0.131%	8,207	1,166,142	27.756%	2,278	323,669
553SG	553	SG	2,382,099	0.269%	16,884	2,398,983	27.756%	4,686	665,852
554SG	554	SG	95,644	0.011%	678	96,322	27.756%	188	26,735
556SG	556	SG	713,699	0.081%	5,059	718,758	27.756%	1,404	199,495
557ID	557	ID	43,293	0.005%	307	43,600	0.000%	-	-
557OR	557	OR	310	0.000%	2	313	100.000%	2	313
557SE	557	SE	-	0.000%	-	-	26.823%	-	-
557SG	557	SG	37,594,327	4.247%	266,464	37,860,791	27.756%	73,959	10,508,480
558WPSG	558WP	SG	1,412,700	0.160%	10,013	1,422,713	27.756%	2,779	394,882
558XPOR	558XP	OR	11,457	0.001%	81	11,539	100.000%	81	11,539
559SG	559	SG	413,824	0.047%	2,933	416,757	27.756%	814	115,673
560SG	560	SG	10,588,777	1.196%	75,052	10,663,829	27.756%	20,831	2,959,807
561SG	561	SG	13,469,348	1.522%	95,469	13,564,817	27.756%	26,498	3,764,993
562SG	562	SG	2,581,591	0.292%	18,298	2,599,889	27.756%	5,079	721,614
563SG	563	SG	656,855	0.074%	4,656	661,511	27.756%	1,292	183,606
566SG	566	SG	106,372	0.012%	754	107,126	27.756%	209	29,734
567SG	567	SG	184,960	0.021%	1,311	186,271	27.756%	364	51,701
568SG	568	SG	1,837,453	0.208%	13,024	1,850,476	27.756%	3,615	513,610
569SG	569	SG	3,509,752	0.397%	24,877	3,534,628	27.756%	6,905	981,056
570SG	570	SG	8,468,380	0.957%	60,023	8,528,403	27.756%	16,660	2,367,107
571SG	571	SG	4,995,651	0.564%	35,409	5,031,060	27.756%	9,828	1,396,400
572SG	572	SG	1,329	0.000%	9	1,338	27.756%	3	371
580CA	580	CA	991,812	0.112%	7,030	998,842	0.000%	-	-
580ID	580	ID	213,891	0.024%	1,516	215,407	0.000%	-	-
580OR	580	OR	1,430,924	0.162%	10,142	1,441,067	100.000%	10,142	1,441,067
580SNPD	580	SNPD	12,992,611	1.468%	92,090	13,084,701	25.578%	23,555	3,346,817
580UT	580	UT	742,195	0.084%	5,261	747,455	0.000%	-	-
580WA	580	WA	150,362	0.017%	1,066	151,428	0.000%	-	-
580WYP	580	WYP	168,926	0.019%	1,197	170,123	0.000%	-	-
580WYU	580	WYU	100,319	0.011%	711	101,030	0.000%	-	-
581SNPD	581	SNPD	17,716,137	2.001%	125,570	17,841,707	25.578%	32,118	4,563,568
582CA	582	CA	73,309	0.008%	520	73,828	0.000%	-	-
582ID	582	ID	121,691	0.014%	863	122,554	0.000%	-	-
582OR	582	OR	502,172	0.057%	3,559	505,731	100.000%	3,559	505,731
582UT	582	UT	1,295,070	0.146%	9,179	1,304,249	0.000%	-	-
582WA	582	WA	63,476	0.007%	450	63,926	0.000%	-	-
582WYP	582	WYP	335,994	0.038%	2,381	338,376	0.000%	-	-
583CA	583	CA	1,435,149	0.162%	10,172	1,445,321	0.000%	-	-
583ID	583	ID	562,494	0.064%	3,987	566,480	0.000%	-	-
583OR	583	OR	2,197,559	0.248%	15,576	2,213,135	100.000%	15,576	2,213,135
583UT	583	UT	4,787,083	0.541%	33,930	4,821,013	0.000%	-	-
583WA	583	WA	329,350	0.037%	2,334	331,684	0.000%	-	-
583WYP	583	WYP	1,018,316	0.115%	7,218	1,025,533	0.000%	-	-
583WYU	583	WYU	89,884	0.010%	637	90,521	0.000%	-	-
585SNPD	585	SNPD	287,045	0.032%	2,035	289,080	25.578%	520	73,941
586CA	586	CA	148,099	0.017%	1,050	149,149	0.000%	-	-
586ID	586	ID	177,925	0.020%	1,261	179,186	0.000%	-	-

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			Total Co.		Total Company			Oregon Allocated	
			Actual 12 Months Ended		Annualization	Annualized 12 Months Ended	Oregon	Annualization Adjustment Oregon	Annualized 12 Months Ended
Indicator	FERC	Factor	June 2025	% Of Total	Adjustment	June 2025	Allocation %	Allocated	June 2025
586OR	586	OR	1,219,888	0.138%	8,646	1,228,535	100.000%	8,646	1,228,535
586SNPD	586	SNPD	9,431	0.001%	67	9,498	25.578%	17	2,429
586UT	586	UT	1,041,784	0.118%	7,384	1,049,168	0.000%	-	-
586WA	586	WA	261,537	0.030%	1,854	263,390	0.000%	-	-
586WYP	586	WYP	320,793	0.036%	2,274	323,067	0.000%	-	-
586WYU	586	WYU	69,158	0.008%	490	69,649	0.000%	-	-
587CA	587	CA	663,340	0.075%	4,702	668,041	0.000%	-	-
587ID	587	ID	835,033	0.094%	5,919	840,952	0.000%	-	-
587OR	587	OR	5,657,228	0.639%	40,098	5,697,326	100.000%	40,098	5,697,326
587UT	587	UT	5,391,642	0.609%	38,215	5,429,857	0.000%	-	-
587WA	587	WA	1,280,067	0.145%	9,073	1,289,140	0.000%	-	-
587WYP	587	WYP	1,249,676	0.141%	8,858	1,258,533	0.000%	-	-
587WYU	587	WYU	96,391	0.011%	683	97,075	0.000%	-	-
588CA	588	CA	3,433	0.000%	24	3,457	0.000%	-	-
588ID	588	ID	3,523	0.000%	25	3,547	0.000%	-	-
588OR	588	OR	129,946	0.015%	921	130,867	100.000%	921	130,867
588SNPD	588	SNPD	26,894,609	3.038%	190,626	27,085,234	25.578%	48,758	6,927,886
588UT	588	UT	339,483	0.038%	2,406	341,889	0.000%	-	-
588WA	588	WA	20,263	0.002%	144	20,407	0.000%	-	-
588WYP	588	WYP	18,504	0.002%	131	18,635	0.000%	-	-
588WYU	588	WYU	304	0.000%	2	307	0.000%	-	-
589CA	589	CA	17,459	0.002%	124	17,582	0.000%	-	-
589ID	589	ID	19,326	0.002%	137	19,463	0.000%	-	-
589OR	589	OR	79,036	0.009%	560	79,597	100.000%	560	79,597
589UT	589	UT	342,361	0.039%	2,427	344,787	0.000%	-	-
589WA	589	WA	10,138	0.001%	72	10,209	0.000%	-	-
589WYP	589	WYP	61,966	0.007%	439	62,406	0.000%	-	-
589WYU	589	WYU	14,133	0.002%	100	14,233	0.000%	-	-
590CA	590	CA	129,923	0.015%	921	130,844	0.000%	-	-
590ID	590	ID	10,373	0.001%	74	10,446	0.000%	-	-
590OR	590	OR	1,244,761	0.141%	8,823	1,253,584	100.000%	8,823	1,253,584
590SNPD	590	SNPD	4,013,975	0.453%	28,451	4,042,425	25.578%	7,277	1,033,975
590UT	590	UT	850,836	0.096%	6,031	856,867	0.000%	-	-
590WA	590	WA	195,438	0.022%	1,385	196,823	0.000%	-	-
590WYP	590	WYP	521,134	0.059%	3,694	524,828	0.000%	-	-
591SNPD	591	SNPD	953	0.000%	7	960	25.578%	2	245
592CA	592	CA	422,052	0.048%	2,991	425,044	0.000%	-	-
592ID	592	ID	434,042	0.049%	3,076	437,119	0.000%	-	-
592OR	592	OR	3,582,900	0.405%	25,395	3,608,295	100.000%	25,395	3,608,295
592SNPD	592	SNPD	1,459,028	0.165%	10,341	1,469,369	25.578%	2,645	375,837
592UT	592	UT	2,199,912	0.249%	15,593	2,215,504	0.000%	-	-
592WA	592	WA	718,704	0.081%	5,094	723,798	0.000%	-	-
592WYP	592	WYP	711,126	0.080%	5,040	716,166	0.000%	-	-
593CA	593	CA	5,508,894	0.622%	39,046	5,547,940	0.000%	-	-
593ID	593	ID	3,998,683	0.452%	28,342	4,027,026	0.000%	-	-
593OR	593	OR	32,261,822	3.645%	228,668	32,490,490	100.000%	228,668	32,490,490
593SNPD	593	SNPD	3,254,765	0.368%	23,069	3,277,834	25.578%	5,901	838,407
593UT	593	UT	23,959,336	2.707%	169,821	24,129,157	0.000%	-	-
593WA	593	WA	5,417,108	0.612%	38,396	5,455,504	0.000%	-	-
593WYP	593	WYP	6,334,075	0.716%	44,895	6,378,970	0.000%	-	-
593WYU	593	WYU	853,357	0.096%	6,048	859,406	0.000%	-	-
594CA	594	CA	690,486	0.078%	4,894	695,380	0.000%	-	-
594ID	594	ID	677,562	0.077%	4,802	682,364	0.000%	-	-
594OR	594	OR	5,448,174	0.616%	38,616	5,486,790	100.000%	38,616	5,486,790
594SNPD	594	SNPD	4,576	0.001%	32	4,609	25.578%	8	1,179
594UT	594	UT	9,346,469	1.056%	66,247	9,412,716	0.000%	-	-
594WA	594	WA	1,265,508	0.143%	8,970	1,274,478	0.000%	-	-
594WYP	594	WYP	674,305	0.076%	4,779	679,085	0.000%	-	-
594WYU	594	WYU	159,210	0.018%	1,128	160,338	0.000%	-	-
595SNPD	595	SNPD	794,304	0.090%	5,630	799,934	25.578%	1,440	204,608
596CA	596	CA	46,342	0.005%	328	46,671	0.000%	-	-
596ID	596	ID	42,578	0.005%	302	42,880	0.000%	-	-
596OR	596	OR	584,396	0.066%	4,142	588,538	100.000%	4,142	588,538
596UT	596	UT	130,644	0.015%	926	131,570	0.000%	-	-
596WA	596	WA	40,471	0.005%	287	40,757	0.000%	-	-
596WYP	596	WYP	226,870	0.026%	1,608	228,478	0.000%	-	-
596WYU	596	WYU	50,285	0.006%	356	50,641	0.000%	-	-
597CA	597	CA	17,918	0.002%	127	18,045	0.000%	-	-
597ID	597	ID	14,933	0.002%	106	15,039	0.000%	-	-
597OR	597	OR	172,972	0.020%	1,226	174,198	100.000%	1,226	174,198
597SNPD	597	SNPD	(168,450)	-0.019%	(1,194)	(169,644)	25.578%	(305)	(43,392)
597UT	597	UT	153,965	0.017%	1,091	155,056	0.000%	-	-
597WA	597	WA	154,810	0.017%	1,097	155,907	0.000%	-	-
597WYP	597	WYP	19,819	0.002%	140	19,960	0.000%	-	-
597WYU	597	WYU	25,761	0.003%	183	25,943	0.000%	-	-
598OR	598	OR	23,182	0.003%	164	23,346	100.000%	164	23,346
598SNPD	598	SNPD	1,617,907	0.183%	11,468	1,629,375	25.578%	2,933	416,763

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Wages & Employee Benefits Amounts
Twelve-months Ended June 2025 Annualization

			Total Co.		Total Company			Oregon Allocated	
Indicator	FERC	Factor	Actual 12 Months Ended June 2025	% Of Total	Annualization Adjustment	Annualized 12 Months Ended June 2025	Oregon Allocation %	Annualization Adjustment Oregon Allocated	Annualized 12 Months Ended June 2025
598UT	598	UT	172	0.000%	1	173	0.000%	-	-
598WA	598	WA	7,926	0.001%	56	7,983	0.000%	-	-
901CN	901	CN	18,160,778	2.052%	128,721	18,289,499	30.140%	38,796	5,512,409
902CA	902	CA	350,158	0.040%	2,482	352,639	0.000%	-	-
902CN	902	CN	1,004,794	0.114%	7,122	1,011,916	30.140%	2,147	304,989
902ID	902	ID	127,066	0.014%	901	127,966	0.000%	-	-
902OR	902	OR	1,384,076	0.156%	9,810	1,393,886	100.000%	9,810	1,393,886
902UT	902	UT	1,814,641	0.205%	12,862	1,827,503	0.000%	-	-
902WA	902	WA	805,157	0.091%	5,707	810,864	0.000%	-	-
902WYP	902	WYP	1,067,981	0.121%	7,570	1,075,551	0.000%	-	-
902WYU	902	WYU	228,194	0.026%	1,617	229,812	0.000%	-	-
903CA	903	CA	68,107	0.008%	483	68,589	0.000%	-	-
903CN	903	CN	16,570,975	1.872%	117,453	16,688,428	30.140%	35,400	5,029,850
903ID	903	ID	102,546	0.012%	727	103,273	0.000%	-	-
903OR	903	OR	505,210	0.057%	3,581	508,791	100.000%	3,581	508,791
903UT	903	UT	2,795,519	0.316%	19,814	2,815,333	0.000%	-	-
903WA	903	WA	596,489	0.067%	4,228	600,716	0.000%	-	-
903WYP	903	WYP	275,835	0.031%	1,955	277,790	0.000%	-	-
903WYU	903	WYU	50,993	0.006%	361	51,355	0.000%	-	-
908CA	908	CA	193,798	0.022%	1,374	195,172	0.000%	-	-
908CN	908	CN	3,461,368	0.391%	24,534	3,485,902	30.140%	7,394	1,050,642
908ID	908	ID	30,519	0.003%	216	30,735	0.000%	-	-
908OR	908	OR	1,986,177	0.224%	14,078	2,000,255	100.000%	14,078	2,000,255
908OTHER	908	OTHER	8,395	0.001%	60	8,455	0.000%	-	-
908UT	908	UT	2,840,075	0.321%	20,130	2,860,205	0.000%	-	-
908WA	908	WA	409,895	0.046%	2,905	412,800	0.000%	-	-
908WYP	908	WYP	946,914	0.107%	6,712	953,625	0.000%	-	-
909CN	909	CN	2,459,070	0.278%	17,430	2,476,499	30.140%	5,253	746,411
909OR	909	OR	833	0.000%	6	839	100.000%	6	839
910CN	910	CN	87,871	0.010%	623	88,494	30.140%	188	26,672
920CA	920	CA	8,602	0.001%	61	8,663	0.000%	-	-
920OR	920	OR	241,938	0.027%	1,715	243,653	100.000%	1,715	243,653
920SO	920	SO	92,531,983	10.454%	655,855	93,187,837	27.909%	183,042	26,007,692
920UT	920	UT	0	0.000%	0	0	0.000%	-	-
920WYP	920	WYP	56,385	0.006%	400	56,784	0.000%	-	-
921SO	921	SO	40,126	0.005%	284	40,410	27.909%	79	11,278
922SO	922	SO	(23,271,753)	-2.629%	(164,947)	(23,436,700)	27.909%	(46,035)	(6,540,923)
928CA	928	CA	254	0.000%	2	256	0.000%	-	-
928ID	928	ID	113,383	0.013%	804	114,187	0.000%	-	-
928OR	928	OR	183,389	0.021%	1,300	184,689	100.000%	1,300	184,689
928SO	928	SO	271,296	0.031%	1,923	273,219	27.909%	537	76,252
928UT	928	UT	297,421	0.034%	2,108	299,529	0.000%	-	-
928WA	928	WA	43,913	0.005%	311	44,224	0.000%	-	-
928WYP	928	WYP	170,879	0.019%	1,211	172,090	0.000%	-	-
929SO	929	SO	(38,868,769)	-4.391%	(275,497)	(39,144,266)	27.909%	(76,888)	(10,924,731)
935CA	935	CA	365	0.000%	3	367	0.000%	-	-
935OR	935	OR	12,702	0.001%	90	12,792	100.000%	90	12,792
935SO	935	SO	2,246,721	0.254%	15,924	2,262,645	27.909%	4,444	631,479
935WA	935	WA	349	0.000%	2	351	0.000%	-	-
935WYP	935	WYP	936	0.000%	7	943	0.000%	-	-
Utility Labor			560,245,111	63.29%	3,970,946	564,216,057		1,195,187	**169,819,424**
			Ref IR_5.9		Ref IR_5.9	Ref IR_5.9			**Ref IR_5.1**
Non-Utility/Capital			324,915,286	36.71%	2,302,958	327,218,245			
Total			885,160,397	100.00%	6,273,904	891,434,302			

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Incremental Non-Capitalized Labor Expenses

Description	Actual 12 Months Ended June 2025	Annualized 12 Months Ended June 2025	Adjustment	Ref.
Regular Ordinary Time	530,920,670	548,238,557	17,317,887	
Overtime	95,280,751	98,388,675	3,107,924	
Premium Pay	13,048,774	13,474,407	425,633	
Subtotal for Escalation	**639,250,195**	**660,101,639**	**20,851,444**	IR_5.11
Unused Leave	6,101,804	6,300,836	199,032	IR_5.12
Temporary/Contract Labor	-	-	-	
Severance Pay	347,284	347,284	-	
Other Salary/Labor Costs	6,627,493	6,627,493	-	
Joint Owner Cutbacks	(1,186,016)	(1,224,702)	(38,686)	IR_5.12
Subtotal Bare Labor	**651,140,759**	**672,152,550**	**21,011,790**	
Annual Incentive Plan	28,930,642	14,465,321	(14,465,321)	IR_5.12
Total Incentive	**28,930,642**	**14,465,321**	**(14,465,321)**	
Overtime Meals	1,856,975	1,856,975	-	
Bonus and Awards	1,452,443	726,221	(726,221)	IR_5.12
Physical Exam	77,999	77,999	-	
Education Assistance	173,717	173,717	-	
Mining Salary/Benefit Credit	(190,598)	(190,598)	-	
Total Other Labor	**3,370,537**	**2,644,315**	**(726,221)**	
Subtotal Labor and Incentive	**683,441,938**	**689,262,186**	**5,820,248**	
Pensions	4,623,176	4,623,176	-	
SERP Plan	-	-	-	
Post Retirement Benefits	2,018,062	2,018,062	-	
Post Employment Benefits	4,859,295	4,859,295	-	
Total Pensions	**11,500,532**	**11,500,532**	**-**	
Pension Administration	297,116	297,116	-	
Medical	69,764,415	69,764,415	-	
Dental	3,896,237	3,896,237	-	
Vision	419,177	419,177	-	
Life	299,920	299,920	-	
401(k)	54,969,694	54,969,694	-	
401(k) Administration	585	585	-	
Accidental Death & Disability	28,127	28,127	-	
Long-Term Disability	4,256,463	4,256,463	-	
Worker's Compensation	1,904,499	1,904,499	-	
Other Salary Overhead	2,241,506	2,241,506	-	
Total Benefits	**138,077,738**	**138,077,738**	**-**	
Subtotal Pensions and Benefits	**149,578,270**	**149,578,270**	**-**	
Payroll Tax Expense	47,452,603	47,906,259	453,656	IR_5.13
Payroll Tax Expense-Unemployment	4,687,587	4,687,587	-	
Total Payroll Taxes	**52,140,189**	**52,593,846**	**453,656**	
Total Labor	**885,160,397**	**891,434,302**	**6,273,904**	
Non-Utility and Capitalized Labor	324,915,286	327,218,245	2,302,958	
Total Utility Labor	**560,245,111**	**564,216,057**	**3,970,946**	
	Ref IR_5.8	**Ref IR_5.8**	**Ref IR_5.8**	

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Annualization of June 2025 Wages Expenses
$ thousands

Labor (12 Months Ended June 2025 in 1,000's)

Account Desc.	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Total
Regular Ordinary Time	44,252	42,436	41,113	45,674	41,562	43,337	47,783	43,024	43,917	46,259	46,665	44,899	530,921
Overtime	11,052	8,249	6,740	8,657	7,850	8,359	7,399	8,499	7,577	6,392	7,051	7,457	95,281
Premium Pay	1,627	1,648	1,015	1,318	1,120	933	788	861	936	754	1,036	1,012	13,049
Grand Total	**56,932**	**52,333**	**48,867**	**55,649**	**50,532**	**52,629**	**55,970**	**52,385**	**52,429**	**53,404**	**54,753**	**53,368**	**639,250**

Labor (12 Months Ended June 2025 in 1,000's)

Group Code	Labor Group	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Total
2	Officer/Exempt	20,454	20,026	18,300	21,360	19,607	20,006	23,588	20,559	21,928	21,911	23,501	21,607	252,847
3	IBEW 125	5,257	4,825	4,320	5,089	4,520	4,334	4,558	4,500	4,397	4,295	4,512	4,519	55,125
4	IBEW 659	7,187	4,673	4,508	5,454	5,435	5,354	5,048	6,282	4,999	4,612	4,894	5,138	63,584
5	UWUA 197	303	201	205	270	310	372	262	255	292	227	221	225	3,144
8	UWUA 127	4,584	4,240	4,409	4,673	4,306	4,954	4,698	4,297	4,378	4,818	4,218	4,548	54,124
9	IBEW 57 WY	92	91	84	119	79	84	83	80	75	94	87	84	1,051
11	IBEW 57 PD	12,694	12,181	11,073	12,399	10,358	11,009	11,240	10,671	10,340	10,870	10,880	11,515	135,229
12	IBEW 57 PS	3,977	3,808	3,804	3,965	3,696	4,127	4,049	3,573	3,727	4,051	3,939	3,877	46,594
13	PCCC Non-Exempt	517	491	478	462	436	473	510	456	462	462	462	496	5,705
15	IBEW 57 CT	380	361	372	391	413	429	397	344	369	586	512	449	5,002
16	IBEW 77	131	135	134	125	125	176	157	136	155	165	147	146	1,731
18	Non-Exempt	1,356	1,301	1,182	1,342	1,246	1,312	1,380	1,234	1,307	1,314	1,380	764	15,116
Grand Total		**56,932**	**52,333**	**48,867**	**55,649**	**50,532**	**52,629**	**55,971**	**52,385**	**52,429**	**53,404**	**54,753**	**53,368**	**639,252**

Annualization Increase

Group Code	Labor Group	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	
2	Officer/Exempt							10.95%						(1)
3	IBEW 125								2.50%					(1)
4	IBEW 659											4.00%		(1)
5	UWUA 197												2.50%	(1)
8	UWUA 127				5.50%									(1)
9	IBEW 57 WY	4.50%												(1)
11	IBEW 57 PD								2.50%					(1)
12	IBEW 57 PS								2.50%					(1)
13	PCCC Non-Exempt							10.95%						(1)
15	IBEW 57 CT								2.50%					(1)
16	IBEW 77		3.00%						3.00%					(1)
18	Non-Exempt							10.95%						(1)

(1) Overall actual.

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Annualization of June 2025 Wages Expenses
$ thousands
Annualized Labor June 2025 (In 1,000's)

Group Code	Labor Group	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Total
2	Officer/Exempt	22,694	22,219	20,304	23,699	21,754	22,196	23,588	20,559	21,928	21,911	23,501	21,607	265,960
3	IBEW 125	5,388	4,946	4,428	5,216	4,633	4,442	4,671	4,500	4,397	4,295	4,512	4,519	55,948
4	IBEW 659	7,475	4,860	4,688	5,672	5,653	5,568	5,250	6,533	5,199	4,796	4,894	5,138	65,726
5	UWUA 197	310	206	210	277	318	382	269	261	300	233	227	225	3,217
8	UWUA 127	4,837	4,473	4,652	4,673	4,306	4,954	4,698	4,297	4,378	4,818	4,218	4,548	54,852
9	IBEW 57 WY	92	91	84	119	79	84	83	80	75	94	87	84	1,051
11	IBEW 57 PD	13,011	12,486	11,350	12,709	10,617	11,284	11,521	10,671	10,340	10,870	10,880	11,515	137,253
12	IBEW 57 PS	4,077	3,903	3,899	4,064	3,789	4,230	4,151	3,573	3,727	4,051	3,939	3,877	47,280
13	PCCC Non-Exempt	573	545	530	512	484	525	510	456	462	462	462	496	6,018
15	IBEW 57 CT	390	370	381	400	423	440	407	344	369	586	512	449	5,071
16	IBEW 77	138	139	138	129	129	181	161	136	155	165	147	146	1,764
18	Non-Exempt	1,505	1,443	1,311	1,489	1,382	1,455	1,380	1,234	1,307	1,314	1,380	764	15,963
Grand Total		**60,489**	**55,681**	**51,974**	**58,960**	**53,567**	**55,742**	**56,690**	**52,642**	**52,636**	**53,594**	**54,759**	**53,368**	**660,102**

Ref IR_5.9

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Annualization of June 2025 Other Labor Costs

Composite Labor Increases

		Ref.
Regular Time/Overtime/Premium Pay Annualize - Actual	639,250,195	IR_5.9
Regular Time/Overtime/Premium Pay Annualize - Annualized	660,101,639	IR_5.9
% Increase-Annualized	3.26%	

Miscellaneous Bare Labor Escalation

Description	June 2025 Actual	Annual Increase	June 2025 Annualized
Unused Leave	6,101,804	3.26%	6,300,836
Joint Owner Cutbacks	(1,186,016)	3.26%	(1,224,702)
	4,915,788		5,076,134

Bonus and Awards Calculation:

Description	June 2025 Actual	Annualized Adjustment	[2] Remove 50%	
Bonus and Awards Calculation	1,452,443	1,452,443	726,221	
Year	[3] Exempt Bonus	Non-Exempt and Union Bonus	Total	
2024	456,133	84,168	540,301	
2023	1,685,409	692,413	2,377,822	
2022	1,288,716	419,961	1,708,677	
2021	41,767	141,126	182,893	
2020	660,585	989,763	1,650,348	
	4,132,610	2,327,430	6,460,040	Total
	826,522	465,486	**1,292,008**	5-Year Avg.
			Above	

Annual Incentive Plan Escalation

Description	June 2025 Actual	Annualized Adjustment	[2] Remove 50%
Annual Incentive Plan Compensation	28,930,642	28,930,642	14,465,321

Year	*[4] Exempt Wages*	*[3] AIP*	*%*
2024	232,396,348	19,901,900	8.56%
2023	215,714,914	25,603,828	11.87%
2022	193,734,722	31,894,180	16.46%
2021	188,363,246	28,389,339	15.07%
2020	196,651,699	27,916,645	14.20%
5-Year Total	1,026,860,928	133,705,892	13.02%
2027	-	-	13.02%

[1] Compound Annual Growth Rate
[2] Per Commission Order in GRC UE-433, Order No. 24-447
[3] Per Commission Order in GRC UE-374, Order No. 20-473
[4] Net of Named Executive Officers (NEO's) Compensation

PacifiCorp
Oregon General Rate Case - December 2027
Interim Rate Proposal
Payroll Tax Adjustment Calculation

	Line No.	Ref	Social Security	Medicare	Total FICA Tax	Ref
FICA Calculated on June 2025 Annualized Labor						
Annualized Wages Adjustment	a		20,851,444	20,851,444		IR_5.9
Annualized Incentive Adjustment	b		(14,465,321)	(14,465,321)		IR_5.9
	c	a + b	6,386,123	6,386,123		
Percentage of eligible wages	d		91.19%	100.00%		
Total eligible wages	e	c * d	5,823,510	6,386,123		
Tax rate	f		6.20%	1.45%		
Tax on eligible wages	g	e * f	361,058	92,599		
Total FICA Tax on Annualized Labor		g	**361,058**	**92,599**	**453,656**	IR_5.9

Docket No. UE 470
Exhibit PAC/900
Witness: Kenneth Lee Elder, Jr.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Kenneth Lee Elder, Jr.

May 2026

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II. UNBUNDLED CLASS REVENUE REQUIREMENTS 2
III. MARGINAL COST STUDY 5
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ATTACHED EXHIBITS

Exhibit PAC/901—Unbundled Results of Operations - Summary and Detail

Exhibit PAC/902—Functionalized Oregon Results of Operations Report

Exhibit PAC/903—Functional Factors

Exhibit PAC/904—Ancillary Services Revenue Requirement

Exhibit PAC/905—Oregon Marginal Cost of Service Study Summary

Exhibit PAC/906—Unbundled Revenue Requirement Allocation

Exhibit PAC/907—Oregon Marginal Cost of Service Study

Exhibit PAC/908—Residential Basic Charge Calculation

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power.

A. My name is Kenneth Lee Elder, Jr. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing and Tariff Policy.

Q. Please describe your education and professional background.

A. I have a Bachelor's Degree in Agriculture Business from Tarleton State University and a Master's Degree in Agricultural and Resource Economics from Colorado State University. I have been employed by PacifiCorp since July 2016 where I have managed load forecasting and load research. From 2008 through 2016, I was an economist for a natural resource consulting firm. From 2004 through 2008, I was an economist for the University of Alaska Fairbanks. In May 2025, I assumed my current position.

Q. What are your responsibilities?

A. I am responsible for regulated retail rates, tariff policy, and cost of service analysis in the company's six-state service territory.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified for the company in regulatory proceedings in Oregon, Washington, Utah, Wyoming, and Idaho.

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

A. I present the company's proposed revenue requirement for each of the unbundled service categories and the supporting Marginal Cost Study. I also discuss the Power

Act, Oregon House Bill (HB) 3546, 83rd Legislature (2025) and how it relates to this filing.

II. UNBUNDLED CLASS REVENUE REQUIREMENTS

Q. Please identify Exhibit PAC/901 and explain what it shows.

A. Exhibit PAC/901 page 1 shows the company's proposed revenue requirement for each of the unbundled service categories required by OAR 860-038-0200: Generation (also referred to as Production), Transmission, Distribution, Ancillary Services, Consumer Services—Billing, Consumer Services—Metering, Consumer Services—Other, Retail Services, and Investment in Public Purposes.

No revenue requirement is shown for the Retail Services or Investment in Public Purposes categories. The company separately accounts for the costs associated with unregulated retail activities and is not seeking regulatory cost recovery for these items. Public purpose revenues are collected under a separate tariff.

Q. How was the revenue requirement determined for each of the unbundled categories?

A. Rate base balances, revenues, and expenses were either assigned or allocated to unbundled categories in accordance with Oregon regulations.[1] Traditional revenue requirement methodology (i.e., recovery of costs plus a return on rate base) was then used to determine a revenue requirement for each category. Rate base balances, revenues, and expenses are from PacifiCorp's Oregon Results of Operations Report, as prepared under the direction of PacifiCorp witness Shelley E. McCoy.

[1] *See* OAR 860-038-0200.

The application of PacifiCorp's proposed rate increase is shown on page 2 of Exhibit PAC/901.

Q. Please identify Exhibit PAC/902 and explain what it shows.

A. Page 1 of Exhibit PAC/902 is the summary page from PacifiCorp's December 2027 Functionalized Oregon Results of Operations Report (Functionalized Oregon Results of Operations Report) and is the basis for the unbundled revenue requirement in Exhibit PAC/901. It separates the results of operations into the unbundled categories identified above.

Q. Please explain how the rate base balances, revenues and expenses in the Functionalized Oregon Results of Operations Report were apportioned among the unbundled categories.

A. The detail of PacifiCorp's Functionalized Results of Operations Report by Federal Energy Regulatory Commission account is found on page 2 through 35 of Exhibit PAC/902. The functionalization procedures in this case are consistent with those approved in Order No. 01-787 and implemented in Advice No. 01-020. Functional factors employed in the development of these results are provided in Exhibit PAC/903.

Q. How did PacifiCorp determine the revenue requirement for Ancillary Services?

A. The revenue requirement for Ancillary Services was estimated by applying PacifiCorp's prices for Regulation and Frequency Response Service, Spinning Reserve Service, and Supplemental Reserve Service to the relevant billing determinants of PacifiCorp's total Oregon retail load. This is shown in Exhibit PAC/904. The costs associated with providing these services are included in

the Generation function. The estimated revenue for Ancillary Services is treated as an offsetting revenue credit against the Generation revenue requirement.

Q. Please identify Exhibit PAC/905 and explain what it shows.

A. Exhibit PAC/905 contains a summary from the Marginal Cost Study that the company prepared for this case. The Marginal Cost Study is described in more detail later in my testimony.

Q. Please identify Exhibit PAC/906 and explain what it shows.

A. Page 1 of Exhibit PAC/906 is the derivation of functionalized class revenue requirements and a comparison with current revenues. This exhibit is based on the results of both the Functionalized Oregon Results of Operations Report and the Marginal Cost Study. Present class revenues are shown on line 1. Full long-run marginal costs for each customer class, separated by function, are shown on lines 2 through 10. Lines 11 through 21 show each class share of total marginal costs for each function. Lines 22 through 33 show the assignment of functional revenue requirement. The total revenue requirement for each unbundled category, as determined earlier, is shown in the total column. The total for each function is then allocated to a particular customer class based on that class share of total marginal cost for that function. For example, the residential class accounts for 37.95 percent of generation marginal costs and is assigned 37.95 percent of the generation revenue requirement. Regulatory and franchise fees are considered part of the distribution function; however, for the purpose of assigning cost responsibility, the fees have been broken out separately. Regulatory and franchise fees have been assigned on the basis

of class revenue. Lines 34 through 36 compare the total revenue requirement by class to the present class revenues collected from base rates as shown on line 1.

Q. Please explain what is shown on pages 2 and 3 of Exhibit PAC/906.

A. Pages 2 and 3 of Exhibit PAC/906 provide a reconciliation between Operating Revenues and Target Revenue Requirement, as shown on page 1 of this exhibit, with those shown in Exhibits PAC/901 and PAC/902. Not all customer classes are included in the Marginal Cost Study. Page 2 of Exhibit PAC/906 accounts for all Oregon test period revenue sources. Page 3 accounts for all revenue sources included in the Target Revenue Requirement.

III. MARGINAL COST STUDY

Q. Please describe PacifiCorp's Marginal Cost Study that accompanies this filing.

A. The Marginal Cost Study is found in Exhibit PAC/907. This study shows, by customer class, PacifiCorp's marginal cost of resources required to produce one additional unit of electricity or to add one additional customer. Exhibit PAC/907 contains a marginal cost study procedures narrative, various summary tables, and supporting calculations.

Q. Is this Marginal Cost Study similar to studies the company has previously filed?

A. Except for the methodology for calculating marginal generation costs, which is discussed later in my testimony, this study is similar to the cost-of-service study the company presented in Docket UE 433, PacifiCorp's 2025 rate case.

Q. How are marginal costs calculated?

A. One-year marginal costs include only changes in operating costs while 10-year and 20-year marginal costs also include the cost of expanding facilities. The costs of these added facilities result in long-run costs that are higher than short-run costs. Short-run

costs include only one year of generation energy costs and some billing costs. They do not include any demand-related generation, transmission or distribution costs. Exhibit PAC/907 includes a detailed description of marginal cost procedures on pages 1 through 11.

Q. Please describe the marginal cost summary tables included in pages 12 through 19 of Exhibit PAC/907.

A. Tables 1 and 2 of Exhibit PAC/907 summarize the one-year, 10-year and 20-year marginal costs on a mills-per-kilowatt-hour or dollars-per-customer basis. Table 3 summarizes the unit costs based on the results of the 20-year long-run marginal cost study. Unit costs are shown for generation, transmission, distribution and various customer service functional categories. Table 3 also includes energy usage, peak demand, and number of customers by customer class for the 12-month period ending December 31, 2027, test period. This information is used to calculate the annual long-run marginal costs by class shown at the bottom of Table 3.

Q. What changes does the company propose for marginal generation costs?

A. In the 2025 rate case, PacifiCorp received feedback from parties to use generation resources from its integrated resource plan (IRP) preferred portfolio in order to model the energy component of its generation marginal cost study, as opposed to only using market purchases, in its next general rate case.[2]

[2] See pages 13 through 15 of OPUC Witness Mr. Bret Steven's direct testimony in Docket No. UE-433.

Q. Please describe how PacifiCorp developed its marginal generation costs for this proceeding.

A. PacifiCorp proposes using data from the company's October 2025 energy efficiency utility data submission in Docket UM 1893 as the basis for the development of the marginal generation costs in this case. This data submission included information on several capacity and energy resources that were part of the company's 2025 IRP preferred portfolio. From these resources, PacifiCorp proposes a capacity and an energy resource representative of what the company expects to procure to serve Oregon customers in the near term.

For the capacity resource, PacifiCorp proposes a 200 megawatts (MW), 4-hour battery in Central Oregon with a commercial operations date of 2028, adjusted for its capacity contribution and energy (dispatch) benefits consistent with the Docket UM 1893 data submission. For the energy resource, PacifiCorp proposes a utility-scale solar resource in Central Oregon with a commercial operations date of 2030, adjusted based on its capacity contribution and the capacity cost. Exhibit PAC/907 summarizes these costs on Table 4 and provides a detailed calculation on the "Generation Demand and Energy" Table.

Q. How are transmission costs calculated?

A. Transmission costs are based on a five-year analysis of forecasted expenditures. Expenditures identified as growth-related are used to develop marginal transmission costs. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand. Bulk power lines are classified both to demand and

energy in the same proportions as the long-run marginal costs of generation resources. Marginal transmission costs are summarized on Table 5 of Exhibit PAC/907.

Q. Please provide a general overview of how marginal distribution costs are determined.

A. Table 6 of Exhibit PAC/907 provides a unit cost summary by class and load size of marginal distribution costs. Distribution costs are classified into three components: (1) demand-related, shown in annual dollars per kilowatt (kW); (2) commitment-related, shown in annual dollars per customer; and (3) billing-related, shown in annual dollars per customer. Commitment-related distribution costs consist of the costs of transformers, poles and conductors that are not determined by the level of demand customers place on the system. Demand-related distribution costs include additional costs of larger transformers, substations, poles, and conductor with sufficient capacity to serve the level of demand a customer class places on the system.

Q. Please describe how the marginal costs of distribution line transformers are calculated.

A. Marginal transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of PacifiCorp's commonly installed transformers. Commitment and demand costs are separated by this statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Q. Please describe how the marginal costs of distribution circuits are calculated.

A. Marginal costs of distribution poles and wires are calculated using PacifiCorp's Distribution Circuit Model. The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics and current cost estimates for Oregon. Customer locations are based on actual customer distances from the substation. The results are segregated into commitment-related and demand-related costs for each customer class. Exhibit PAC/907 includes a detailed description of the updated circuit model.

Q. How are substation marginal costs calculated?

A. Marginal substation costs are determined using the per cost of substation additions being considered for a five-year period. The cost per kW is determined by dividing the growth-related distribution substation investment in the capital budget horizon by the related increase in substation capacity. Substation marginal costs are classified entirely to demand and are allocated to customer classes based on the distribution peak load for each class weighted by the load of substations peaking in each month.

Q. What is included in the service drop category?

A. The service drop category includes the marginal cost of service drops with associated operation and maintenance (O&M). Current typical installed costs for service drops are determined for each customer load size.

Q. What is included in the metering category?

A. The metering category includes the marginal cost of metering equipment with associated O&M. Current typical installed metering costs are determined for each customer load size by analyzing service requirements, such as single- or three-phase service and voltage level. Meter O&M is based on historical expenditures.

Q. What is included in the billing and customer service/other categories?

A. This category includes the costs of billing, payment processing and debt recovery, meter reading expense and all the remaining customer accounting and customer service activities. Marginal meter reading expense is assumed to be zero because Advanced Metering Infrastructure has been deployed for almost all customers. Customer accounting and customer service expense are based on historical expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

Q. Please identify Exhibit PAC/908 and explain what it shows.

A. Exhibit PAC/908 shows each of the residential annual billing- and commitment-related costs,[3] which total to $470.62 or about $39.22 per month. In addition to providing this information for the residential class as a whole, this exhibit also illustrates how these costs differ for single-family and multi-family residential customers. For example, the costs are higher for single-family residential customers, at about $44.51 per month, and lower for multi-family customers, at about $24.05 per month. To provide this, PacifiCorp differentiated the poles and conductor cost

[3] The "$/Customer" costs for Schedule 4 from Exhibit PAC/907, Table 3.

categories by accounting for the difference in single- and multi-family customer distances from substations, and the line transformer cost category by accounting for the difference in single-family and multi-family customers per transformer.

Exhibit PAC/908 shows that, at the present prices of $14 for single-family and $8 for multi-family customers, the company's basic charge falls far short of cost. PacifiCorp witness Judith M. Ridenour refers to this exhibit in her testimony and proposes increasing the single-family basic charge to $17 and the multi-family basic charge to $9.

IV. HOUSE BILL 3546 (POWER ACT)

Q. What is House Bill 3546?

A. Oregon HB 3546, effective June 16, 2025, requires the Public Utility Commission of Oregon to establish a separate tariff and service classification for "Large Energy Use Facilities" (Facilities), defined as those Facilities that are engaged in providing services described under code 518210 of 2022 North American Industry Classification System that use or can use 20 MW or more of electricity.[4]

Q. Does HB 3546 specify how to classify service for large energy use facilities?

A. Yes. HB 3546 requires that the classification of service must be separate and distinct from other commercial or industrial retail electricity consumers, and that the classification of service must have its own tariff schedule.

This tariff schedule must either (1) allocate the costs of serving the class of retail electricity consumers that are large energy use facilities to the class in a manner that is equal or proportional to the cost of serving the class, or (2) directly assign the

[4] Code 518210 of the 2022 North American Industry Classification System includes businesses that are computing infrastructure providers, data processing, web hosting, and related services.

costs of serving a retail consumer that is a large energy use facility to the retail electricity consumer.

Q. Have you addressed the requirements of HB 3546 within this filing?

A. No. PacifiCorp will address the requirements of HB 3546 for new Facilities in Docket UE 463. The company plans to address the requirements of HB 3546 for existing Facilities in a future proceeding.

V. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 470
Exhibit PAC/901
Witness: Kenneth Lee Elder, Jr.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Kenneth Lee Elder, Jr.

Unbundled Results of Operations - Summary and Detail

May 2026

Combined GRC and TAM Functionalized Revenue Requirement 12 Months Ending December 2027 Forecast		
Production	$	888,823,739
Transmission	$	355,077,127
Distribution	$	580,871,280
Ancillary	$	30,913,774
Customer Billing	$	6,037,089
Customer Metering	$	21,930,848
Customer Other	$	15,690,727
Total	$	1,899,344,584

Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ending December 2027 Forecast

	Total	Production	Transmission	Distribution	Distribution-Lighting	Ancillary	Billing	Metering	Cust. Serv./ Other	Franchise Fees
Earned $000	1,793,305	867,534	312,941	483,725	3,165	30,914	5,817	20,456	15,478	53,275
Target Increase	77,260	15,880	31,430	28,313	214	-	164	1,100	159	-
Add										
Uncollectible Expense	661	133	263	237	2	-	1	9	1	15
Franchise Tax	2,435									2,435
Other Revenue Based Taxes	495	99	197	177	1	-	1	7	1	11
Income Taxes - State	4,651	956	1,892	1,704	13	-	10	66	10	-
Income Taxes - Federal	20,538	4,221	8,355	7,526	57	-	44	292	42	-
Total Increase	106,039	21,289	42,136	37,957	288	-	220	1,475	213	2,462
Target $000	1,899,345	888,824	355,077	521,682	3,452	30,914	6,037	21,931	15,691	55,737

Docket No. UE 470
Exhibit PAC/902
Witness: Kenneth Lee Elder, Jr.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Kenneth Lee Elder, Jr.

Functionalized Oregon Results of Operations Report

May 2026

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027									
	Total	**Production**	**Transmission**	**Distribution**	**Dist-Lighting**	**Ancillary**	**Billing**	**Metering**	**Cust Service**
General Business Revenues	1,793,305,491	867,534,340	312,940,883	536,654,189	3,511,234	30,913,774	5,817,389	20,455,741	15,477,939
Special Sales	54,006,161	54,006,161	-	-	-	-	-	-	-
Other Operating Revenues	74,085,068	38,902,144	51,328,627	7,569,887	2,392	(30,913,774)	6,875,017	139,049	181,727
Total Operating Revenues	1,921,396,720	960,442,645	364,269,510	544,224,076	3,513,627	-	12,692,406	20,594,790	15,659,667
Steam Production	264,348,177	264,348,177	-	-	-	-	-	-	-
Nuclear Production	-	-	-	-	-	-	-	-	-
Hydro Production	13,378,082	13,378,082	-	-	-	-	-	-	-
Solar Production	232,196	232,196	-	-	-	-	-	-	-
Wind Production	10,283,870	10,283,870	-	-	-	-	-	-	-
Other Renewable Production	1,997,903	1,997,903	-	-	-	-	-	-	-
Other Power Supply	449,391,626	449,391,626	-	-	-	-	-	-	-
Transmission	91,307,111	231,002	91,076,110	-	-	-	-	-	-
Distribution	125,776,662	-	-	122,646,644	1,025,433	-	-	2,104,585	-
Customer Accounts	32,131,875	6,931,313	1,555,395	2,401,563	15,426	-	7,938,662	5,258,697	8,030,820
Customer Service	5,324,067	-	-	2,328,091	-	-	-	-	2,995,976
Sales	-	-	-	-	-	-	-	-	-
Administrative & General	140,886,076	19,065,087	8,228,684	105,774,509	219,553	-	1,687,589	3,827,884	2,082,770
Total O & M Expenses	1,135,057,645	765,859,255	100,860,189	233,150,806	1,260,412	-	9,626,250	11,191,166	13,109,566
Depreciation	337,794,580	183,097,711	62,551,329	84,998,805	921,655	-	1,924,789	2,790,017	1,510,274
Amortization	(295,207)	5,613,643	850,991	(6,545,578)	47	-	279	(214,980)	391
Taxes Other Than Income	112,881,934	26,066,375	16,191,960	69,412,552	125,086	-	293,880	567,960	224,122
Income Taxes - Federal	(60,628,691)	(83,492,597)	6,982,791	13,729,463	356,466	-	175,121	1,489,051	131,015
Income Taxes - State	5,141,589	3,189,815	715,798	1,105,208	7,099	-	34,069	47,697	41,903
Income Taxes - Def Net	9,027,360	(18,340,059)	20,592,356	8,034,804	(219,104)	-	(173,355)	(723,834)	(143,448)
Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-
Misc Revenue & Expense	(104,716)	(175,342)	(89,203)	159,829	-	-	-	-	-
Total Operating Expenses	1,538,874,495	881,818,801	208,656,212	404,045,889	2,451,661	-	11,881,033	15,147,077	14,873,822
Electric Plant in Service	11,726,376,909	4,529,570,832	3,412,907,789	3,524,816,002	32,640,446	-	55,415,024	133,430,517	37,596,300
Plant Held for Future Use	-	-	-	-	-	-	-	-	-
Misc Deferred Debits	93,002,614	70,372,746	4,458,933	14,717,647	162,646	-	961,036	984,684	1,344,922
Elec Plant Acq Adj	684,215	684,215	-	-	-	-	-	-	-
Pensions	-	-	-	-	-	-	-	-	-
Prepayments	51,058,541	19,084,911	4,748,262	22,052,181	243,681	-	1,439,659	1,475,193	2,014,653
Fuel Stock	89,834,980	89,834,980	-	-	-	-	-	-	-
Material & Supplies	239,908,978	174,560,477	3,343,599	60,043,522	-	-	-	1,961,380	-
Working Capital	62,523,353	25,821,963	6,067,540	25,349,737	243,371	-	1,468,026	1,527,547	2,045,169
Weatherization Loans	-	-	-	-	-	-	-	-	-
Miscellaneous Rate Base	(14,356,267)	(14,356,267)	-	-	-	-	-	-	-
Total Electric Plant	12,249,033,325	4,895,573,857	3,431,526,123	3,646,979,090	33,290,143	-	59,283,745	139,379,322	43,001,045
Accum Prov For Depr	(4,896,570,165)	(2,475,088,425)	(837,749,867)	(1,435,191,881)	(16,515,704)	-	(48,494,306)	(53,372,445)	(30,157,537)
Accum Prov For Amort	(45,207,495)	(28,038,310)	(13,478,971)	(4,380,293)	(42,754)	-	408,891	36,361	287,580
Accum Def Income Taxes	(778,022,691)	(776,489,070)	(27,471,979)	25,361,649	159,637	-	1,238,518	467,419	(1,288,865)
Unamortized ITC	(26,013)	(9,550)	(2,075)	(11,653)	(129)	-	(761)	(780)	(1,065)
Customer Adv for Const	(88,409,248)	-	(78,355,133)	(9,661,527)	(74,549)	-	-	(318,038)	-
Customer Service Deposits	-	-	-	-	-	-	-	-	-
Misc. Rate Base Deductions	(354,993,731)	(365,068,753)	1,288,777	7,093,899	78,874	-	472,597	479,498	661,376
Total Rate Base Deductions	(6,163,229,344)	(3,644,694,108)	(955,769,250)	(1,416,789,807)	(16,394,624)	-	(46,375,061)	(52,707,984)	(30,498,511)
Total Rate Base	6,085,803,981	1,250,879,749	2,475,756,873	2,230,189,283	16,895,520	-	12,908,684	86,671,338	12,502,534

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC Account	**Description**	**Functional Factor**	**Allocator**	**Total**	**Production**	**Transmission**	**Distribution**	**Dist-Lighting**	**Ancillary**	**Billing**	**Metering**	**Cust Service**
440	Residential Sales		S	819,709,408								
442	Commercial & Industrial Sales		S	969,757,928								
444	Lighting Sales		S	3,838,155								
	Total General Business Revenues			1,793,305,491	867,534,340	312,940,883	536,654,189	3,511,234	30,913,774	5,817,389	20,455,741	15,477,939
447	Sales for Resale-Non NPC											
		P	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
447NPC	Sales for Resale - NPC											
		P	S	54,006,161	54,006,161	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		P	SG	(0)	(0)	-	-	-	-	-	-	-
				54,006,161	54,006,161	-	-	-	-	-	-	-
	Total Sales for Resale			54,006,161	54,006,161	-	-	-	-	-	-	-
449	Provision for Rate Refund	P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Sales from Electricity			1,847,311,652	921,540,501	312,940,883	536,654,189	3,511,234	30,913,774	5,817,389	20,455,741	15,477,939
450	Forfeited Discounts & Interest											
		C_BILLING	S	6,625,546	-	-	-	-	-	6,625,546	-	-
		C_BILLING	SO	-	-	-	-	-	-	-	-	-
				6,625,546	-	-	-	-	-	6,625,546	-	-
451	Misc Electric Revenue											
		CSS_SYS	S	551,000	-	-	-	-	-	244,277	128,567	178,157
		GP-TC	SG	-	-	-	-	-	-	-	-	-
		GP-TC	SO	18,978	7,522	5,630	5,439	43	-	93	188	64
				569,979	7,522	5,630	5,439	43	-	244,370	128,754	178,221
453	Water Sales											
		P	SG	1,636	1,636	-	-	-	-	-	-	-
				1,636	1,636	-	-	-	-	-	-	-
454	Rent of Electric Property											
		D	S	7,261,847	-	-	7,261,847	-	-	-	-	-
		T	SG	616,029	-	616,029	-	-	-	-	-	-
		GP-TC	SO	1,041,645	412,877	309,001	298,516	2,349	-	5,101	10,295	3,506
				8,919,522	412,877	925,030	7,560,363	2,349	-	5,101	10,295	3,506
	Oregon Ancillary Services				30,913,774				(30,913,774)			
456	Other Electric Revenue											
		OTHSG	S	125,601	18,780	106,821	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-
		OTHSE	SE	7,359,422	-	7,359,422	-	-	-	-	-	-
		OTHSO	SO	4,085	-	-	4,085	-	-	-	-	-
		OTHSG	SG	50,479,278	7,547,554	42,931,723	-	-	-	-	-	-
				57,968,385	7,566,334	50,397,967	4,085	-	-	-	-	-
	Total Other Electric Revenues			74,085,068	38,902,144	51,328,627	7,569,887	2,392	(30,913,774)	6,875,017	139,049	181,727
	Total Electric Operating Revenues			1,921,396,720	960,442,645	364,269,510	544,224,076	3,513,627	-	12,692,406	20,594,790	15,659,667
41160	Gain on Sale of Utility Plant - CR											
		D	S	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		G	SO	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
41170	Loss on Sale of Utility Plant											
		D_SPLIT-TC	S	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
4118	Gain from Emission Allowances											
		P	S	-	-	-	-	-	-	-	-	-
		P	SE	(11)	(11)	-	-	-	-	-	-	-
				(11)	(11)	-	-	-	-	-	-	-
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	246,124	-	-	246,124	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG-P	5,916	-	5,916	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-
		PTD-TC	SO	(301,810)	(120,395)	(95,119)	(86,296)	-	-	-	-	-
		P	SG	(54,936)	(54,936)	-	-	-	-	-	-	-
				(104,705)	(175,331)	(89,203)	159,829	-	-	-	-	-
	Total Miscellaneous Revenues			(104,716)	(175,342)	(89,203)	159,829	-	-	-	-	-
4311	Interest on Customer Deposits											
		C_BILLING	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Miscellaneous Expenses			-	-	-	-	-	-	-	-	-
	Net Misc Revenue and Expense			(104,716)	(175,342)	(89,203)	159,829	-	-	-	-	-
500	Operation Supervision & Engineering											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	4,941,462	4,941,462	-	-	-	-	-	-	-
				4,941,462	4,941,462	-	-	-	-	-	-	-
501	Fuel Related-Non NPC											
		P	S	-	-	-	-	-	-	-	-	-
		P	SE	916,330	916,330	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
				916,330	916,330	-	-	-	-	-	-	-
501NPC	Fuel Related-NPC											
		P	S	174,552,460	174,552,460	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
				174,552,460	174,552,460	-	-	-	-	-	-	-
	Total Fuel Related			175,468,790	175,468,790	-	-	-	-	-	-	-
502	Steam Expenses											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	20,141,828	20,141,828	-	-	-	-	-	-	-
				20,141,828	20,141,828	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
503	Steam From Other Sources-Non-NPC											
		P	SE	188	188	-	-	-	-	-	-	-
				188	188	-	-	-	-	-	-	-
503NPC	Steam From Other Sources-NPC											
		P	SE	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
505	Electric Expenses											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	334,213	334,213	-	-	-	-	-	-	-
				334,213	334,213	-	-	-	-	-	-	-
506	Misc. Steam Expense											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	13,601,204	13,601,204	-	-	-	-	-	-	-
		P	SE	1,411,173	1,411,173	-	-	-	-	-	-	-
				15,012,376	15,012,376	-	-	-	-	-	-	-
507	Rents											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	157,047	157,047	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				157,047	157,047	-	-	-	-	-	-	-
509	Allowances-Non-NPC											
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
509NPC	Allowances-NPC											
		P	S									
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
510	Maint Supervision & Engineering											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	3,673,430	3,673,430	-	-	-	-	-	-	-
				3,673,430	3,673,430	-	-	-	-	-	-	-
511	Maintenance of Structures											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	6,465,050	6,465,050	-	-	-	-	-	-	-
				6,465,050	6,465,050	-	-	-	-	-	-	-
512	Maintenance of Boiler Plant											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	22,257,027	22,257,027	-	-	-	-	-	-	-
				22,257,027	22,257,027	-	-	-	-	-	-	-
513	Maintenance of Electric Plant											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	11,482,082	11,482,082	-	-	-	-	-	-	-
				11,482,082	11,482,082	-	-	-	-	-	-	-
514	Maintenance of Misc. Steam Plant											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	4,414,681	4,414,681	-	-	-	-	-	-	-
				4,414,681	4,414,681	-	-	-	-	-	-	-
	Total Steam Power Generation			264,348,177	264,348,177	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
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	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
524	Misc. Nuclear Expenses											
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
528	Maintenance Super & Engineering											
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
529	Maintenance of Structures											
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
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	2,755,407	2,755,407	-	-	-	-	-	-	-
		P	SG	1,090,103	1,090,103	-	-	-	-	-	-	-
		P	SG	(447,324)	(447,324)	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				3,398,185	3,398,185	-	-	-	-	-	-	-
536	Water For Power											
		P	DGP	-	-	-	-	-	-	-	-	-
		P	SG	(38,210)	(38,210)	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				(38,210)	(38,210)	-	-	-	-	-	-	-
537	Hydraulic Expenses											
		P	SG	1,555,522	1,555,522	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	109,499	109,499	-	-	-	-	-	-	-
				1,665,020	1,665,020	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
538	Electric Expenses											
		P	DGP	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
539	Misc. Hydro Expenses											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	2,628,934	2,628,934	-	-	-	-	-	-	-
		P	SG	2,790,933	2,790,933	-	-	-	-	-	-	-
				5,419,867	5,419,867	-	-	-	-	-	-	-
540	Rents (Hydro Generation)											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG-P	449,923	449,923	-	-	-	-	-	-	-
		P	SG-U	32,142	32,142	-	-	-	-	-	-	-
				482,065	482,065	-	-	-	-	-	-	-
541	Maint Supervision & Engineering											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG-P	110	110	-	-	-	-	-	-	-
		P	SG-U	-	-	-	-	-	-	-	-	-
				110	110	-	-	-	-	-	-	-
542	Maintenance of Structures											
		P	SG	14,226	14,226	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	138,776	138,776	-	-	-	-	-	-	-
				153,002	153,002	-	-	-	-	-	-	-
543	Maintenance of Dams & Waterways											
		P	SG	128,065	128,065	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	184,941	184,941	-	-	-	-	-	-	-
				313,006	313,006	-	-	-	-	-	-	-
544	Maintenance of Electric Plant											
		P	SG	255,117	255,117	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	198,744	198,744	-	-	-	-	-	-	-
				453,861	453,861	-	-	-	-	-	-	-
545	Maintenance of Misc. Hydro Plant											
		P	SG	1,267,684	1,267,684	-	-	-	-	-	-	-
		P	SG	263,491	263,491	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				1,531,175	1,531,175	-	-	-	-	-	-	-
	Total Hydraulic Power Generation			13,378,082	13,378,082	-	-	-	-	-	-	-
558XP	Solar Power Expenses											
		P	S	232,196	232,196	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				232,196	232,196	-	-	-	-	-	-	-
	Total Solar Power Generation			232,196	232,196	-	-	-	-	-	-	-
558WP	Wind Power Expenses											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	10,283,870	10,283,870	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
				10,283,870	10,283,870	-	-	-	-	-	-	-
	Total Wind Power Generation			10,283,870	10,283,870	-	-	-	-	-	-	-
559NPC	Other Renewable Expenses											
		P	S	1,565,734	1,565,734	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
				1,565,734	1,565,734	-	-	-	-	-	-	-
559	Other Renewable Expenses											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	432,169	432,169	-	-	-	-	-	-	-
				432,169	432,169	-	-	-	-	-	-	-
	Total Other Renewable Power Generation			1,997,903	1,997,903	-	-	-	-	-	-	-
546	Operation Super & Engineering											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	133,665	133,665	-	-	-	-	-	-	-
				133,665	133,665	-	-	-	-	-	-	-
547	Fuel-Non-NPC											
		P	SE	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
547NPC	Fuel-NPC											
		P	S	140,545,976	140,545,976	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
				140,545,976	140,545,976	-	-	-	-	-	-	-
548	Generation Expense											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	8,610,790	8,610,790	-	-	-	-	-	-	-
				8,610,790	8,610,790	-	-	-	-	-	-	-
549	Miscellaneous Other											
		P	S	21,060	21,060	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	2,286,492	2,286,492	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				2,307,552	2,307,552	-	-	-	-	-	-	-
550	Rents											
		P	S	193,512	193,512	-	-	-	-	-	-	-
		P	SG	1,043,269	1,043,269	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				1,236,782	1,236,782	-	-	-	-	-	-	-
551	Maint Supervision & Engineering											
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
552	Maintenance of Structures											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	843,961	843,961	-	-	-	-	-	-	-
				843,961	843,961	-	-	-	-	-	-	-
553	Maint of Generation & Electric Plant											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	5,755,688	5,755,688	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
				5,755,688	5,755,688	-	-	-	-	-	-	-
554	Maintenance of Misc. Other											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	1,716,725	1,716,725	-	-	-	-	-	-	-
				1,716,725	1,716,725	-	-	-	-	-	-	-
	Total Other Power Generation			161,151,138	161,151,138	-	-	-	-	-	-	-
555	Purchased Power-Non NPC											
		P	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
555NPC	Purchased Power-NPC											
		P	S	283,900,565	283,900,565	-	-	-	-	-	-	-
		P	SE	(0)	(0)	-	-	-	-	-	-	-
	Seasonal Contracts	P	SG	-	-	-	-	-	-	-	-	-
		P	DGP	-	-	-	-	-	-	-	-	-
				283,900,565	283,900,565	-	-	-	-	-	-	-
	Total Purchased Power			283,900,565	283,900,565	-	-	-	-	-	-	-
556	System Control & Load Dispatch											
		P	SG	964,030	964,030	-	-	-	-	-	-	-
				964,030	964,030	-	-	-	-	-	-	-
557	Other Expenses											
		P	S	73,841	73,841	-	-	-	-	-	-	-
		P	SG	14,299,676	14,299,676	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-
		P	SE	2,376	2,376	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-
				14,375,893	14,375,893	-	-	-	-	-	-	-
2020 Protocol Adjustment												
Baseline ECD		P	S	(11,000,000)	(11,000,000)	-	-	-	-	-	-	-
WY QF Adjustment		P	S	-	-	-	-	-	-	-	-	-
				(11,000,000)	(11,000,000)	-	-	-	-	-	-	-
	Total Other Power Supply			288,240,488	288,240,488	-	-	-	-	-	-	-
	Total Production Expense			739,631,854	739,631,854	-	-	-	-	-	-	-
560	Operation Supervision & Engineering											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	4,091,529	-	4,091,529	-	-	-	-	-	-
				4,091,529	-	4,091,529	-	-	-	-	-	-
561	Load Dispatching											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	6,298,885	-	6,298,885	-	-	-	-	-	-
				6,298,885	-	6,298,885	-	-	-	-	-	-
562	Station Expense											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	1,050,420	-	1,050,420	-	-	-	-	-	-
				1,050,420	-	1,050,420	-	-	-	-	-	-
563	Overhead Line Expense											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	502,670	-	502,670	-	-	-	-	-	-
				502,670	-	502,670	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
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	S	66,612,911	-	66,612,911	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		T	SE	-	-	-	-	-	-	-	-	-
				66,612,911	-	66,612,911	-	-	-	-	-	-
	Total Transmission of Electricity by Others			66,612,911	-	66,612,911	-	-	-	-	-	-
566	Misc. Transmission Expense											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	1,232,439	-	1,232,439	-	-	-	-	-	-
				1,232,439	-	1,232,439	-	-	-	-	-	-
567	Rents - Transmission											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	690,527	-	690,527	-	-	-	-	-	-
				690,527	-	690,527	-	-	-	-	-	-
568	Maint Supervision & Engineering											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	510,375	-	510,375	-	-	-	-	-	-
				510,375	-	510,375	-	-	-	-	-	-
569	Maintenance of Structures											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	2,169,056	-	2,169,056	-	-	-	-	-	-
				2,169,056	-	2,169,056	-	-	-	-	-	-
570	Maintenance of Station Equipment											
		STEP_UP	SG	-	-	-	-	-	-	-	-	-
		STEP_UP	SG	4,054,873	231,002	3,823,871	-	-	-	-	-	-
				4,054,873	231,002	3,823,871	-	-	-	-	-	-
571	Maintenance of Overhead Lines											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	3,967,664	-	3,967,664	-	-	-	-	-	-
				3,967,664	-	3,967,664	-	-	-	-	-	-
572	Maintenance of Underground Lines											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	34,276	-	34,276	-	-	-	-	-	-
				34,276	-	34,276	-	-	-	-	-	-
573	Maint of Misc. Transmission Plant											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	91,487	-	91,487	-	-	-	-	-	-
				91,487	-	91,487	-	-	-	-	-	-
	Total Transmission Expense			91,307,111	231,002	91,076,110	-	-	-	-	-	-
580	Operation Supervision & Engineering											
		D_SPLIT-TC	S	5,491,556	-	-	5,277,125	40,719	-	-	173,713	-
		D_SPLIT-TC	SNPD	1,991,660	-	-	1,913,890	14,768	-	-	63,001	-
				7,483,215	-	-	7,191,015	55,486	-	-	236,714	-
581	Load Dispatching											
		D	S	-	-	-	-	-	-	-	-	-
		D	SNPD	4,661,312	-	-	4,661,312	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
				4,661,312	-	-	4,661,312	-	-	-	-	-
582	Station Expense											
		D	S	1,316,622	-	-	1,316,622	-	-	-	-	-
		D	SNPD	127	-	-	127	-	-	-	-	-
				1,316,749	-	-	1,316,749	-	-	-	-	-
583	Overhead Line Expenses											
		D	S	1,545,622	-	-	1,545,622	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-
				1,545,622	-	-	1,545,622	-	-	-	-	-
584	Underground Line Expense											
		D	S	-	-	-	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
585	Street Lighting & Signal Systems											
		DL	S	-	-	-	-	-	-	-	-	-
		DL	SNPD	82,529	-	-	-	82,529	-	-	-	-
				82,529	-	-	-	82,529	-	-	-	-
586	Meter Expenses											
		C_METER	S	1,594,087	-	-	-	-	-	-	1,594,087	-
		C_METER	SNPD	2,798	-	-	-	-	-	-	2,798	-
				1,596,884	-	-	-	-	-	-	1,596,884	-
587	Customer Installation Expenses											
		D	S	7,502,020	-	-	7,502,020	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-
				7,502,020	-	-	7,502,020	-	-	-	-	-
588	Misc. Distribution Expenses											
		D	S	(816,416)	-	-	(816,416)	-	-	-	-	-
		D	SNPD	(363,026)	-	-	(363,026)	-	-	-	-	-
				(1,179,442)	-	-	(1,179,442)	-	-	-	-	-
589	Rents											
		D	S	1,929,572	-	-	1,929,572	-	-	-	-	-
		D	SNPD	152,985	-	-	152,985	-	-	-	-	-
				2,082,557	-	-	2,082,557	-	-	-	-	-
590	Maint Supervision & Engineering											
		D_SPLIT-TC	S	1,529,238	-	-	1,469,525	11,339	-	-	48,374	-
		D_SPLIT-TC	SNPD	1,110,600	-	-	1,067,234	8,235	-	-	35,131	-
				2,639,838	-	-	2,536,759	19,574	-	-	83,505	-
591	Maintenance of Structures											
		D	S	1,466,942	-	-	1,466,942	-	-	-	-	-
		D	SNPD	35,069	-	-	35,069	-	-	-	-	-
				1,502,011	-	-	1,502,011	-	-	-	-	-
592	Maintenance of Station Equipment											
		D	S	5,335,515	-	-	5,335,515	-	-	-	-	-
		D	SNPD	882,891	-	-	882,891	-	-	-	-	-
				6,218,406	-	-	6,218,406	-	-	-	-	-
593	Maintenance of Overhead Lines											
		D	S	74,287,728	-	-	74,287,728	-	-	-	-	-
		D	SNPD	1,000,106	-	-	1,000,106	-	-	-	-	-
				75,287,834	-	-	75,287,834	-	-	-	-	-
594	Maintenance of Underground Lines											
		D	S	11,445,031	-	-	11,445,031	-	-	-	-	-
		D	SNPD	2,076	-	-	2,076	-	-	-	-	-
				11,447,107	-	-	11,447,107	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
595	Maintenance of Line Transformers											
		D	S	-	-	-	-	-	-	-	-	-
		D	SNPD	281,954	-	-	281,954	-	-	-	-	-
				281,954	-	-	281,954	-	-	-	-	-
596	Maint of Street Lighting & Signal Sys.											
		DL	S	867,844	-	-	-	867,844	-	-	-	-
		DL	SNPD	-	-	-	-	-	-	-	-	-
				867,844	-	-	-	867,844	-	-	-	-
597	Maintenance of Meters											
		C_METER	S	228,077	-	-	-	-	-	-	228,077	-
		C_METER	SNPD	(40,595)	-	-	-	-	-	-	(40,595)	-
				187,482	-	-	-	-	-	-	187,482	-
598	Maint of Misc. Distribution Plant											
		D	S	1,083,990	-	-	1,083,990	-	-	-	-	-
		D	SNPD	1,168,749	-	-	1,168,749	-	-	-	-	-
				2,252,739	-	-	2,252,739	-	-	-	-	-
	Total Distribution Expense			125,776,662	-	-	122,646,644	1,025,433	-	-	2,104,585	-
901	Supervision											
		CUST901	S	-	-	-	-	-	-	-	-	-
		CUST901	CN	6,719,767	-	-	-	-	-	2,748,866	1,195,774	2,775,128
				6,719,767	-	-	-	-	-	2,748,866	1,195,774	2,775,128
902	Meter Reading Expense											
		C_METER	S	2,151,766	-	-	-	-	-	-	2,151,766	-
		C_METER	CN	401,886	-	-	-	-	-	-	401,886	-
				2,553,652	-	-	-	-	-	-	2,553,652	-
903	Customer Receipts & Collections											
		CUST903	S	2,270,062	-	-	-	-	-	993,759	273,049	1,003,253
		CUST903	CN	9,415,973	-	-	-	-	-	4,122,007	1,132,578	4,161,387
				11,686,034	-	-	-	-	-	5,115,766	1,405,627	5,164,640
904	Uncollectible Accounts											
		REVREQ-TC	S	11,174,954	6,932,883	1,555,747	2,402,107	15,430	-	74,046	103,667	91,073
		P	SG	-	-	-	-	-	-	-	-	-
		REVREQ-TC	CN	(2,532)	(1,571)	(352)	(544)	(3)	-	(17)	(23)	(21)
				11,172,422	6,931,313	1,555,395	2,401,563	15,426	-	74,029	103,644	91,052
905	Misc. Customer Accounts Expense											
		CUST905	S	0	-	-	-	-	-	-	-	0
		CUST905	CN	-	-	-	-	-	-	-	-	-
				0	-	-	-	-	-	-	-	0
	Total Customer Accounts Expense			32,131,875	6,931,313	1,555,395	2,401,563	15,426	-	7,938,662	5,258,697	8,030,820
907	Supervision											
		C_SERVICE	S	-	-	-	-	-	-	-	-	-
		C_SERVICE	CN	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
908	Customer Assistance											
		DSM	S	2,328,091	-	-	2,328,091	-	-	-	-	-
		C_SERVICE	CN	1,276,817	-	-	-	-	-	-	-	1,276,817
				3,604,908	-	-	2,328,091	-	-	-	-	1,276,817
909	Informational & Instructional Adv											
		C_SERVICE	S	662,140	-	-	-	-	-	-	-	662,140
		C_SERVICE	CN	1,008,093	-	-	-	-	-	-	-	1,008,093
				1,670,232	-	-	-	-	-	-	-	1,670,232
910	Misc. Customer Service											
		C_SERVICE	S	-	-	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
		C_SERVICE	CN	48,927	-	-	-	-	-	-	-	48,927
				48,927	-	-	-	-	-	-	-	48,927
	Total Customer Service Expense			5,324,067	-	-	2,328,091	-	-	-	-	2,995,976
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			-	-	-	-	-	-	-	-	-
920	Administrative & General Salaries											
		LABOR	S	(2,494)	(916)	(199)	(1,117)	(12)	-	(73)	(75)	(102)
		LABOR	CN	-	-	-	-	-	-	-	-	-
		LABOR	SO	26,048,105	9,563,134	2,077,901	11,669,084	128,956	-	761,970	780,720	1,066,340
				26,045,611	9,562,218	2,077,702	11,667,967	128,944	-	761,897	780,645	1,066,237
921	Office Supplies & expenses											
		LABOR	S	(134,135)	(49,246)	(10,700)	(60,090)	(664)	-	(3,924)	(4,020)	(5,491)
		LABOR	CN	37,195	13,656	2,967	16,663	184	-	1,088	1,115	1,523
		LABOR	SO	5,940,291	2,180,880	473,867	2,661,144	29,409	-	173,768	178,044	243,180
				5,843,351	2,145,290	466,134	2,617,716	28,929	-	170,932	175,138	239,211
922	A&G Expenses Transferred											
		LABOR	S	-	-	-	-	-	-	-	-	-
		LABOR	CN	-	-	-	-	-	-	-	-	-
		LABOR	SO	(13,470,200)	(4,945,362)	(1,074,540)	(6,034,408)	(66,687)	-	(394,036)	(403,732)	(551,434)
				(13,470,200)	(4,945,362)	(1,074,540)	(6,034,408)	(66,687)	-	(394,036)	(403,732)	(551,434)
923	Outside Services											
		LABOR	S	77,189	28,339	6,158	34,579	382	-	2,258	2,314	3,160
		LABOR	CN	-	-	-	-	-	-	-	-	-
		LABOR	SO	13,966,201	5,127,461	1,114,107	6,256,608	69,142	-	408,545	418,598	571,739
				14,043,390	5,155,800	1,120,265	6,291,187	69,525	-	410,803	420,912	574,899
924	Property Insurance											
		DPW	S	44,234,652	-	-	42,835,392	-	-	-	1,399,260	-
		PT-TC	SG	-	-	-	-	-	-	-	-	-
		GP-TC	SO	1,540,442	610,586	456,968	441,461	3,474	-	7,543	15,224	5,185
				45,775,094	610,586	456,968	43,276,853	3,474	-	7,543	1,414,484	5,185
925	Injuries & Damages											
		DPW	S	26,193,033	-	-	25,364,478	-	-	-	828,555	-
		LABOR	SO	15,326,206	5,626,765	1,222,597	6,865,865	75,875	-	448,329	459,361	627,414
				41,519,239	5,626,765	1,222,597	32,230,344	75,875	-	448,329	1,287,916	627,414
926	Employee Pensions & Benefits											
		LABOR	S	536,407	196,933	42,790	240,301	2,656	-	15,691	16,077	21,959
		LABOR	SG	-	-	-	-	-	-	-	-	-
		LABOR	SO	41,018,992	15,059,449	3,272,154	18,375,773	203,073	-	1,199,905	1,229,431	1,679,208
				41,555,399	15,256,382	3,314,944	18,616,073	205,728	-	1,215,596	1,245,508	1,701,167

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
927	Franchise Requirements											
		DSM	S	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
928	Regulatory Commission Expense											
		D	S	12,221,673	-	-	12,221,673	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		D	SO	783,557	-	-	783,557	-	-	-	-	-
		FERC	SG	1,352,035	452,967	899,068	-	-	-	-	-	-
				14,357,265	452,967	899,068	13,005,231	-	-	-	-	-
929	Duplicate Charges											
		LABOR	S	-	-	-	-	-	-	-	-	-
		LABOR	SO	(46,082,924)	(16,918,588)	(3,676,112)	(20,644,324)	(228,143)	-	(1,348,037)	(1,381,208)	(1,886,511)
				(46,082,924)	(16,918,588)	(3,676,112)	(20,644,324)	(228,143)	-	(1,348,037)	(1,381,208)	(1,886,511)
930	Misc General Expenses											
		LABOR	S	(298,614)	(109,631)	(23,821)	(133,774)	(1,478)	-	(8,735)	(8,950)	(12,224)
		C_SERVICE	CN	-	-	-	-	-	-	-	-	-
		P	SG	(457,726)	(457,726)	-	-	-	-	-	-	-
		LABOR	SO	417,593	153,312	33,312	187,074	2,067	-	12,216	12,516	17,095
				(338,747)	(414,045)	9,491	53,301	589	-	3,480	3,566	4,871
931	Rents											
		LABOR	S	83,392	30,616	6,652	37,358	413	-	2,439	2,499	3,414
		LABOR	SO	182,971	67,175	14,596	81,968	906	-	5,352	5,484	7,490
				266,364	97,791	21,248	119,326	1,319	-	7,792	7,984	10,904
935	Maintenance of General Plant											
		G	S	365,103	78,364	109,115	147,225	-	-	12,431	8,903	9,066
		B_Center	CN	26,083	-	-	-	-	-	16,992	-	9,091
		G	SO	10,981,047	2,356,920	3,281,804	4,428,018	-	-	373,867	267,768	272,670
				11,372,233	2,435,284	3,390,920	4,575,242	-	-	403,289	276,671	290,827
	Total Administrative & General Expense			140,886,076	19,065,087	8,228,684	105,774,509	219,553	-	1,687,589	3,827,884	2,082,770
	Total O&M Expense			1,135,057,645	765,859,255	100,860,189	233,150,806	1,260,412	-	9,626,250	11,191,166	13,109,566
403SP	Steam Depreciation											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	87,374,141	87,374,141	-	-	-	-	-	-	-
				87,374,141	87,374,141	-	-	-	-	-	-	-
403NP	Nuclear Depreciation											
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
403HP	Hydro Depreciation											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	8,729,471	8,729,471	-	-	-	-	-	-	-
		P	SG	3,001,156	3,001,156	-	-	-	-	-	-	-
		P	SG	1,155,473	1,155,473	-	-	-	-	-	-	-
				12,886,101	12,886,101	-	-	-	-	-	-	-
403OP	Other Production Depreciation											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	20,955,232	20,955,232	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				20,955,232	20,955,232	-	-	-	-	-	-	-
403RP	Other Renewable Depreciation											

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	839,214	839,214	-	-	-	-	-	-	-
				839,214	839,214	-	-	-	-	-	-	-
403XP	Solar Depreciation											
		P	S	126,881	126,881	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				126,881	126,881	-	-	-	-	-	-	-
403WP	Wind Depreciation											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	52,619,366	52,619,366	-	-	-	-	-	-	-
				52,619,366	52,619,366	-	-	-	-	-	-	-
403TP	Transmission Depreciation											
		T_Split-TC	S	(0)	(0)	(0)	-	-	-	-	-	-
		T_Split-TC	SG	-	-	-	-	-	-	-	-	-
		T_Split-TC	SG	-	-	-	-	-	-	-	-	-
		T_Split-TC	SG	60,455,495	902,367	59,553,128	-	-	-	-	-	-
				60,455,495	902,367	59,553,128	-	-	-	-	-	-
403	Distribution Depreciation											
360	Land & Land Rights	D	S	157,551	-	-	157,551	-	-	-	-	-
361	Structures	D	S	760,804	-	-	760,804	-	-	-	-	-
362	Station Equipment	D	S	10,314,403	-	-	10,314,403	-	-	-	-	-
362	Station Equipment	D	SG	-	-	-	-	-	-	-	-	-
363	Storage Battery Equipment	D	S	1,507,218	-	-	1,507,218	-	-	-	-	-
363	Storage Battery Equipment	D	SNPD	277,916	-	-	277,916	-	-	-	-	-
363	Storage Battery Equipment	D	SO	-	-	-	-	-	-	-	-	-
363	Storage Battery Equipment	D	SG	-	-	-	-	-	-	-	-	-
364	Poles & Towers	D	S	20,549,030	-	-	20,549,030	-	-	-	-	-
365	OH Conductors	D	S	9,533,952	-	-	9,533,952	-	-	-	-	-
366	UG Conduit	D	S	2,837,885	-	-	2,837,885	-	-	-	-	-
367	UG Conductor	D	S	6,290,403	-	-	6,290,403	-	-	-	-	-
368	Line Trans	D	S	14,099,495	-	-	14,099,495	-	-	-	-	-
369	Services	D	S	9,137,572	-	-	9,137,572	-	-	-	-	-
370	Meters	C_METER	S	2,220,557	-	-	-	-	-	-	2,220,557	-
371	Inst Cust Prem	DL	S	127,873	-	-	-	127,873	-	-	-	-
372	Leased Property	D	S	-	-	-	-	-	-	-	-	-
373	Street Lighting	DL	S	699,721	-	-	-	699,721	-	-	-	-
				78,514,380	-	-	75,466,229	827,593	-	-	2,220,557	-
403GP	General Depreciation											
		TD-TC	S	2,146,608	-	1,125,501	1,021,106	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-
		P	SE	25,658	25,658	-	-	-	-	-	-	-
		B_Center	CN	2,101,488	-	-	-	-	-	1,369,005	-	732,482
		G-SG	SG	750,437	393,366	357,071	-	-	-	-	-	-
		LABOR	SO	18,999,577	6,975,383	1,515,628	8,511,470	94,061	-	555,784	569,460	777,792
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				24,023,768	7,394,407	2,998,201	9,532,576	94,061	-	1,924,789	569,460	1,510,274
403GV0	General Vehicles											
		G-SG	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
403MP	Mining Depreciation											
		P	SE	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
403EP	Experimental Plant Depreciation											
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
4031	ARO Depreciation											

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
		P	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Depreciation Expense			337,794,580	183,097,711	62,551,329	84,998,805	921,655	-	1,924,789	2,790,017	1,510,274
404GP	Amort of LT Plant - Leasehold Improvements											
		TD-TC	S	75,382	-	39,524	35,858	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-
		LABOR	SO	9,539	3,502	761	4,273	47	-	279	286	391
		I-DGU	SG	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-
				84,921	3,502	40,285	40,131	47	-	279	286	391
404SP	Amort of LT Plant - Cap Lease Steam											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
404IP	Amort of LT Plant - Intangible Plant											
		TD-TC	S	8,838	-	4,634	4,204	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		I-SG	SG	1,526,824	1,001,416	525,408	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-
		I-SG	SG	744,675	488,419	256,256	-	-	-	-	-	-
		I-SG	SG	70,929	46,521	24,408	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-
		I-DGU	SG	-	-	-	-	-	-	-	-	-
				2,351,266	1,536,356	810,706	4,204	-	-	-	-	-
404MP	Amort of LT Plant - Mining Plant											
		P	SE	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
404OP	Amort of LT Plant - Other Plant											
		P	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
404XP	Amort of LT Solar Plant											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
404WP	Amort of LT Plant - Wind Plant											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
404RP	Amort of LT Plant - Other Renewable Plant											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
404HP	Amortization of Other Electric Plant											
		P	SG	87,356	87,356	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				87,356	87,356	-	-	-	-	-	-	-
	Total Amortization of Limited Term Plant			2,523,544	1,627,214	850,991	44,335	47	-	279	286	391
405	Amortization of Other Electric Plant											
		GP-TC	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account											
FERC		**Functional**									
406	Amortization of Plant Acquisition Adj										
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	20,914	20,914	-	-	-	-	-	-	-
		P	SO	-	-	-	-	-	-	-	-	-
				20,914	20,914	-	-	-	-	-	-	-
407	Amort of Prop Losses, Unrec Plant, etc											
		DPW	S	(6,805,180)	-	-	(6,589,914)	-	-	-	(215,266)	-
		GP-TC	SO	-	-	-	-	-	-	-	-	-
		P	SG-P	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		P	SG	3,965,515	3,965,515	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-
				(2,839,665)	3,965,515	-	(6,589,914)	-	-	-	(215,266)	-
	Total Amortization Expense			(295,207)	5,613,643	850,991	(6,545,578)	47	-	279	(214,980)	391
408	Taxes Other Than Income											
		D	S	53,275,467	-	-	53,275,467	-	-	-	-	-
		GP-TC	GPS	51,698,451	20,491,738	15,336,211	14,815,790	116,599	-	253,150	510,937	174,027
		REVREQ-TC	SO	6,146,858	3,813,479	855,749	1,321,295	8,487	-	40,730	57,023	50,095
		P	SE	311,053	311,053	-	-	-	-	-	-	-
		P	SG	1,450,106	1,450,106	-	-	-	-	-	-	-
		DSM	OPRV-ID	-	-	-	-	-	-	-	-	-
		GP-TC	EXCTAX	-	-	-	-	-	-	-	-	-
		GP-TC	SG	-	-	-	-	-	-	-	-	-
				112,881,934	26,066,375	16,191,960	69,412,552	125,086	-	293,880	567,960	224,122
41140	Deferred Investment Tax Credit - Fed											
		PTD-TC	DGU	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
41141	Deferred Investment Tax Credit - Idaho											
		PTD-TC	DGU	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Deferred ITC			-	-	-	-	-	-	-	-	-
427	Interest on Long-Term Debt											
		NP-TC	S	178,098,945	63,244,574	62,090,099	50,370,674	293,753	-	263,085	1,584,241	252,519
		NP-TC	SNP	-	-	-	-	-	-	-	-	-
				178,098,945	63,244,574	62,090,099	50,370,674	293,753	-	263,085	1,584,241	252,519
428	Amortization of Debt Disc & Exp											
		NP-TC	SNP	1,998,446	709,667	696,712	565,209	3,296	-	2,952	17,777	2,834
				1,998,446	709,667	696,712	565,209	3,296	-	2,952	17,777	2,834
429	Amortization of Premium on Debt											
		NP-TC	SNP	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
431	Other Interest Expense											
		NUTIL	OTH	-	-	-	-	-	-	-	-	-
		GP-TC	SO	-	-	-	-	-	-	-	-	-
		NP-TC	SNP	12,946,080	4,597,272	4,513,353	3,661,463	21,353	-	19,124	115,159	18,356
				12,946,080	4,597,272	4,513,353	3,661,463	21,353	-	19,124	115,159	18,356
432	AFUDC - Borrowed											
		NP-TC	SNP	(28,422,473)	(10,093,082)	(9,908,841)	(8,038,560)	(46,879)	-	(41,985)	(252,826)	(40,299)
				(28,422,473)	(10,093,082)	(9,908,841)	(8,038,560)	(46,879)	-	(41,985)	(252,826)	(40,299)
	Total Interest Deductions for Tax			164,620,998	58,458,431	57,391,323	46,558,786	271,522	-	243,176	1,464,351	233,409
419	Interest & Dividends											

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
		GP-TC	S	-	-	-	-	-	-	-	-	-
		GP-TC	SNP	(2,826,222)	(1,120,231)	(838,391)	(809,941)	(6,374)	-	(13,839)	(27,932)	(9,514)
				(2,826,222)	(1,120,231)	(838,391)	(809,941)	(6,374)	-	(13,839)	(27,932)	(9,514)
	Total Operating Deductions for Tax			(2,826,222)	(1,120,231)	(838,391)	(809,941)	(6,374)	-	(13,839)	(27,932)	(9,514)
41010	Deferred Income Tax - Federal-DR											
		GP-TC	S	(3,210,509)	(1,272,551)	(952,389)	(920,071)	(7,241)	-	(15,721)	(31,730)	(10,807)
		P	TROJD	-	-	-	-	-	-	-	-	-
		PT-TC	SG	-	-	-	-	-	-	-	-	-
		LABOR	SO	(1,838,243)	(674,881)	(146,640)	(823,500)	(9,101)	-	(53,773)	(55,096)	(75,253)
		NP-TC	SNP	1,007,835	357,891	351,358	285,040	1,662	-	1,489	8,965	1,429
		P	SE	-	-	-	-	-	-	-	-	-
		PT-TC	SG	2,326,465	1,299,663	1,026,803	-	-	-	-	-	-
		GP-TC	GPS	1,172,502	464,745	347,820	336,017	2,644	-	5,741	11,588	3,947
		TAXDEPR	DITEXP	-	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-
		IBT-TC	IBT	-	-	-	-	-	-	-	-	-
		D	CIAC	-	-	-	-	-	-	-	-	-
		P	SCHMDEXP	-	-	-	-	-	-	-	-	-
		TAXDEPR	TAXDEPR	98,919,335	32,289,880	35,546,538	30,904,872	19,683	-	42,734	86,251	29,378
		D	SNPD	(0)	-	-	(0)	-	-	-	-	-
				98,377,386	32,464,747	36,173,489	29,782,358	7,648	-	(19,529)	19,979	(51,307)
41110	Deferred Income Tax - Federal-CR											
		GP-TC	S	(6,989,069)	(2,770,260)	(2,073,289)	(2,002,934)	(15,763)	-	(34,223)	(69,073)	(23,527)
		P	SE	1,044,101	1,044,101	-	-	-	-	-	-	-
		PT-TC	SG	-	-	-	-	-	-	-	-	-
		NP-TC	SNP	(727,207)	(258,238)	(253,524)	(205,672)	(1,199)	-	(1,074)	(6,469)	(1,031)
		PT-TC	SG	820,913	458,597	362,316	-	-	-	-	-	-
		GP-TC	GPS	-	-	-	-	-	-	-	-	-
		LABOR	SO	962,176	353,247	76,754	431,037	4,763	-	28,146	28,839	39,389
		D	SNPD	-	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	0	-	-	-	-	-	0	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-
		TAXDEPR	DITEXP	-	-	-	-	-	-	-	-	-
		P	TROJD	(2,511)	(2,511)	-	-	-	-	-	-	-
		IBT-TC	IBT	-	-	-	-	-	-	-	-	-
		D_SPLIT-TC	CIAC	(2,375,590)	-	-	(2,282,829)	(17,614)	-	-	(75,146)	-
		BOOKDEPR	SCHMDEXP	(82,082,837)	(49,629,741)	(13,693,390)	(17,687,156)	(196,939)	-	(146,674)	(621,963)	(106,973)
		TAXDEPR	TAXDEPR	-	-	-	-	-	-	-	-	-
				(89,350,025)	(50,804,807)	(15,581,133)	(21,747,554)	(226,753)	-	(153,825)	(743,812)	(92,141)
	Total Deferred Income Taxes			9,027,360	(18,340,059)	20,592,356	8,034,804	(219,104)	-	(173,355)	(723,834)	(143,448)
SCHMAF	Additions - Flow Through											
		P	S	-	-	-	-	-	-	-	-	-
		P	SNP	-	-	-	-	-	-	-	-	-
		P	SO	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
SCHMAP	Additions - Permanent											
		P	S	-	-	-	-	-	-	-	-	-
		P	SE	4,753	4,753	-	-	-	-	-	-	-
		PTD-TC	SNP	-	-	-	-	-	-	-	-	-
		SCHMAP-SO	SO	622,055	69,300	69,674	391,274	4,324	-	25,550	26,178	35,755
		SCHMAP	SG	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	36,612	22,137	6,108	7,889	88	-	65	277	48
				663,421	96,190	75,782	399,164	4,412	-	25,615	26,456	35,803
SCHMAT	Additions - Temporary											
		SCHMAT-SITUS	S	(13,389,750)	(3,273,589)	(3,391,695)	(5,925,303)	(37,640)	-	(222,404)	(227,876)	(311,243)
		P	SG	-	-	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
		D_SPLIT-TC	CIAC	9,662,133	-	-	9,284,852	71,643	-	-	305,639	-
		SCHMAT-SNP	SNP	2,957,736	1,179,863	932,088	845,703	9	-	20	40	14
		P	TROJD	10,216	10,216	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		SCHMAT-SE	SE	(4,246,621)	(4,246,498)	(15)	(87)	(1)	-	(6)	(6)	(8)
		P	SG	3,359,114	3,359,114	-	-	-	-	-	-	-
		SCHMAT-SG	GPS	0	0	-	-	-	-	-	-	-
		SCHMAT-SO	SO	(3,105,648)	(969,115)	1,019,472	(2,263,689)	(42,027)	-	(248,328)	(254,438)	(347,523)
		SCHMAT-SNP	SNPD	-	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	0	-	-	-	-	-	0	-	-
		SCHMAT	CN	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	333,851,922	201,856,871	55,694,526	71,938,195	801,002	-	596,561	2,529,682	435,086
				329,099,103	197,916,861	54,254,376	73,879,672	792,986	-	125,843	2,353,040	(223,674)
	Total Schedule - M Additions			329,762,524	198,013,051	54,330,157	74,278,835	797,398	-	151,458	2,379,496	(187,871)
SCHMDF	Deductions - Flow Through											
		P	S	-	-	-	-	-	-	-	-	-
		P	DGP	-	-	-	-	-	-	-	-	-
		P	DGU	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
SCHMDP	Deductions - Permanent											
		SCHMDP	S	-	-	-	-	-	-	-	-	-
		P	SE	1,507,617	1,507,617	-	-	-	-	-	-	-
		SCHMDP	SNP	0	0	0	0	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		PTD-TC	SO	-	-	-	-	-	-	-	-	-
				1,507,617	1,507,617	0	0	-	-	-	-	-
SCHMDT	Deductions - Temporary											
		SCHMDT-SITUS	S	(13,057,961)	(13,929,338)	224,560	614,798	2,279	-	10,578	5,554	13,609
		SCHMDT	BADDEBT	-	-	-	-	-	-	-	-	-
		SCHMDT-SNP	SNP	4,099,120	1,635,184	1,291,882	1,172,055	-	-	-	-	-
		SCHMDT	CN	-	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	-	-	-	-	-	-	-	-	-
		SCHMDT-SG	DGP	-	-	-	-	-	-	-	-	-
		P	SE	(0)	(0)	-	-	-	-	-	-	-
		SCHMDT-SG	SG	9,462,333	9,298,253	164,080	-	-	-	-	-	-
		SCHMDT-GPS	GPS	4,768,865	1,902,352	1,502,959	1,363,554	-	-	-	-	-
		SCHMDT-SO	SO	(7,476,604)	(2,658,491)	(46,070)	(3,754,388)	(48,215)	-	(283,037)	(291,073)	(395,329)
		TAXDEPR	TAXDEPR	402,330,276	131,331,211	144,576,873	125,698,030	80,056	-	173,812	350,807	119,486
		SCHMDT-SNP	SNPD	0	0	0	0	-	-	-	-	-
				400,126,029	127,579,170	147,714,285	125,094,049	34,120	-	(98,648)	65,288	(262,234)
	Total Schedule - M Deductions			401,633,646	129,086,786	147,714,285	125,094,049	34,120	-	(98,648)	65,288	(262,234)
	Total Schedule - M Adjustments			(71,871,122)	68,926,265	(93,384,127)	(50,815,214)	763,278	-	250,106	2,314,208	74,363
40911	State Income Taxes											
		REVREQ-TC		4,648,805	2,884,095	647,194	999,282	6,419	-	30,803	43,126	37,887
		REVREQ-TC	S	492,784	305,721	68,604	105,926	680	-	3,265	4,571	4,016
	Total State Tax Expense			5,141,589	3,189,815	715,798	1,105,208	7,099	-	34,069	47,697	41,903
	Calculation of Taxable Income:											
	Operating Revenues			1,921,396,720	960,442,645	364,269,510	544,224,076	3,513,627	-	12,692,406	20,594,790	15,659,667
	Operating Deductions:											
	O & M Expenses			1,135,057,645	765,859,255	100,860,189	233,150,806	1,260,412	-	9,626,250	11,191,166	13,109,566
	Depreciation Expense			337,794,580	183,097,711	62,551,329	84,998,805	921,655	-	1,924,789	2,790,017	1,510,274
	Amortization Expense			(295,207)	5,613,643	850,991	(6,545,578)	47	-	279	(214,980)	391
	Taxes Other Than Income			112,881,934	26,066,375	16,191,960	69,412,552	125,086	-	293,880	567,960	224,122
	Interest & Dividends (AFUDC-Equity)			(2,826,222)	(1,120,231)	(838,391)	(809,941)	(6,374)	-	(13,839)	(27,932)	(9,514)
	Misc Revenue & Expense			(104,716)	(175,342)	(89,203)	159,829	-	-	-	-	-
	Total Operating Deductions			1,582,508,013	979,341,410	179,526,874	380,366,472	2,300,826	-	11,831,359	14,306,231	14,834,839
	Other Deductions:											
	Interest Deductions			164,620,998	58,458,431	57,391,323	46,558,786	271,522	-	243,176	1,464,351	233,409

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
	Interest on PCRBS			-	-	-	-	-	-	-	-	-
	Schedule M Adjustments			(71,871,122)	68,926,265	(93,384,127)	(50,815,214)	763,278	-	250,106	2,314,208	74,363
	Income Before State Taxes			102,396,587	(8,430,931)	33,967,185	66,483,604	1,704,556	-	867,976	7,138,416	665,781
	State Income Taxes			5,141,589	3,189,815	715,798	1,105,208	7,099	-	34,069	47,697	41,903
	Total Taxable Income			97,254,998	(11,620,747)	33,251,387	65,378,396	1,697,456	-	833,908	7,090,718	623,879
Tax Rate				0	21%	21%	21%	21%	21%	21%	21%	21%
	Federal Income Tax - Calculated			20,423,550	(2,440,357)	6,982,791	13,729,463	356,466	-	175,121	1,489,051	131,015
	Adjustments to Calculated Tax:											
40910		P	SE	(3,705)	(3,705)	-	-	-	-	-	-	-
40910	PTC	P	SG	0	0	-	-	-	-	-	-	-
40910		P	SO	(15,423)	(15,423)	-	-	-	-	-	-	-
40910	PTC	P	S	(81,033,112)	(81,033,112)	-	-	-	-	-	-	-
	Federal Income Tax Expense			(60,628,691)	(83,492,597)	6,982,791	13,729,463	356,466	-	175,121	1,489,051	131,015
	Total Operating Expenses			1,538,874,495	881,818,801	208,656,212	404,045,889	2,451,661	-	11,881,033	15,147,077	14,873,822
310	Land and Land Rights											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	14,021,653	14,021,653	-	-	-	-	-	-	-
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				14,021,653	14,021,653	-	-	-	-	-	-	-
311	Structures and Improvements											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	291,182,482	291,182,482	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				291,182,482	291,182,482	-	-	-	-	-	-	-
312	Boiler Plant Equipment											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	1,230,177,591	1,230,177,591	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				1,230,177,591	1,230,177,591	-	-	-	-	-	-	-
314	Turbogenerator Units											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	267,976,251	267,976,251	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				267,976,251	267,976,251	-	-	-	-	-	-	-
315	Accessory Electric Equipment											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	122,444,352	122,444,352	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				122,444,352	122,444,352	-	-	-	-	-	-	-
316	Misc Power Plant Equipment											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	9,136,138	9,136,138	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				9,136,138	9,136,138	-	-	-	-	-	-	-
317	Steam Plant ARO											
		P	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
SP	Unclassified Steam Plant - Account 300											

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
		P	SG	48,854,140	48,854,140	-	-	-	-	-	-	-
				48,854,140	48,854,140	-	-	-	-	-	-	-
	Total Steam Plant			1,983,792,608	1,983,792,608	-	-	-	-	-	-	-
320	Land and Land Rights											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
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 Plant			-	-	-	-	-	-	-	-	-
330	Land and Land Rights											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	8,580,084	8,580,084	-	-	-	-	-	-	-
		P	SG	1,831,400	1,831,400	-	-	-	-	-	-	-
				10,411,484	10,411,484	-	-	-	-	-	-	-
331	Structures and Improvements											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	83,746,396	83,746,396	-	-	-	-	-	-	-
		P	SG	6,463,197	6,463,197	-	-	-	-	-	-	-
				90,209,593	90,209,593	-	-	-	-	-	-	-
332	Reservoirs, Dams & Waterways											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	157,929,948	157,929,948	-	-	-	-	-	-	-
		P	SG	40,179,174	40,179,174	-	-	-	-	-	-	-
		P	SG	(277,687)	(277,687)	-	-	-	-	-	-	-
				197,831,434	197,831,434	-	-	-	-	-	-	-
333	Water Wheel, Turbines, & Generators											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	22,522,553	22,522,553	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
		P	SG	14,234,314	14,234,314	-	-	-	-	-	-	-
				36,756,866	36,756,866	-	-	-	-	-	-	-
334	Accessory Electric Equipment											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	3,621,270	3,621,270	-	-	-	-	-	-	-
		P	SG	16,147,761	16,147,761	-	-	-	-	-	-	-
		P	SG	4,084,725	4,084,725	-	-	-	-	-	-	-
				23,853,756	23,853,756	-	-	-	-	-	-	-
335	Misc. Power Plant Equipment											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	896,670	896,670	-	-	-	-	-	-	-
		P	SG	60,955	60,955	-	-	-	-	-	-	-
				957,625	957,625	-	-	-	-	-	-	-
336	Roads, Railroads & Bridges											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	6,495,667	6,495,667	-	-	-	-	-	-	-
		P	SG	1,246,843	1,246,843	-	-	-	-	-	-	-
				7,742,510	7,742,510	-	-	-	-	-	-	-
337	Hydro Plant ARO											
		P	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
HP	Unclassified Hydro Plant - Acct 300											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Hydraulic Plant			367,763,269	367,763,269	-	-	-	-	-	-	-
338XP	Solar Plant											
		P	S	919,203	919,203	-	-	-	-	-	-	-
		P	SG	15,632	15,632	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				934,836	934,836	-	-	-	-	-	-	-
	Total Solar Plant			934,836	934,836	-	-	-	-	-	-	-
338WP	Wind Plant											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	1,318,401,032	1,318,401,032	-	-	-	-	-	-	-
				1,318,401,032	1,318,401,032	-	-	-	-	-	-	-
	Total Wind Plant			1,318,401,032	1,318,401,032	-	-	-	-	-	-	-
338RP	Other Renewable Plant											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
339	Other Renewable Production											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	44,261,440	44,261,440	-	-	-	-	-	-	-
				44,261,440	44,261,440	-	-	-	-	-	-	-
	Total Other Renewable Plant			44,261,440	44,261,440	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
340	Land and Land Rights											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	10,896,182	10,896,182	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				10,896,182	10,896,182	-	-	-	-	-	-	-
341	Structures and Improvements											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	48,721,657	48,721,657	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				48,721,657	48,721,657	-	-	-	-	-	-	-
342	Fuel Holders, Producers & Accessories											
		P	SG	4,562,837	4,562,837	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				4,562,837	4,562,837	-	-	-	-	-	-	-
343	Prime Movers											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	338,946,967	338,946,967	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				338,946,967	338,946,967	-	-	-	-	-	-	-
344	Generators											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	120,894,338	120,894,338	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				120,894,338	120,894,338	-	-	-	-	-	-	-
345	Accessory Electric Plant											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	60,481,872	60,481,872	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				60,481,872	60,481,872	-	-	-	-	-	-	-
346	Misc. Power Plant Equipment											
		P	SG	3,602,084	3,602,084	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				3,602,084	3,602,084	-	-	-	-	-	-	-
347	Other Production ARO											
		P	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
OP	Unclassified Other Prod Plant-Acct 300											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Other Plant			1,951,703,244	1,951,703,244	-	-	-	-	-	-	-
103	Experimental Plant											
		P	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Experimental Plant			-	-	-	-	-	-	-	-	-
	Total Production Plant			4,303,259,121	4,303,259,121	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
350	Land and Land Rights											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	122,101,004	-	122,101,004	-	-	-	-	-	-
				122,101,004	-	122,101,004	-	-	-	-	-	-
351	Energy Storage											
		T	SG	81,211,007	-	81,211,007	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
				81,211,007	-	81,211,007	-	-	-	-	-	-
352	Structures and Improvements											
		T	S	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	131,901,586	-	131,901,586	-	-	-	-	-	-
				131,901,586	-	131,901,586	-	-	-	-	-	-
353	Station Equipment											
		STEP_UP	SG	-	-	-	-	-	-	-	-	-
		STEP_UP	SG	-	-	-	-	-	-	-	-	-
		STEP_UP	SG	831,409,936	47,364,507	784,045,430	-	-	-	-	-	-
				831,409,936	47,364,507	784,045,430	-	-	-	-	-	-
354	Towers and Fixtures											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	718,718,951	-	718,718,951	-	-	-	-	-	-
				718,718,951	-	718,718,951	-	-	-	-	-	-
355	Poles and Fixtures											
		T	S	0	-	0	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	675,412,807	-	675,412,807	-	-	-	-	-	-
				675,412,807	-	675,412,807	-	-	-	-	-	-
356	Clearing and Grading											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	659,541,109	-	659,541,109	-	-	-	-	-	-
				659,541,109	-	659,541,109	-	-	-	-	-	-
357	Underground Conduit											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	1,089,208	-	1,089,208	-	-	-	-	-	-
				1,089,208	-	1,089,208	-	-	-	-	-	-
358	Underground Conductors											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	2,521,216	-	2,521,216	-	-	-	-	-	-
				2,521,216	-	2,521,216	-	-	-	-	-	-
359	Roads and Trails											
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		T	SG	3,369,934	-	3,369,934	-	-	-	-	-	-
				3,369,934	-	3,369,934	-	-	-	-	-	-
TP	Unclassified Trans Plant - Acct 300											
		T	SG	191,901,782	-	191,901,782	-	-	-	-	-	-
				191,901,782	-	191,901,782	-	-	-	-	-	-
TS0	Unclassified Trans Sub Plant - Acct 300											
		T	SG	-	-	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
				-	-	-	-	-	-	-	-	-
	Total Transmission Plant			3,419,178,541	47,364,507	3,371,814,035	-	-	-	-	-	-
360	Land and Land Rights											
		D	S	18,539,263	-	-	18,539,263	-	-	-	-	-
				18,539,263	-	-	18,539,263	-	-	-	-	-
361	Structures and Improvements											
		D	S	42,930,779	-	-	42,930,779	-	-	-	-	-
				42,930,779	-	-	42,930,779	-	-	-	-	-
362	Station Equipment											
		D	S	356,583,387	-	-	356,583,387	-	-	-	-	-
				356,583,387	-	-	356,583,387	-	-	-	-	-
363	Storage Battery Equipment											
		D	S	67,908,356	-	-	67,908,356	-	-	-	-	-
		D	SNPD	9,650,733	-	-	9,650,733	-	-	-	-	-
		D	CN	3,255,887	-	-	3,255,887	-	-	-	-	-
				80,814,976	-	-	80,814,976	-	-	-	-	-
364	Poles, Towers & Fixtures											
		D	S	695,359,584	-	-	695,359,584	-	-	-	-	-
				695,359,584	-	-	695,359,584	-	-	-	-	-
365	Overhead Conductors											
		D	S	450,309,947	-	-	450,309,947	-	-	-	-	-
				450,309,947	-	-	450,309,947	-	-	-	-	-
366	Underground Conduit											
		D	S	146,829,263	-	-	146,829,263	-	-	-	-	-
				146,829,263	-	-	146,829,263	-	-	-	-	-
367	Underground Conductors											
		D	S	285,114,054	-	-	285,114,054	-	-	-	-	-
				285,114,054	-	-	285,114,054	-	-	-	-	-
368	Line Transformers											
		D	S	610,447,978	-	-	610,447,978	-	-	-	-	-
				610,447,978	-	-	610,447,978	-	-	-	-	-
369	Services											
		D	S	419,840,973	-	-	419,840,973	-	-	-	-	-
				419,840,973	-	-	419,840,973	-	-	-	-	-
370	Meters											
		C_METER	S	119,080,187	-	-	-	-	-	-	119,080,187	-
				119,080,187	-	-	-	-	-	-	119,080,187	-
371	Installations on Customers' Premises											
		DL	S	2,960,208	-	-	-	2,960,208	-	-	-	-
				2,960,208	-	-	-	2,960,208	-	-	-	-
372	Leased Property											
		D	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
373	Street Lights											
		DL	S	26,922,926	-	-	-	26,922,926	-	-	-	-
				26,922,926	-	-	-	26,922,926	-	-	-	-
DP	Unclassified Dist Plant - Acct 300											
		D	S	122,182,731	-	-	122,182,731	-	-	-	-	-
				122,182,731	-	-	122,182,731	-	-	-	-	-
DS0	Unclassified Dist Sub Plant - Acct 300											

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional** D	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Distribution Plant			3,377,916,256	-	-	3,228,952,935	29,883,134	-	-	119,080,187	-
389	Land and Land Rights											
		D_SPLIT-TC	S	9,084,974	-	-	8,730,229	67,363	-	-	287,382	-
		B_Center	CN	340,129	-	-	-	-	-	221,576	-	118,553
		G-DGU	SG	-	-	-	-	-	-	-	-	-
		G-SG	SG	433	227	206	-	-	-	-	-	-
		LABOR	SO	2,124,318	779,908	169,460	951,656	10,517	-	62,141	63,671	86,964
				11,549,854	780,135	169,666	9,681,885	77,880	-	283,717	351,052	205,517
390	Structures and Improvements											
		D_SPLIT-TC	S	44,496,575	-	-	42,759,098	329,932	-	-	1,407,545	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-
		B_Center	CN	2,477,134	-	-	-	-	-	1,613,719	-	863,415
		G-DGU	SG	3,337,197	1,859,623	1,477,574	-	-	-	-	-	-
		P	SE	252,390	252,390	-	-	-	-	-	-	-
		LABOR	SO	32,673,063	11,995,378	2,606,385	14,636,946	161,754	-	955,766	979,285	1,337,548
				83,236,359	14,107,391	4,083,959	57,396,044	491,687	-	2,569,485	2,386,830	2,200,963
391	Office Furniture & Equipment											
		D_SPLIT-TC	S	1,045,284	-	-	1,004,468	7,751	-	-	33,065	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-
		B_Center	CN	92,760	-	-	-	-	-	60,428	-	32,332
		G-SG	SG	554,910	290,874	264,036	-	-	-	-	-	-
		P	SE	1,025	1,025	-	-	-	-	-	-	-
		LABOR	SO	4,570,973	1,678,158	364,634	2,047,714	22,630	-	133,712	137,002	187,123
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				6,264,952	1,970,057	628,670	3,052,182	30,380	-	194,140	170,067	219,455
392	Transportation Equipment											
		D_SPLIT-TC	S	27,547,977	-	-	26,472,299	204,262	-	-	871,416	-
		LABOR	SO	1,764,415	647,776	140,750	790,426	8,735	-	51,613	52,883	72,230
		G-SG	SG	6,834,109	3,582,319	3,251,790	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-
		P	SE	42,873	42,873	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				36,189,374	4,272,967	3,392,541	27,262,726	212,997	-	51,613	924,299	72,230
393	Stores Equipment											
		D_SPLIT-TC	S	3,974,550	-	-	3,819,354	29,470	-	-	125,726	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-
		LABOR	SO	79,116	29,046	6,311	35,443	392	-	2,314	2,371	3,239
		G-SG	SG	2,169,330	1,137,125	1,032,206	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				6,222,996	1,166,171	1,038,517	3,854,796	29,862	-	2,314	128,097	3,239
394	Tools, Shop & Garage Equipment											
		D_SPLIT-TC	S	10,470,028	-	-	10,061,200	77,633	-	-	331,195	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-
		G-SG	SG	6,225,784	3,263,445	2,962,338	-	-	-	-	-	-
		LABOR	SO	447,599	164,329	35,706	200,516	2,216	-	13,093	13,416	18,324
		P	SE	33,714	33,714	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				17,177,125	3,461,488	2,998,044	10,261,717	79,849	-	13,093	344,610	18,324

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
395	Laboratory Equipment											
		D_SPLIT-TC	S	10,534,808	-	-	10,123,450	78,113	-	-	333,244	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-
		LABOR	SO	1,238,110	454,552	98,766	554,651	6,130	-	36,218	37,109	50,685
		P	SE	328,656	328,656	-	-	-	-	-	-	-
		G-SG	SG	1,638,898	859,081	779,817	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				13,740,472	1,642,290	878,583	10,678,101	84,243	-	36,218	370,353	50,685
396	Power Operated Equipment											
		D_SPLIT-TC	S	49,430,917	-	-	47,500,766	366,520	-	-	1,563,631	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-
		G-SG	SG	8,899,329	4,664,871	4,234,459	-	-	-	-	-	-
		LABOR	SO	1,586,273	582,374	126,540	710,622	7,853	-	46,402	47,544	64,938
		G-DGU	SG	-	-	-	-	-	-	-	-	-
		P	SE	20,062	20,062	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				59,936,580	5,267,306	4,360,998	48,211,387	374,373	-	46,402	1,611,175	64,938
397	Communication Equipment											
		D_SPLIT-TC	S	(2,706,709)	-	-	(2,601,019)	(20,070)	-	-	(85,620)	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-
		LABOR	SO	172,919,153	63,484,426	13,794,052	77,464,679	856,071	-	5,058,305	5,182,774	7,078,846
		B_Center	CN	68,523,954	-	-	-	-	-	44,639,646	-	23,884,307
		G-SG	SG	(2,036,783)	(1,067,646)	(969,138)	-	-	-	-	-	-
		P	SE	2,798	2,798	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-
				236,702,412	62,419,578	12,824,914	74,863,660	836,001	-	49,697,952	5,097,154	30,963,154
398	Misc. Equipment											
		D_SPLIT-TC	S	1,379,092	-	-	1,325,242	10,226	-	-	43,624	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-
		B_Center	CN	24,128	-	-	-	-	-	15,718	-	8,410
		LABOR	SO	1,020,903	374,808	81,439	457,346	5,054	-	29,864	30,599	41,793
		P	SE	1,064	1,064	-	-	-	-	-	-	-
		G-SG	SG	817,168	428,345	388,823	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				3,242,354	804,216	470,262	1,782,588	15,280	-	45,582	74,223	50,203
399	Coal Mine											
		P	SE	10,661,525	10,661,525	-	-	-	-	-	-	-
				10,661,525	10,661,525	-	-	-	-	-	-	-
399L	WIDCO Capital Lease											
		P	SE	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-
1011390	General Capital Leases											
		D_SPLIT-TC	S	7,816,249	-	-	7,511,044	57,956	-	-	247,249	-
		P	SG	1,730,671	1,730,671	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-
				9,546,920	1,730,671	-	7,511,044	57,956	-	-	247,249	-
	Remove Capital Leases			(9,546,920)	(1,730,671)	-	(7,511,044)	(57,956)	-	-	(247,249)	-
1011346	General Gas Line Capital Leases											
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-
GP	Unclassified Gen Plant - Acct 300											

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
		D_SPLIT-TC	S	-	-	-	-	-	-	-	-	-
		LABOR	SO	55,352,729	20,321,845	4,415,580	24,797,030	274,035	-	1,619,202	1,659,045	2,265,992
		B_Center	CN	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-
				55,352,729	20,321,845	4,415,580	24,797,030	274,035	-	1,619,202	1,659,045	2,265,992
399G	Unclassified Gen Plant - Acct 300											
		D_SPLIT-TC	S	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total General Plant			540,276,733	126,874,969	35,261,735	271,842,117	2,506,586	-	54,559,719	13,116,906	36,114,700
301	Organization											
		D_SPLIT-TC	S	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
302	Franchise & Consent											
		D_SPLIT-TC	S	-	-	-	-	-	-	-	-	-
		I-SG	SG	6,803,675	4,462,406	2,341,269	-	-	-	-	-	-
		I-DGP	SG	28,714,551	28,714,551	-	-	-	-	-	-	-
		I-DGU	SG	2,829,784	2,829,784	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-
		I-DGU	SG	-	-	-	-	-	-	-	-	-
				38,348,009	36,006,740	2,341,269	-	-	-	-	-	-
303	Miscellaneous Intangible Plant											
		D_SPLIT-TC	S	4,597,089	-	-	4,417,585	34,086	-	-	145,418	-
		LABOR	SG	47,641,010	17,490,614	3,800,403	21,342,318	235,856	-	1,393,615	1,427,908	1,950,295
		LABOR	SO	(3,881,746)	(1,425,119)	(309,653)	(1,738,953)	(19,217)	-	(113,551)	(116,345)	(158,908)
		P	SE	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	(958,104)	-	-	-	-	-	(424,759)	(223,557)	(309,787)
		I-DGP	SG	-	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-
				47,398,249	16,065,495	3,490,750	24,020,950	250,725	-	855,305	1,233,424	1,481,600
303	Less Non-Regulated Plant											
		I-SITUS	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
IP	Unclassified Intangible Plant - Acct 300											
		D_SPLIT-TC	S	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-
		I-DGU	SG	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Intangible Plant			85,746,258	52,072,235	5,832,019	24,020,950	250,725	-	855,305	1,233,424	1,481,600
	Total Electric Plant In Service			11,726,376,909	4,529,570,832	3,412,907,789	3,524,816,002	32,640,446	-	55,415,024	133,430,517	37,596,300
105	Plant Held For Future Use											
		D_SPLIT-TC	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		G	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
114	Electric Plant Acquisition Adjustments											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	40,163,621	40,163,621	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				40,163,621	40,163,621	-	-	-	-	-	-	-
115	Accum Provision for Asset Acquisition Adjustments											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	(39,479,406)	(39,479,406)	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				(39,479,406)	(39,479,406)	-	-	-	-	-	-	-
128	Pensions											
		LABOR	SO	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
124	Weatherization											
		DSM	S	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
182W	Weatherization											
		DSM	S	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-
		DSM	SGCT	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
186W	Weatherization											
		DSM	S	-	-	-	-	-	-	-	-	-
		DSM	CN	-	-	-	-	-	-	-	-	-
		DSM	CNP	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Weatherization			-	-	-	-	-	-	-	-	-
151	Fuel Stock											
		P	DEU	-	-	-	-	-	-	-	-	-
		P	SE	93,119,143	93,119,143	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
				93,119,143	93,119,143	-	-	-	-	-	-	-
152	Fuel Stock - Undistributed											
		P	SE	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
25316	DG&T Working Capital Deposit											
		P	SE	(1,759,327)	(1,759,327)	-	-	-	-	-	-	-
				(1,759,327)	(1,759,327)	-	-	-	-	-	-	-
25317	DG&T Working Capital Deposit											
		P	SE	(1,524,836)	(1,524,836)	-	-	-	-	-	-	-
				(1,524,836)	(1,524,836)	-	-	-	-	-	-	-
25319	Provo Working Capital Deposit											
		P	SE	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Fuel Stock			89,834,980	89,834,980	-	-	-	-	-	-	-
154	Materials and Supplies											
		MSS	S	196,859,862	143,237,455	2,743,626	49,269,350	-	-	-	1,609,431	-
		MSS	SG	44,237,807	32,187,927	616,540	11,071,673	-	-	-	361,667	-
		MSS	SE	-	-	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
		MSS	SO	(774,749)	(563,716)	(10,798)	(193,901)	-	-	-	(6,334)	-
		MSS	SG	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-
		MSS	SNPD	(413,942)	(301,189)	(5,769)	(103,600)	-	-	-	(3,384)	-
		MSS	SG	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-
				239,908,978	174,560,477	3,343,599	60,043,522	-	-	-	1,961,380	-
158	Allowances											
		MSS	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
163	Stores Expense Undistributed											
		MSS	SO	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
25318	Provo Working Capital Deposit											
		MSS	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Materials & Supplies			239,908,978	174,560,477	3,343,599	60,043,522	-	-	-	1,961,380	-
165	Prepayments											
		LABOR	S	6,166,939	2,264,090	491,947	2,762,678	30,531	-	180,398	184,837	252,458
		GP-TC	GPS	22,360	8,863	6,633	6,408	50	-	109	221	75
		PT-TC	SG	1,848,756	1,032,794	815,962	-	-	-	-	-	-
		P	SE	(23,860)	(23,860)	-	-	-	-	-	-	-
		LABOR	SO	43,044,346	15,803,024	3,433,720	19,283,095	213,100	-	1,259,152	1,290,135	1,762,120
				51,058,541	19,084,911	4,748,262	22,052,181	243,681	-	1,439,659	1,475,193	2,014,653
182M	Misc Regulatory Assets											
		DDS2	S	-	-	-	-	-	-	-	-	-
		DEFSG	SG	(0)	(0)	(0)	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-
		DEFSG	SG-P	-	-	-	-	-	-	-	-	-
		P	SE	22,244,569	22,244,569	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		LABOR	SO	32,572,358	11,958,406	2,598,352	14,591,832	161,256	-	952,821	976,266	1,333,425
				54,816,928	34,202,975	2,598,352	14,591,832	161,256	-	952,821	976,266	1,333,425
186M	Misc Deferred Debits											
		LABOR	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		DEFSG	SG	37,822,624	35,984,447	1,838,177	-	-	-	-	-	-
		LABOR	SO	280,848	103,109	22,404	125,815	1,390	-	8,215	8,418	11,497
		P	SE	82,215	82,215	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		GP-TC	EXCTAX	-	-	-	-	-	-	-	-	-
				38,185,687	36,169,770	1,860,581	125,815	1,390	-	8,215	8,418	11,497
CWC	Cash Working Capital											
		CWC-TC	S	36,514,128	25,733,863	2,800,229	7,001,159	40,598	-	269,896	299,936	368,447
		CWC-TC	SO	-	-	-	-	-	-	-	-	-
		CWC-TC	SE	-	-	-	-	-	-	-	-	-
				36,514,128	25,733,863	2,800,229	7,001,159	40,598	-	269,896	299,936	368,447
	Other Working Capital											
131	Cash	GP-TC	SNP	-	-	-	-	-	-	-	-	-
135	Working Funds	GP-TC	SG	-	-	-	-	-	-	-	-	-
141	Notes Receivable	GP-TC	SO	-	-	-	-	-	-	-	-	-
143	Other A/R	LABOR	SO	43,038,287	15,800,800	3,433,237	19,280,381	213,070	-	1,258,974	1,289,954	1,761,872
232	A/P	LABOR	S	-	-	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
232	A/P	LABOR	SO	(2,079,999)	(763,638)	(165,925)	(931,802)	(10,297)	-	(60,845)	(62,342)	(85,150)
232	A/P	P	SE	(1,998,720)	(1,998,720)	-	-	-	-	-	-	-
232	A/P	P	SG	(1,305,679)	(1,305,679)	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	S	-	-	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	SO	-	-	-	-	-	-	-	-	-
253	Other Deferred Credits - Misc	P	SE	-	-	-	-	-	-	-	-	-
230	Asset Retir. Oblig.	P	SG	-	-	-	-	-	-	-	-	-
230	Asset Retir. Oblig.	P	S	-	-	-	-	-	-	-	-	-
254	ARO Reg Liability	P	SG	(9,002,673)	(9,002,673)	-	-	-	-	-	-	-
254	ARO Reg Liability	P	TROJD	-	-	-	-	-	-	-	-	-
2533	Cholla Reclamation	P	SE	(2,641,990)	(2,641,990)	-	-	-	-	-	-	-
				26,009,225	88,100	3,267,311	18,348,578	202,772	-	1,198,129	1,227,612	1,676,722
	Total Working Capital			62,523,353	25,821,963	6,067,540	25,349,737	243,371	-	1,468,026	1,527,547	2,045,169
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	(14,356,267)	(14,356,267)	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				(14,356,267)	(14,356,267)	-	-	-	-	-	-	-
	Total Miscellaneous Rate Base			(14,356,267)	(14,356,267)	-	-	-	-	-	-	-
	Total Rate Base Additions			762,565,393	540,563,502	21,961,933	182,206,610	649,698	-	3,868,721	7,910,185	5,404,745
235	Customer Service Deposits											
		C_BILLING	S	-	-	-	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
2281	Prop Ins	LABOR	S	48,747,812	17,896,958	3,888,695	21,838,146	241,336	-	1,425,992	1,461,081	1,995,605
2281	Prop Ins	LABOR	SO	-	-	-	-	-	-	-	-	-
2282	Inj & Dam	LABOR	SO	-	-	-	-	-	-	-	-	-
2283	Pen & Ben	LABOR	SO	(210,255)	(77,192)	(16,772)	(94,191)	(1,041)	-	(6,150)	(6,302)	(8,607)
2282	Prov for Injuries & Damages	LABOR	S	3,443,229	1,264,125	274,672	1,542,505	17,046	-	100,723	103,201	140,957
25335	Reg Liabilities	LABOR	SE	(21,419,862)	(7,863,950)	(1,708,698)	(9,595,714)	(106,043)	-	(626,583)	(642,001)	(876,872)
				30,560,924	11,219,941	2,437,896	13,690,746	151,298	-	893,981	915,979	1,251,082
22841	Accum Misc. Operating Provisions											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	(65,195)	(65,195)	-	-	-	-	-	-	-
				(65,195)	(65,195)	-	-	-	-	-	-	-
254105	ARO	P	S	-	-	-	-	-	-	-	-	-
230	ARO	P	TROJD	(2,206,591)	(2,206,591)	-	-	-	-	-	-	-
254105	ARO	P	TROJD	-	-	-	-	-	-	-	-	-
254		P	S	(302,351,746)	(302,351,746)	-	-	-	-	-	-	-
254		P	SO	(14,384,946)	(14,384,946)	-	-	-	-	-	-	-
				(318,943,284)	(318,943,284)	-	-	-	-	-	-	-
252	Customer Advances for Construction											
		D_SPLIT-TC	S	(10,054,115)	-	-	(9,661,527)	(74,549)	-	-	(318,038)	-
		T	SE	-	-	-	-	-	-	-	-	-
		T	SG	(78,355,133)	-	(78,355,133)	-	-	-	-	-	-
		D_SPLIT-TC	SO	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-
				(88,409,248)	-	(78,355,133)	(9,661,527)	(74,549)	-	-	(318,038)	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
25398	SO2 Emissions											
		P	SE	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
25399	Other Deferred Credits											
		D_SPLIT-TC	S	(149,453)	-	-	(143,617)	(1,108)	-	-	(4,728)	-
		LABOR	SO	(14,405,106)	(5,288,598)	(1,149,120)	(6,453,229)	(71,315)	-	(421,384)	(431,753)	(589,706)
		P	SG	(51,707,403)	(51,707,403)	-	-	-	-	-	-	-
		P	SE	(284,215)	(284,215)	-	-	-	-	-	-	-
				(66,546,177)	(57,280,216)	(1,149,120)	(6,596,847)	(72,423)	-	(421,384)	(436,481)	(589,706)
190	Accumulated Deferred Income Taxes											
		D_SPLIT-TC	S	61,529,569	-	-	59,126,997	456,228	-	-	1,946,344	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-
		LABOR	SO	17,561,174	6,447,296	1,400,884	7,867,091	86,940	-	513,707	526,348	718,907
		P	GPS	-	-	-	-	-	-	-	-	-
		IBT-TC	IBT	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	2,294,589	-	-	-	-	-	2,294,589	-	-
		P	TROJD	333,188	333,188	-	-	-	-	-	-	-
		P	SG	2,548,712	2,548,712	-	-	-	-	-	-	-
		P	SE	1,522,580	1,522,580	-	-	-	-	-	-	-
		LABOR	SNP	-	-	-	-	-	-	-	-	-
		D_SPLIT-TC	SNPD	806,955	-	-	775,446	5,983	-	-	25,526	-
		P	SG	-	-	-	-	-	-	-	-	-
				86,596,767	10,851,776	1,400,884	67,769,533	549,152	-	2,808,296	2,498,218	718,907
281	Accumulated Deferred Income Taxes											
		P	S	-	-	-	-	-	-	-	-	-
		PT-TC	SG	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
282	Accumulated Deferred Income Taxes											
		GP-TC	S	(83,200,282)	(32,978,132)	(24,681,146)	(23,843,614)	(187,648)	-	(407,404)	(822,270)	(280,068)
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		ACCMDIT	DITBAL	4	2	1	1	-	-	0	0	0
		PT-TC	SNPD	-	-	-	-	-	-	-	-	-
		PT-TC	CIAC	-	-	-	-	-	-	-	-	-
		C_SERVICE	SNP	(113,596)	-	-	-	-	-	-	-	(113,596)
		P	SG-U	-	-	-	-	-	-	-	-	-
		LABOR	SO	(30,102,947)	(11,051,802)	(2,401,363)	(13,485,580)	(149,031)	-	(880,584)	(902,253)	(1,232,334)
		P	SG	-	-	-	-	-	-	-	-	-
		P	SE	(73,483)	(73,483)	-	-	-	-	-	-	-
		P	SG	(737,753,973)	(737,753,973)	-	-	-	-	-	-	-
				(851,244,277)	(781,857,389)	(27,082,508)	(37,329,194)	(336,678)	-	(1,287,988)	(1,724,523)	(1,625,998)
283	Accumulated Deferred Income Taxes											
		GP-TC	S	(1,516,241)	(600,993)	(449,789)	(434,526)	(3,420)	-	(7,425)	(14,985)	(5,104)
		P	SG	(352,565)	(352,565)	-	-	-	-	-	-	-
		P	SE	(386,161)	(386,161)	-	-	-	-	-	-	-
		LABOR	SO	(8,930,987)	(3,278,865)	(712,440)	(4,000,922)	(44,215)	-	(261,253)	(267,682)	(365,611)
		GP-TC	GPS	(2,091,007)	(828,813)	(620,292)	(599,243)	(4,716)	-	(10,239)	(20,665)	(7,039)
		LABOR	SNP	(98,219)	(36,060)	(7,835)	(44,001)	(486)	-	(2,873)	(2,944)	(4,021)
		P	TROJD	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		IBT-TC	SG	-	-	-	-	-	-	-	-	-
				(13,375,181)	(5,483,458)	(1,790,356)	(5,078,691)	(52,837)	-	(281,790)	(306,276)	(381,774)
	Total Accumulated Deferred Income Taxes			(778,022,691)	(776,489,070)	(27,471,979)	25,361,649	159,637	-	1,238,518	467,419	(1,288,865)
255	Accumulated Investment Tax Credit											
		LABOR	S	-	-	-	-	-	-	-	-	-
		LABOR	ITC84	-	-	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
		LABOR	ITC85	-	-	-	-	-	-	-	-	-
		LABOR	ITC86	-	-	-	-	-	-	-	-	-
		LABOR	ITC88	-	-	-	-	-	-	-	-	-
		LABOR	ITC89	-	-	-	-	-	-	-	-	-
		LABOR	ITC90	-	-	-	-	-	-	-	-	-
		LABOR	SG	(26,013)	(9,550)	(2,075)	(11,653)	(129)	-	(761)	(780)	(1,065)
				(26,013)	(9,550)	(2,075)	(11,653)	(129)	-	(761)	(780)	(1,065)
	Total Rate Base Deductions			(1,221,451,684)	(1,141,567,373)	(104,540,411)	22,782,367	163,834	-	1,710,354	628,099	(628,554)
108SP	Steam Prod Plant Accumulated Depr											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	(1,679,088,466)	(1,679,088,466)	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				(1,679,088,466)	(1,679,088,466)	-	-	-	-	-	-	-
108NP	Nuclear Prod Plant Accumulated Depr											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
108HP	Hydraulic Prod Plant Accum Depr											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	(115,443,640)	(115,443,640)	-	-	-	-	-	-	-
		P	SG	(39,088,765)	(39,088,765)	-	-	-	-	-	-	-
		P	SG	(4,966,332)	(4,966,332)	-	-	-	-	-	-	-
				(159,498,737)	(159,498,737)	-	-	-	-	-	-	-
108RP	Other Renewable Prod Plant Accum Depr											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	(29,897,494)	(29,897,494)	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				(29,897,494)	(29,897,494)	-	-	-	-	-	-	-
108XP	Solar Prod Plant Accum Depr											
		P	S	(250,088)	(250,088)	-	-	-	-	-	-	-
		P	SG	(18,667)	(18,667)	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				(268,755)	(268,755)	-	-	-	-	-	-	-
108OP	Other Production Plant - Accum Depr											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	(231,331,674)	(231,331,674)	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				(231,331,674)	(231,331,674)	-	-	-	-	-	-	-
108WP	Wind Prod Plant Accum Depr											
		P	S	(149,452,701)	(149,452,701)	-	-	-	-	-	-	-
		P	SG	(142,952,545)	(142,952,545)	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				(292,405,247)	(292,405,247)	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
108EP	Experimental Plant - Accum Depr											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Total Production Plant Accum Depreciation			(2,392,490,373)	(2,392,490,373)	-	-	-	-	-	-	-
108TP	Transmission Plant Accumulated Depr											
		T_Split-TC	S	0	0	0	-	-	-	-	-	-
		T_Split-TC	SG	-	-	-	-	-	-	-	-	-
		T_Split-TC	SG	-	-	-	-	-	-	-	-	-
		T_Split-TC	SG	(828,958,596)	(12,373,155)	(816,585,440)	-	-	-	-	-	-
				(828,958,596)	(12,373,155)	(816,585,440)	-	-	-	-	-	-
	Total Transmission Plant Accum Depreciation			(828,958,596)	(12,373,155)	(816,585,440)	-	-	-	-	-	-
108360	Land and Land Rights											
		D	S	(3,371,639)	-	-	(3,371,639)	-	-	-	-	-
				(3,371,639)	-	-	(3,371,639)	-	-	-	-	-
108361	Structures and Improvements											
		D	S	(12,260,514)	-	-	(12,260,514)	-	-	-	-	-
				(12,260,514)	-	-	(12,260,514)	-	-	-	-	-
108362	Station Equipment											
		D	S	(126,265,511)	-	-	(126,265,511)	-	-	-	-	-
				(126,265,511)	-	-	(126,265,511)	-	-	-	-	-
108363	Storage Battery Equipment											
		D	S	(29,839,846)	-	-	(29,839,846)	-	-	-	-	-
		D	SNPD	(7,950,357)	-	-	(7,950,357)	-	-	-	-	-
		D	CN	(3,255,887)	-	-	(3,255,887)	-	-	-	-	-
				(41,046,090)	-	-	(41,046,090)	-	-	-	-	-
108364	Poles, Towers & Fixtures											
		D	S	(302,470,250)	-	-	(302,470,250)	-	-	-	-	-
				(302,470,250)	-	-	(302,470,250)	-	-	-	-	-
108365	Overhead Conductors											
		D	S	(161,143,458)	-	-	(161,143,458)	-	-	-	-	-
				(161,143,458)	-	-	(161,143,458)	-	-	-	-	-
108366	Underground Conduit											
		D	S	(59,920,607)	-	-	(59,920,607)	-	-	-	-	-
				(59,920,607)	-	-	(59,920,607)	-	-	-	-	-
108367	Underground Conductors											
		D	S	(121,112,830)	-	-	(121,112,830)	-	-	-	-	-
				(121,112,830)	-	-	(121,112,830)	-	-	-	-	-
108368	Line Transformers											
		D	S	(289,615,432)	-	-	(289,615,432)	-	-	-	-	-
				(289,615,432)	-	-	(289,615,432)	-	-	-	-	-
108369	Services											
		D	S	(178,846,843)	-	-	(178,846,843)	-	-	-	-	-
				(178,846,843)	-	-	(178,846,843)	-	-	-	-	-
108370	Meters											
		C_METER	S	(46,256,795)	-	-	-	-	-	-	(46,256,795)	-
				(46,256,795)	-	-	-	-	-	-	(46,256,795)	-
108371	Installations on Customers' Premises											
		DL	S	(2,200,269)	-	-	-	(2,200,269)	-	-	-	-
				(2,200,269)	-	-	-	(2,200,269)	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
108372	Leased Property	D	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
108373	Street Lights	DL	S	(12,993,031)	-	-	-	(12,993,031)	-	-	-	-
				(12,993,031)	-	-	-	(12,993,031)	-	-	-	-
108D00	Unclassified Dist Plant - Acct 300	D_SPLIT-TC	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
108DS	Unclassified Dist Sub Plant - Acct 300	D_SPLIT-TC	S	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
108DP	Unclassified Dist Sub Plant - Acct 300	D_SPLIT-TC	S	1,460,620	-	-	1,403,587	10,830	-	-	46,203	-
				1,460,620	-	-	1,403,587	10,830	-	-	46,203	-
	Total Distribution Plant Accum Depreciation			(1,356,042,651)	-	-	(1,294,649,589)	(15,182,470)	-	-	(46,210,592)	-
108GP	General Plant Accumulated Depr	D_SPLIT-TC	S	(68,620,248)	-	-	(65,940,803)	(508,804)	-	-	(2,170,641)	-
		G-DGP	SG	45,923	25,590	20,333	-	-	-	-	-	-
		G-DGU	SG	142,389	79,345	63,044	-	-	-	-	-	-
		G-SG	SG	(16,736,655)	(8,773,058)	(7,963,597)	-	-	-	-	-	-
		B_Center	CN	(66,963,296)	-	-	-	-	-	(43,622,962)	-	(23,340,334)
		LABOR	SO	(166,527,847)	(61,137,963)	(13,284,206)	(74,601,489)	(824,429)	-	(4,871,344)	(4,991,212)	(6,817,204)
		P	SE	(418,811)	(418,811)	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-
				(319,078,546)	(70,224,896)	(21,164,427)	(140,542,292)	(1,333,233)	-	(48,494,306)	(7,161,853)	(30,157,537)
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 Depreciation			(319,078,546)	(70,224,896)	(21,164,427)	(140,542,292)	(1,333,233)	-	(48,494,306)	(7,161,853)	(30,157,537)
	Total Accum Depreciation - Plant In Service			(4,896,570,165)	(2,475,088,425)	(837,749,867)	(1,435,191,881)	(16,515,704)	-	(48,494,306)	(53,372,445)	(30,157,537)
111OP	Accum Prov for Amort-Other	P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
111XP	Accum Prov for Amort-Solar	P	S	(279,419)	(279,419)	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				(279,419)	(279,419)	-	-	-	-	-	-	-

Results of Operations ($) per 2020 Protocol, for the 12 Months Ending December 2027, by FERC Account												
FERC		**Functional**										
111GP	Accum Prov for Amort-General											
		D_SPLIT-TC	S	(5,403,828)	-	-	(5,192,823)	(40,068)	-	-	(170,937)	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-
		LABOR	SO	(542,458)	(199,155)	(43,273)	(243,011)	(2,686)	-	(15,868)	(16,259)	(22,207)
		P	SE	-	-	-	-	-	-	-	-	-
				(5,946,286)	(199,155)	(43,273)	(5,435,834)	(42,754)	-	(15,868)	(187,196)	(22,207)
111HP	Accum Prov for Amort-Hydro											
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	(1,394,232)	(1,394,232)	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				(1,394,232)	(1,394,232)	-	-	-	-	-	-	-
111IP	Accum Prov for Amort-Intangible Plant											
		I-SITUS	S	(170,171)	-	(115,810)	(54,361)	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-
		I-DGU	SG	5,154	5,154	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-
		I-SG	SG	(24,447,795)	(16,034,861)	(8,412,934)	-	-	-	-	-	-
		I-SG	SG	(15,706,515)	(10,301,616)	(5,404,900)	-	-	-	-	-	-
		I-SG	SG	(2,108,080)	(1,382,651)	(725,429)	-	-	-	-	-	-
		CUST	CN	958,104	-	-	-	-	-	424,759	223,557	309,787
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		PTD-TC	SO	3,881,746	1,548,471	1,223,374	1,109,901	-	-	-	-	-
				(37,587,557)	(26,165,503)	(13,435,698)	1,055,541	-	-	424,759	223,557	309,787
111IP	Less Non-Regulated Plant											
		NUTIL	OTH	-	-	-	-	-	-	-	-	-
				(37,587,557)	(26,165,503)	(13,435,698)	1,055,541	-	-	424,759	223,557	309,787
111390	Accum Amtr - Capital Lease											
		LABOR	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
	Remove Capital Lease Amtr			-	-	-	-	-	-	-	-	-
	Total Accum Provision for Amortization			(45,207,495)	(28,038,310)	(13,478,971)	(4,380,293)	(42,754)	-	408,891	36,361	287,580

Docket No. UE 470
Exhibit PAC/903
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Functional Factors

May 2026

Functional Factors									
		Production	Transmission	Distribution	Dist-Lighting	Ancillary	Billing	Metering	C. Service
Deferred Income Tax - Balance	ACCMDIT	45%	30%	24%	0%	0%	0%	0%	0%
Ancillary Function	ANC	0%	0%	0%	0%	100%	0%	0%	0%
Business Centers	B_CENTER	0%	0%	0%	0%	0%	65%	0%	35%
Book Depreciation	BOOKDEPR	60%	17%	22%	0%	0%	0%	1%	0%
Customer Billing	C_BILLING	0%	0%	0%	0%	0%	100%	0%	0%
Customer Metering	C_METER	0%	0%	0%	0%	0%	0%	100%	0%
Customer Other	C_SERVICE	0%	0%	0%	0%	0%	0%	0%	100%
CSS System	CSS_SYS	0%	0%	0%	0%	0%	44%	23%	32%
Customer	CUST	0%	0%	0%	0%	0%	44%	23%	32%
Supervision	CUST901	0%	0%	0%	0%	0%	41%	18%	41%
Cust. Records & Coll. Exp.	CUST903	0%	0%	0%	0%	0%	44%	12%	44%
Misc. Customer Acct. Exp.	CUST905	0%	0%	0%	0%	0%	0%	0%	100%
Distribution Only	D	0%	0%	100%	0%	0%	0%	0%	0%
Distribution Only-LGT	DL	0%	0%	0%	100%	0%	0%	0%	0%
Deferred Debits - Situs	DDS2	129%	-5%	-22%	0%	0%	0%	0%	-1%
Deferred Debit - System Generation	DEFSG	95%	5%	0%	0%	0%	0%	0%	0%
Demand Side Management	DSM	0%	0%	100%	0%	0%	0%	0%	0%
Distribution Poles & Wires	DPW	0%	0%	97%	0%	0%	0%	3%	0%
Environmental Services Department	ESD	30%	10%	60%	0%	0%	0%	0%	0%
FERC Fees	FERC	34%	66%	0%	0%	0%	0%	0%	0%
General Plant	G	21%	30%	40%	0%	0%	3%	2%	2%
General Plant - DGP Factor	G-DGP	56%	44%	0%	0%	0%	0%	0%	0%
General Plant - DGU Factor	G-DGU	56%	44%	0%	0%	0%	0%	0%	0%
General Plant - SG Factor	G-SG	52%	48%	0%	0%	0%	0%	0%	0%
General Plant - SITUS Factor	G-SITUS	0%	28%	71%	0%	0%	0%	1%	0%
Intangible Plant	I	46%	22%	13%	0%	0%	6%	8%	6%
Intangible Plant - DGP Factor	I-DGP	100%	0%	0%	0%	0%	0%	0%	0%
Intangible Plant - DGU Factor	I-DGU	100%	0%	0%	0%	0%	0%	0%	0%
Intangible Plant - SG Factor	I-SG	66%	34%	0%	0%	0%	0%	0%	0%
Intangible Plant - SITUS Factor	I-SITUS	0%	68%	32%	0%	0%	0%	0%	0%
Direct Labor Expense	LABOR	37%	8%	45%	0%	0%	3%	3%	4%
Materials & Supplies	MSS	73%	1%	25%	0%	0%	0%	1%	0%
Non-Utility	NUTIL	0%	0%	0%	0%	0%	0%	0%	0%
Other Revenues - SE Factor	OTHSE	0%	100%	0%	0%	0%	0%	0%	0%
Other Revenues - SG Factor	OTHSG	15%	85%	0%	0%	0%	0%	0%	0%
Other Revenues - SO Factor	OTHSO	0%	0%	100%	0%	0%	0%	0%	0%
Production	P	100%	0%	0%	0%	0%	0%	0%	0%
Schedule M Additions	SCHMA	37%	25%	36%	0%	0%	0%	1%	0%
Schedule M Additions - Permanent	SCHMAP	15%	11%	60%	1%	0%	4%	4%	6%
Schedule M Additions - Permanent-SO	SCHMAP-SO	11%	11%	63%	1%	0%	4%	4%	6%
Schedule M Additions - Temporary	SCHMAT	37%	25%	36%	0%	0%	0%	1%	0%
Schedule M Additions - Temporary-SG	SCHMAT-SG	100%	0%	0%	0%	0%	0%	0%	0%
Schedule M Additions - Temporary-SE	SCHMAT-SE	100%	0%	0%	0%	0%	0%	0%	0%
Schedule M Additions - Temporary-SITUS	SCHMAT-SITUS	24%	25%	44%	0%	0%	2%	2%	2%
Schedule M Additions - Temporary-SNP	SCHMAT-SNP	40%	32%	29%	0%	0%	0%	0%	0%
Schedule M Additions - Temporary-SO	SCHMAT-SO	31%	-33%	73%	1%	0%	8%	8%	11%
Schedule M Deductions	SCHMD	37%	28%	32%	0%	0%	1%	1%	1%
Schedule M Deductions - Permanent	SCHMDP	99%	1%	1%	0%	0%	0%	0%	0%
Schedule M Deductions - Temporary	SCHMDT	37%	28%	33%	0%	0%	1%	1%	1%
Schedule M Deductions - Temporary-GPS	SCHMDT-GPS	40%	32%	29%	0%	0%	0%	0%	0%
Schedule M Deductions - Temporary-SG	SCHMDT-SG	98%	2%	0%	0%	0%	0%	0%	0%
Schedule M Deductions - Temporary-SITUS	SCHMDT-SITUS	107%	-2%	-5%	0%	0%	0%	0%	0%
Schedule M Deductions - Temporary-SNP	SCHMDT-SNP	40%	32%	29%	0%	0%	0%	0%	0%
Schedule M Deductions - Temporary-SO	SCHMDT-SO	36%	1%	50%	1%	0%	4%	4%	5%
Step-up Transformers	STEP_UP	6%	94%	0%	0%	0%	0%	0%	0%
Transmission	T	0%	100%	0%	0%	0%	0%	0%	0%
Tax Depreciation	TAXDEPR	33%	36%	31%	0%	0%	0%	0%	0%
Cash Working Capital	CWC-OR	60%	10%	27%	0%	0%	1%	1%	1%
Cash Working Capital	CWC-TC	70%	8%	19%	0%	0%	1%	1%	1%
Distribution Split between Functions	D_SPLIT-OR	0%	0%	96%	1%	0%	0%	4%	0%
Distribution Split between Functions	D_SPLIT-TC	0%	0%	96%	1%	0%	0%	3%	0%
Gross Plant	GP-OR	39%	29%	30%	0%	0%	0%	1%	0%
Gross Plant	GP-TC	40%	30%	29%	0%	0%	0%	1%	0%
Income Before Taxes	IBT-OR	-8%	33%	65%	2%	0%	1%	7%	1%
Income Before Taxes	IBT-TC	16%	53%	17%	-1%	0%	8%	-2%	9%
Net Plant	NP-OR	30%	38%	31%	0%	0%	0%	1%	0%
Net Plant	NP-TC	36%	35%	28%	0%	0%	0%	1%	0%
Production / Transmission	PT-OR	56%	44%						
Production / Transmission	PT-TC	56%	44%						
Prod, Trans, Dist Plant	PTD-OR	39%	31%	30%					
Prod, Trans, Dist Plant	PTD-TC	40%	32%	29%					
Revenue Requirement	REVREQ-OR	50%	19%	28%	0%	0%	1%	1%	1%
Revenue Requirement	REVREQ-TC	62%	14%	21%	0%	0%	1%	1%	1%
Transmission Split	T_SPLIT-OR	1%	99%						
Transmission Split	T_SPLIT-TC	1%	99%						
Transmission / Distribution	TD-OR		50%	50%					
Transmission / Distribution	TD-TC		52%	48%					

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Ancillary Services Revenue Requirement

May 2026

Combined GRC and TAM
Ancillary Services Revenue
12 Months Ending December 2027 Forecast

Oregon Annual Ancillary Service Revenue ($)	30,913,774

Calculation below per the PacifiCorp Open Access Transmission Tariff (OATT) Load and Generation prices on
Schedule 3 (Regulation and Frequency Response Service), Schedule 3A (Generator Regulation and Frequency Response Service),
Schedule 5 (Operating Reserve - Spinning Reserve Service) and Schedule 6 (Operating Reserve - Supplemental Reserve Service).

Sum of 12 Oregon Monthly Peaks (MW)	29,579
Oregon Retail Load (MWh)	17,634,490
Schedule 3 Load Rate ($/MW-month)	115
Schedule 3 Revenue ($)	3,416,088
Schedule 5 Rate ($/MWh)	0.168
Schedule 5 Revenue ($)	2,957,304
Schedule 6 Rate ($/MWh)	0.168
Schedule 6 Revenue ($)	2,957,304
Oregon Load Revenue ($)	9,330,696

Sum of 12 Total System Solar VER Generator Nameplate Capacities (MW)	43,207
Sum of 12 Total System Wind VER Generator Nameplate Capacities (MW)	61,043
Sum of 12 Total System Non-VER Generator Nameplate Capacities (MW)	9,282
Total System Generation MWh at input	63,147,345
Schedule 3A Solar VER Rate ($/MW-month)	465
Schedule 3A VER Revenue ($)	20,104,056
Schedule 3A Wind VER Rate ($/MW-month)	558
Schedule 3A VER Revenue ($)	34,042,398
Schedule 3A Non-VER Rate ($/MW-month)	262
Schedule 3A Non-VER Revenue ($)	2,435,164
Schedule 5 Rate ($/MWh)	0.168
Schedule 5 Revenue ($)	10,589,810
Schedule 6 Rate ($/MWh)	0.168
Schedule 6 Revenue ($)	10,589,810
Generation Revenue ($)	77,761,238
Oregon JAM SG Factor	28%
Oregon-allocated Generation Revenue ($)	21,583,078

Oregon Retail Load is Oregon's Contributions to Monthly Firm System Retail Load at input
All VER Generation is assumed to be Uncommitted
(see OATT Schedule 3A requirements for Committed and Uncommitted)

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Oregon Marginal Cost of Service Study Summary

May 2026

20-Year Marginal Costs

					23			28				30			48						
					Secondary			Secondary				Secondary			Secondary		Primary				
			Total	4	0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100+ kW	Primary	0-300 kW	300+ kW	Primary	1-4 MW	> 4 MW	1-4 MW	> 4 MW	Transmission	41	15,51,53,54
Units	Demand	Peak MW @ Input-System		1,110	90	97	0	65	103	151	3	28	157	11	71	9	60	300	312	34	1
Units	Demand	Peak MW @ Input-Distribution		1,299	96	102	0	68	109	159	3	29	163	11	71	9	60	296	-	42	0
Units	Demand	Peak MW @ Input-Transformer		3,907	825	536	-	232	454	534	-	70	320	-	125	30	-	-	-	266	16
Units	Energy	Annual MWh @ Input		6,024,472	575,840	616,346	3,035	417,460	673,641	1,019,031	18,517	192,198	1,097,071	80,700	515,118	75,844	429,139	2,499,837	2,629,644	243,781	22,175
Units	Customer	Average		557,684	72,880	15,117	64	4,450	3,743	2,354	59	213	580	46	89	3	54	44	10	4,346	7,545
Units	Customer	Annual - Metered		557,684	72,880	15,117	64	4,450	3,743	2,354	59	213	580	46	89	3	54	44	10	7,808	96
$/Unit	Demand	Generation ($/System Peak kW)		138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	-
$/Unit	Demand	Transmission ($/System Peak kW)		24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	-
$/Unit	Demand	Dist-Poles ($/Dist. kW)		26.61	41.96	41.96	41.96	28.58	28.58	28.58	28.58	18.61	18.61	18.61	35.39	2.20	35.39	0.94	-	73.77	41.96
$/Unit	Demand	Dist-Cond ($/Dist. kW)		39.78	54.31	54.31	54.31	41.55	41.55	41.55	41.55	31.91	31.91	31.91	47.63	4.19	47.63	1.79	-	86.44	54.31
$/Unit	Demand	Dist-Substation ($/Dist. kW)		21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	-	21.07	-
$/Unit	Demand	Dist-Transformers ($/Xfmr kW)		4.99	4.99	4.99	-	4.99	4.99	4.99	-	4.99	4.99	-	4.99	4.99	-	-	-	4.99	4.99
$/Unit	Energy	Generation Energy @ Input ($/kWh)		0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
$/Unit	Energy	Transmission Energy @ Input ($/kWh)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
$/Unit	Customer	Dist-Poles ($/Customer)		110.52	178.61	178.61	178.61	118.70	118.70	118.70	118.70	73.29	73.29	73.29	146.77	-	146.77	-	-	331.25	178.61
$/Unit	Customer	Dist-Conductor ($/Customer)		53.98	87.23	87.23	87.23	57.97	57.97	57.97	57.97	35.80	35.80	35.80	71.68	-	71.68	-	-	161.78	87.23
$/Unit	Customer	Dist-Transformers ($/Customer)		137.75	275.89	338.86	-	948.63	1,047.92	1,134.77	-	1,323.80	1,324.68	-	1,299.77	1,299.77	-	-	-	1,077.56	474.97
$/Unit	Customer	Dist-Service Drop ($/Customer)		97.15	134.47	255.71	-	263.87	272.19	548.26	-	561.55	1,060.26	-	3,689.30	3,689.30	-	-	-	-	-
$/Unit	Customer	Meters ($/Customer)		24.01	25.44	36.38	1,925.55	35.82	35.52	218.70	1,925.55	219.66	219.75	1,925.55	411.16	411.16	1,925.55	1,925.55	29,190.18	36.14	25.44
$/Unit	Customer	Billing & Collections ($/Customer)		21.96	24.57	24.57	24.57	26.33	26.33	26.33	26.33	26.33	26.33	26.33	213.48	213.48	213.48	213.48	213.48	30.61	20.92
$/Unit	Customer	Uncollectables ($/Customer)		14.37	4.23	4.23	4.23	40.66	40.66	40.66	40.66	280.81	280.81	280.81	4,338.82	4,338.82	4,338.82	4,338.82	4,338.82	35.30	-
$/Unit	Customer	Customer Service / Other ($/Customer)		10.89	10.47	10.47	10.47	12.56	12.56	12.56	12.56	25.69	25.69	25.69	257.67	257.67	257.67	257.67	257.67	12.50	10.04
$000	Demand	Generation	360,535	153,831	12,445	13,511	57	9,004	14,232	20,870	372	3,898	21,744	1,499	9,862	1,302	8,339	41,613	43,212	4,746	-
$000	Demand	Transmission	64,058	27,332	2,211	2,401	10	1,600	2,529	3,708	66	693	3,863	266	1,752	231	1,482	7,394	7,678	843	-
$000	Demand	Dist-Poles	64,369	34,566	4,016	4,292	19	1,939	3,101	4,545	83	549	3,041	201	2,518	19	2,127	278	-	3,069	6
$000	Demand	Dist-Conductor	93,442	51,685	5,199	5,556	25	2,819	4,509	6,609	121	941	5,214	345	3,389	37	2,862	529	-	3,596	7
$000	Demand	Dist-Substations	53,053	27,377	2,017	2,156	10	1,430	2,287	3,352	61	621	3,443	228	1,499	186	1,266	6,243	-	877	-
$000	Demand	Dist-Transformers	36,472	19,480	4,114	2,674	-	1,156	2,265	2,664	-	350	1,594	-	626	148	-	-	-	1,324	78
$000	Demand	Total Demand	671,930	314,271	30,002	30,590	121	17,948	28,923	41,747	703	7,052	38,899	2,539	19,646	1,924	16,075	56,057	50,889	14,454	91
$000	Energy	Generation	609,468	214,296	20,483	21,924	108	14,849	23,962	36,248	659	6,837	39,024	2,871	18,323	2,698	15,265	88,922	93,539	8,672	789
$000	Energy	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
$000	Energy	Total Energy	609,468	214,296	20,483	21,924	108	14,849	23,962	36,248	659	6,837	39,024	2,871	18,323	2,698	15,265	88,922	93,539	8,672	789
$000	Customer	Dist-Poles	81,289	61,633	13,017	2,700	11	528	444	279	7	16	43	3	13	-	8	-	-	2,586	-
$000	Customer	Dist-Conductor	39,701	30,101	6,358	1,319	6	258	217	136	3	8	21	2	6	-	4	-	-	1,263	-
$000	Customer	Dist-Transformers	122,450	76,822	20,107	5,123	-	4,221	3,922	2,671	-	281	769	-	116	4	-	-	-	8,414	-
$000	Customer	Dist-Service Drop	72,403	54,179	9,800	3,866	-	1,174	1,019	1,291	-	119	615	-	328	11	-	-	-	-	-
$000	Customer	Meters	17,903	13,389	1,854	550	123	159	133	515	114	47	128	89	37	1	104	85	292	282	2
$000	Customer	Billing & Collections	15,043	12,245	1,791	371	2	117	99	62	2	6	15	1	19	1	11	9	2	133	158
$000	Customer	Uncollectables	10,076	8,016	308	64	0	181	152	96	2	60	163	13	386	13	233	192	43	153	-
$000	Customer	Customer Service / Other	7,330	6,071	763	158	1	56	47	30	1	5	15	1	23	1	14	11	3	54	76
$000	Customer	Total Customer (Commitment & Billing)	366,196	262,457	53,998	14,151	143	6,695	6,033	5,080	129	542	1,768	109	928	31	374	298	340	12,886	236
$000	Total	Generation	970,003	368,127	32,928	35,435	165	23,853	38,194	57,117	1,031	10,735	60,768	4,369	28,185	4,000	23,604	130,535	136,751	13,417	789
$000	Total	Transmission	64,058	27,332	2,211	2,401	10	1,600	2,529	3,708	66	693	3,863	266	1,752	231	1,482	7,394	7,678	843	-
$000	Total	Distribution	563,180	355,844	64,627	27,685	70	13,526	17,765	21,547	276	2,885	14,739	779	8,495	406	6,266	7,050	-	21,128	91
$000	Total	Customer Billing	25,119	20,261	2,099	435	2	298	251	158	4	65	178	14	405	14	245	201	46	286	158
$000	Total	Customer Metering	17,903	13,389	1,854	550	123	159	133	515	114	47	128	89	37	1	104	85	292	282	2
$000	Total	Customer Service / Other	7,330	6,071	763	158	1	56	47	30	1	5	15	1	23	1	14	11	3	54	76
$000	Total	Total Revenue	1,647,595	791,024	104,482	66,664	371	39,493	58,919	83,075	1,491	14,430	79,691	5,518	38,896	4,653	31,714	145,277	144,768	36,012	1,116

Docket No. UE 470
Exhibit PAC/906
Witness: Kenneth Lee Elder, Jr.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Kenneth Lee Elder, Jr.

Unbundled Revenue Requirement Allocation

May 2026

Revenue Requirement by Function, Schedule, and Voltage

				23		28		30		48				
		Total	4	Secondary	Primary	Secondary	Primary	Secondary	Primary	Secondary	Primary	Transmission	41	15,51,53,54
1	Operating Revenue $000	1,779,189	801,275	164,335	359	193,285	1,741	110,188	6,863	49,035	234,699	177,868	34,896	4,645
2	20-Year Marginal Cost $000													
3	Generation	970,003	368,127	68,363	165	119,165	1,031	71,503	4,369	32,185	154,139	136,751	13,417	789
4	Transmission	64,058	27,332	4,612	10	7,836	66	4,556	266	1,983	8,875	7,678	843	-
5	Distribution, Excl. Subs & Lgting	510,127	328,467	88,139	61	45,770	214	13,559	551	7,215	5,807	-	20,252	91
6	Distribution Substations	53,053	27,377	4,173	10	7,069	61	4,065	228	1,686	7,509	-	877	-
7	Billing	25,119	20,261	2,534	2	707	4	244	14	419	446	46	286	158
8	Metering	17,903	13,389	2,404	123	807	114	174	89	38	189	292	282	2
9	Customer Service / Other	7,330	6,071	922	1	132	1	20	1	24	25	3	54	76
10	Total	1,647,595	791,024	171,147	371	181,486	1,491	94,121	5,518	43,549	176,991	144,768	36,012	1,116
11	Allocation Factors													
12	Generation	100.00%	37.95%	7.05%	0.02%	12.29%	0.11%	7.37%	0.45%	3.32%	15.89%	14.10%	1.38%	0.08%
13	Transmission	100.00%	42.67%	7.20%	0.02%	12.23%	0.10%	7.11%	0.42%	3.10%	13.85%	11.99%	1.32%	0.00%
14	Distribution, Excl. Subs & Lgting	100.00%	64.39%	17.28%	0.01%	8.97%	0.04%	2.66%	0.11%	1.41%	1.14%	0.00%	3.97%	0.02%
15	Distribution Substations	100.00%	51.60%	7.86%	0.02%	13.32%	0.12%	7.66%	0.43%	3.18%	14.15%	0.00%	1.65%	0.00%
16	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%
17	Ancillary Service	100.00%	37.95%	7.05%	0.02%	12.29%	0.11%	7.37%	0.45%	3.32%	15.89%	14.10%	1.38%	0.08%
18	Billing	100.00%	80.66%	10.09%	0.01%	2.81%	0.02%	0.97%	0.06%	1.67%	1.78%	0.18%	1.14%	0.63%
19	Metering	100.00%	74.79%	13.43%	0.69%	4.51%	0.63%	0.97%	0.49%	0.21%	1.05%	1.63%	1.58%	0.01%
20	Customer Service / Other	100.00%	82.83%	12.57%	0.01%	1.81%	0.01%	0.28%	0.02%	0.32%	0.34%	0.04%	0.74%	1.03%
21	Franchise Fees (Operating Rev.)	100.00%	45.04%	9.24%	0.02%	10.86%	0.10%	6.19%	0.39%	2.76%	13.19%	10.00%	1.96%	0.26%
22	Revenue Requirement $000													
23	Generation	882,252	334,824	62,179	150	108,385	937	65,035	3,974	29,273	140,195	124,379	12,203	717
24	Transmission	352,452	150,382	25,374	56	43,117	364	25,068	1,465	10,913	48,832	42,243	4,639	-
25	Distribution, Excl. Subs & Lgting	469,044	302,014	81,041	56	42,084	197	12,467	507	6,634	5,340	-	18,621	84
26	Distribution Substations	48,781	25,172	3,837	9	6,499	56	3,737	209	1,550	6,905	-	806	-
27	Distribution Lighting	3,427	-	-	-	-	-	-	-	-	-	-	-	3,427
28	Ancillary Services	30,685	11,645	2,163	5	3,770	33	2,262	138	1,018	4,876	4,326	424	25
29	Billing	5,992	4,833	604	0	169	1	58	3	100	106	11	68	38
30	Metering	21,769	16,280	2,923	150	981	138	212	108	46	229	355	343	3
31	Customer Service / Other	15,575	12,900	1,959	1	282	2	43	3	50	54	5	115	161
32	Franchise Fees	55,325	24,916	5,110	11	6,010	54	3,426	213	1,525	7,298	5,531	1,085	144
33	Total	1,885,301	882,967	185,189	439	211,296	1,782	112,308	6,621	51,109	213,835	176,850	38,306	4,599
34	Operating Revenue per Rev. Req.	94.37%	90.75%	88.74%	81.76%	91.48%	97.69%	98.11%	103.66%	95.94%	109.76%	100.58%	91.10%	100.99%
35	Change $000	106,112	81,692	20,854	80	18,011	41	2,121	(243)	2,074	(20,865)	(1,018)	3,410	(46)
36	Change per Operating Revenue	5.96%	10.20%	12.69%	22.31%	9.32%	2.37%	1.92%	-3.53%	4.23%	-8.89%	-0.57%	9.77%	-0.98%

Earned Functionalized Revenue Requirement
12 Months Ending December 2027 Forecast

	Total	Production	Transmission	Distribution	Distribution-Lighting	Ancillary	Billing	Metering	Cust. Serv./ Other	Franchise Fees
Earned Revenue Requirement	1,793,305	867,534	312,941	483,725	3,165	30,914	5,817	20,456	15,478	53,275
Study Revenue	1,779,189	860,705	310,477	479,917	3,140	30,670	5,772	20,295	15,356	52,856
Other Revenue										
Schedule 29	216									
Schedule 47 Primary	3,583									
Schedule 47 Transmission	1,092									
Schedule 848 Distribution	1,920									
Schedule 4 Employee Discount	(463)									
Paperless Credit	(1,991)									
Annual Guarantee Adjustment	9,715									
Direct Access Opt Out Amortization	44									
Total	1,793,305									

Target Functionalized Revenue Requirement
12 Months Ending December 2027 Forecast

	Total	Production	Transmission	Distribution	Distribution-Lighting	Ancillary	Billing	Metering	Cust. Serv./ Other	Franchise Fees
Target Revenue Requirement	1,899,345	888,824	355,077	521,682	3,452	30,914	6,037	21,931	15,691	55,737
Study Revenue	1,885,301	882,252	352,452	517,824	3,427	30,685	5,992	21,769	15,575	55,325
Other Revenue										
Schedule 29	260									
Schedule 47 Primary	3,391									
Schedule 47 Transmission	1,178									
Schedule 848 Distribution	1,968									
Schedule 4 Employee Discount	(521)									
Paperless Credit	(1,991)									
Annual Guarantee Adjustment	9,715									
Direct Access Opt Out Amortization	44									
Total	1,899,345									

FERC Transmission Revenue by Schedule and Voltage

	Total	4	23		28		30		48			41	15,51,53,54
			Secondary	Primary	Secondary	Primary	Secondary	Primary	Secondary	Primary	Transmission		
Transmission $000	352,452	150,382	25,374	56	43,117	364	25,068	1,465	10,913	48,832	42,243	4,639	-
Peak MW @ Input	2,602	1,110	187	0	318	3	185	11	81	360	312	34	1
FERC Transmission $000	130,444	55,637	9,388	21	15,952	135	9,274	542	4,038	18,067	15,629	1,716	46
Other (Non-FERC) Transmission $000	222,008	94,745	15,986	35	27,165	229	15,793	923	6,876	30,766	26,614	2,923	(46)

Oregon Contribution to System Retail Coincidental Peaks per JAM tab 'Factors'	
January	2,839
February	2,639
March	2,518
April	2,350
May	2,058
June	2,284
July	2,794
August	2,648
September	2,158
October	2,088
November	2,486
December	2,715
Annual Average	2,465

Network service rate	
$ per MW-year	52,921

Docket No. UE 470
Exhibit PAC/907
Witness: Kenneth Lee Elder, Jr.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Kenneth Lee Elder, Jr.

Oregon Marginal Cost of Service Study

May 2026

Marginal Cost Study Procedures

INTRODUCTION

Customer class marginal costs are developed to illustrate the resources required to produce one additional unit of electricity or add one additional customer to the system. One, five, ten and twenty years marginal costs are calculated because the Company believes the Commission should have information about the Company's marginal costs over different time periods. Twenty-year (or long run) marginal costs, however, are the primary time frame used in setting retail tariff prices.

The one-year marginal costs include only changes in operating costs, while ten- and twenty-year marginal costs also include the cost of expanding facilities. The cost of added facilities results in long-run costs, which are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. There are no short-run demand-related generation, transmission or distribution costs. Long-run costs include ten or twenty years of generation costs, transmission and distribution costs.

One, ten and twenty-year marginal costs are summarized by customer class and load size group and shown in mills/kilowatt-hour (kWh). Marginal commitment costs and billing expenses, which are sometimes referred to as customer costs, are shown in dollars per customer per year. Costs are shown for both the one-year and the long-run time periods.

Unit costs are adjusted to 2027 values and are shown by generation, transmission, and distribution functional categories and by demand, energy, and commitment and billing costing classifications. Also included are energy usage, peak demand, and number of customers by customer class for the 12 month period ending December 2027.

One, ten and twenty-year marginal costs in mills/kilowatt-hour (kWh) are shown on "Demand and Energy in Mills per kWh" (Sheet 'Table 1'). Marginal commitment costs and billing expenses are shown on "Commitment and Billing $ per Customer per Month" (Sheet 'Table 2'). Billing information, unit costs, and total marginal costs are shown on "20-Year Marginal Cost" (Sheet 'Table 3').

MARGINAL GENERATION COSTS

The development of marginal generation costs for this study are based on a forecast cost of a storage resource, described in the Company's Integrated Resource Plan, and a utility-scale solar resource. The marginal generation capacity costs are determined using the cost per kW-year of the storage resource adjusted for the capacity contribution of the resource and the forecast energy benefit. The generation energy costs are determined by deducting a capacity credit from the utility-scale solar resource.

The marginal generation calculation can be seen in the marginal cost study on page "Generation Demand and Energy" (Sheet 'Generation'). A summarized version of this page is "Table 4 - Marginal Generation Costs in Nominal Dollars" (Sheet 'Table 4').

MARGINAL TRANSMISSION COSTS

The calculation of transmission costs is based on a five-year (2026-2030) analysis of forecasted expenditures to meet increased load on the transmission system. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand.

Unlike growth-related system support and local transmission investments, the Company's investment in bulk power lines is classified both to demand and energy in the same proportions as twenty-year marginal costs of generation resources. Bulk transmission costs are classified this way because they are thought to be an integral part of the generation system. The Company's investments in high voltage bulk transmission lines are being made to move both energy and capacity. It is usually not possible to site a thermal plant close to the customers the plant is intended to serve. Instead, bulk power lines are constructed to transmit the energy being generated, along with the accompanying capacity.

Each year's growth-related transmission investments are adjusted to 2027 dollars and the five years are totaled. The total transmission investment is divided by the capacity added by the investment to determine the marginal investment per kilowatt (kW). An annual charge for including an A&G expense loading factor and a transmission O&M loading factor are added to the per kW investment to arrive at long-run transmission marginal cost.

The marginal transmission calculation including the split between demand and energy can be seen in the marginal cost study on page "Transmission Investment and OMAG Expenses" (Sheet 'Transmission'). A summarized version of this page is "Table 5 - Transmission Investment and Associated Expenses s" (Sheet 'Table 5').

MARGINAL DISTRIBUTION COSTS

Distribution costs are classified into three components: Demand-related, shown in dollars per kW per year, commitment-related, shown in dollars per customer per year, and billing-related, shown in dollars per customer per year. Commitment costs consist of the costs of transformers, poles, and conductor that are not determined by the level of demand customers place on the system. Demand-related costs are the additional costs of larger transformers, substations, poles, and conductors with sufficient capacity to serve the level of demand a customer class places on the system. Billing costs are the costs of meters, service drops, and customer accounting functions.

A summary of distribution marginal costs showing these three components is on page "Table 6 - Distribution and Billing Costs" (Sheet 'Table 6').

Distribution substation costs are determined using the per kW cost of budgeted and forecasted substation additions for the five year period 2026 - 2030. As part of the capital budgeting process the company determines which substations are approaching their maximum design loading. When load can no longer be shifted to adjacent substations, an upgrade, either greater capacity at the substation or a new substation, is required. The capital investment in common year dollars is totaled across all projects and

across the budget-planning horizon to produce total substation investment. This substation investment is then multiplied by a substation utilization factor. The substation utilization factor is calculated by dividing the maximum distribution peak by the installed capacity of existing distribution substations. Applying a utilization factor to distribution substation costs reflects the fact that substation capacity additions are typically done in blocks which result in some substations being close to being fully utilized and others operating well below peak capacity. This weighted substation investment is divided by the associated incremental substation capacity to get dollars per kW. The dollars per kW is adjusted to an annual value by applying a real levelized carrying charge. Substation marginal costs are classified entirely to demand, and are allocated to customer classes based on the distribution peak load for each class. Page "Distribution Substation Costs" (Sheet 'Substation') shows the annualized cost in $ per kW and detailed calculations.

Distribution pole and conductor costs are calculated using the Company's Distribution Circuit Model (Sheet 'Poles&Conductor'). The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics for the state of Oregon. The model determines the cost of the circuit by using current cost estimates to construct one mile of distribution facilities using each of the Company's single and three phase wire sizes. The results are segregated into commitment related and demand related costs for each customer class. A more detailed description of the circuit model is included as an appendix to this narrative.

Distribution line transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers. Commitment and demand costs are separated by the nature of the statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer. Line transformer regression results, demand and commitment costs are shown on page "Transformer Demand and Commitment Costs" (Sheet 'Transformer').

Distribution service drop costs includes the costs of new investments plus associated O&M expense. Average service drop investments are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Incremental service drop O&M is based on the average of ten years of historical expenditures.

Distribution metering costs include the marginal cost of metering equipment with associated O&M expense. Average meter investments are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Meter O&M expense is based on historical expenditures.

The billing customer service/other category includes the costs of billing, payment processing, debt recovery, meter reading expenses and all remaining customer accounting and customer service activities. Customer accounting and customer service expense are

based on the most recent five years of expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

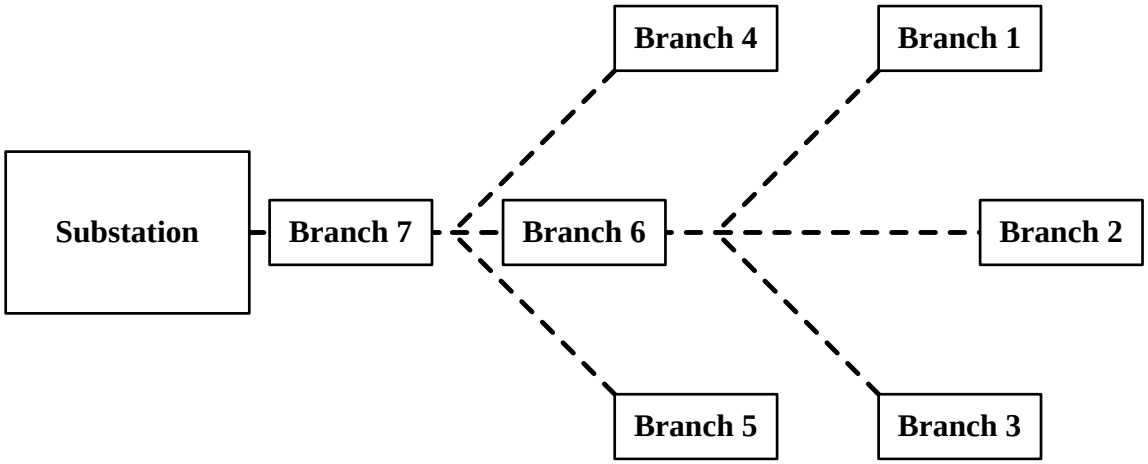
Weighted average installed service drop and meter cost calculations are on Sheet ‘ServdropsMeters’. The customer accounting and informational expense calculation is on page "Customer Accounting Expense” (Sheet ‘CustExpense’). These calculations are brought together on "Table 6 - Distribution and Billing Costs” (Sheet ‘Table 6’) to calculate metering reading, billing, collections and customer service related costs.

Distribution Circuit Model

General Overview

The PacifiCorp Distribution Circuit Model calculates the cost of building a hypothetical circuit (Figure 1, below) with seven branches of equal length using the composite line statistics for a chosen state or service area. A hypothetical circuit is used rather than a sampling of actual existing circuits. This is because the diverse characteristics of PacifiCorp's six state service area, consisting of over 2,000 distribution circuits, makes the selection of any single, or small number of typical circuits impractical. The fundamental concept of the hypothetical circuit is to create a model that reduces the elements of distribution cost assignment to a workable form.

Figure 1 - Circuit Model Diagram



The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and perhaps most importantly, customer location on the circuit. Each customer is assigned cost responsibility for all distribution facilities between the customer's location and the substation (upstream facilities), but no facilities beyond the customer's service location (downstream facilities). The model performs three basic functions. First, it estimates the total cost to build the composite circuit using current construction costs and state specific characteristics. Second, it divides the cost of each branch of the circuit between demand and commitment related costs. Third, it assigns the various types of costs to customer classes.

Required Engineering & Statistical Data

Listed below are the basic statistics that we use to calculate the composite circuit for a given state:

1. Current One Mile Line Construction Cost Estimates for Each Conductor Size
2. Economic Conductor Loading for Each Conductor Size
3. Overhead and Underground Line Miles
4. Number of Poles
5. Number of Circuits -- distribution line points of origin radiating from a substation.

6. Actual Customer Distances from Distribution Substations
7. Number of Customers and Loads by Class
8. Percentages of Three-Phase and Single-Phase Customers by Class

One Mile Line Estimate

The model determines the cost of the circuit by using cost estimates to construct one mile of distribution facilities using each of the Company's single and three-phase wire sizes. These cost estimates are based on typical topography and equipment configuration for an average mile of line construction. Since the number of poles per mile varies between states, we use a factor to adjust the line cost estimate from the system wide average to the state average poles per mile. Figure 2 shows the circuit cost per mile calculation for Oregon.

Figure 2 – Adjusted Oregon Line Costs per Mile

	Poles	Pole Feet	Pole Miles	Poles per Mile	Adj. Factor
California	55,705	12,071,630	2,286	24.36	0.882
Idaho	98,043	22,050,165	4,176	23.48	0.850
Oregon	381,585	73,492,032	13,919	27.41	0.992
Utah	350,360	55,698,348	10,549	33.21	1.202
Washington	100,724	18,245,816	3,456	29.15	1.055
Wyoming	160,270	37,613,177	7,124	22.50	0.814
Total	1,146,687	219,171,167	41,510	27.62	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 Phase - 1/0 ACSR	32,751	0.992	32,502	15,874	48,376
3 Phase - 1/0 ACSR	62,234	0.992	61,761	35,205	96,966
3 Phase - 447 AAC & 4\0 AAC	68,900	0.992	68,377	79,619	147,996
3 Phase -795 AAC & 477 AAC	71,562	0.992	71,019	134,976	205,995

Customer Placement

One of the most significant cost drivers of marginal distribution costs is the distance between the customer and the substation. Costs increase as the distance from the substation increases.

The circuit model takes distance into account by assigning customers to the different branches of the circuit based upon actual customer locations. The actual customer distances are derived from PacifiCorp's outage management system (CADOPS). The system is able to accurately trace the flow of electricity from substation to customer as well as ascertain the exact distance it must travel. Figure 3 shows the customer distribution on the Hypothetical Circuit Branch for Oregon.

Figure 3 Customer Distribution

	Voltage	Load Size	Percentage Distribution by Branch						
			1	2	3	4	5	6	7
Schedule 4			0.48%	0.48%	0.48%	1.96%	1.96%	1.96%	92.66%
Schedule 23	Secondary	0-15 kW	0.98%	0.98%	0.98%	2.88%	2.88%	2.88%	88.41%
		15+ kW	0.98%	0.98%	0.98%	2.88%	2.88%	2.88%	88.41%
	Primary		0.98%	0.98%	0.98%	2.88%	2.88%	2.88%	88.41%
Schedule 28	Secondary	0-50 kW	0.58%	0.58%	0.58%	1.92%	1.92%	1.92%	92.48%
		51-100 kW	0.58%	0.58%	0.58%	1.92%	1.92%	1.92%	92.48%
		100+ kW	0.58%	0.58%	0.58%	1.92%	1.92%	1.92%	92.48%
	Primary		0.58%	0.58%	0.58%	1.92%	1.92%	1.92%	92.48%
Schedule 30	Secondary	0-300 kW	0.33%	0.33%	0.33%	0.99%	0.99%	0.99%	96.02%
		300+ kW	0.33%	0.33%	0.33%	0.99%	0.99%	0.99%	96.02%
	Primary		0.33%	0.33%	0.33%	0.99%	0.99%	0.99%	96.02%
Schedule 48	Secondary	1-4 MW	0.94%	0.94%	0.94%	1.72%	1.72%	1.72%	92.02%
		> 4 MW							
	Primary	1-4 MW	0.94%	0.94%	0.94%	1.72%	1.72%	1.72%	92.02%
		> 4 MW							
Schedule 41			1.31%	1.31%	1.31%	8.01%	8.01%	8.01%	72.02%

Customer Density

The next significant driver of distribution costs is customer density. The model uses state specific line and customer statistics to calculate the average number of customers by circuit branch. Total state distribution line miles and state customers, by class, are divided by the number of distribution circuits in the state to determine the average length of the composite circuit (line miles / number of circuits) and the number of customers on the circuit (customers / circuits). Figure 4 shows the average number of customers located on each of the seven circuit branches for Oregon.

Figure 4 – Oregon Average Customers by Hypothetical Circuit Branch

	Voltage	Load Size	Customers per Circuit Branch 1	2	3	4	5	6	7
Schedule 4			4.59	4.59	4.59	18.54	18.54	18.54	876.32
Schedule 23	Secondary	0-15 kW	1.25	1.25	1.25	3.64	3.64	3.64	111.89
		15+ kW	0.26	0.26	0.26	0.76	0.76	0.76	23.21
	Primary		0.00	0.00	0.00	0.00	0.00	0.00	0.10
Schedule 28	Secondary	0-50 kW	0.04	0.04	0.04	0.14	0.14	0.14	6.96
		51-100 kW	0.04	0.04	0.04	0.12	0.12	0.12	5.85
		100+ kW	0.02	0.02	0.02	0.08	0.08	0.08	3.68
	Primary		0.00	0.00	0.00	0.00	0.00	0.00	0.09
Schedule 30	Secondary	0-300 kW	0.00	0.00	0.00	0.00	0.00	0.00	0.35
		300+ kW	0.00	0.00	0.00	0.01	0.01	0.01	0.94
	Primary		0.00	0.00	0.00	0.00	0.00	0.00	0.08
Schedule 48	Secondary	1-4 MW	0.00	0.00	0.00	0.00	0.00	0.00	0.14
		> 4 MW	-	-	-	-	-	-	-
	Primary	1-4 MW	0.00	0.00	0.00	0.00	0.00	0.00	0.09
		> 4 MW	-	-	-	-	-	-	-
Schedule 41			0.14	0.14	0.14	0.88	0.88	0.88	7.89

Load Accumulation

The kW load that a customer or class places on the system influences the size of the conductor necessary to serve the load. At each point on the circuit, the conductor must be sized to carry the entire downstream load. At the far ends of the outer branches, loads are minimal. As you move upstream closer to the substation, the load on the circuit becomes greater requiring larger conductor sizes. In the model, load can accumulate two ways. The first occurs as customers accumulate on a branch of the circuit. When enough customers, or load, accumulate it is necessary to increment up to the next wire size. Upstream from that point, customer segments increase in cost due to the increase in wire size. The second method of load accumulation is when several branches converge at a central point on the trunk of the circuit. The trunk branches must be of adequate size to carry the load of the customers on that branch plus all downstream branches.

Figure 5 shows the circuit kW loading on each of the circuit branches for Oregon. Loads are for customers located on that branch. Accumulated loads for branch 6 would be the combined loads of branches 1, 2, 3 and 6. Accumulated loads for branch 7 would be the combined loads of all branches.

Figure 5 – Oregon Circuit kW Load by Branch

	Voltage	Load Size	kW Load per Circuit Branch 1	2	3	4	5	6	7
Schedule 4			10.09	10.09	10.09	40.77	40.77	40.77	1,926.93
Schedule 23	Secondary	0-15 kW	1.51	1.51	1.51	4.41	4.41	4.41	135.44
		15+ kW	1.61	1.61	1.61	4.71	4.71	4.71	144.76
	Primary		0.01	0.01	0.01	0.02	0.02	0.02	0.65
Schedule 28	Secondary	0-50 kW	0.63	0.63	0.63	2.09	2.09	2.09	100.44
		51-100 kW	1.01	1.01	1.01	3.34	3.34	3.34	160.66
		100+ kW	1.49	1.49	1.49	4.89	4.89	4.89	235.45
	Primary		0.03	0.03	0.03	0.09	0.09	0.09	4.36
Schedule 30	Secondary	0-300 kW	0.16	0.16	0.16	0.47	0.47	0.47	45.32
		300+ kW	0.87	0.87	0.87	2.60	2.60	2.60	251.14
	Primary		0.06	0.06	0.06	0.17	0.17	0.17	16.83
Schedule 48	Secondary	1-4 MW	1.07	1.07	1.07	1.96	1.96	1.96	104.79
		> 4 MW	-	-	-	-	-	-	-
	Primary	1-4 MW	0.92	0.92	0.92	1.68	1.68	1.68	89.68
		> 4 MW	-	-	-	-	-	-	-
Schedule 41			0.87	0.87	0.87	5.34	5.34	5.34	47.96

Circuit Model Cost Assignment

Line statistics for the PacifiCorp service area show that the distribution system is predominately overhead. To calculate the cost of branch construction, miles per branch is calculated by taking the distance per circuit (total line miles / total number of circuits) and dividing it by the number of branches per circuit (7 branches, see figure 1). Next, using an assumption from distribution engineers that the typical outer branches are 25% single phase, the circuit branch length is split between single and three-phase. The total branch construction cost can then be calculated by taking the single and three-phase distances per branch and multiplying them by the one mile construction costs for poles and conductors. Costs are split between demand and commitment by assuming that the cost of constructing the branch with the smallest single-phase conductor and smallest pole is the commitment related portion and all costs above this amount are demand related. Trunk branches 6 and 7 are shown as 100% three-phase. Figure 6 shows the circuit costs per mile.

Figure 6 – Adjusted Oregon Line Costs per Mile

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 Phase - 1/0 ACSR	32,751	0.992	32,502	15,874	48,376
3 Phase - 1/0 ACSR	62,234	0.992	61,761	35,205	96,966
3 Phase - 447 AAC & 4\0 AAC	68,900	0.992	68,377	79,619	147,996
3 Phase -795 AAC & 477 AAC	71,562	0.992	71,019	134,976	205,995

Customer Circuit Costs

After calculating the cost per mile for single and three-phase construction for all of the branches, we compile the data and create a hypothetical circuit model branch cost sheet, as shown in figure 7.

Figure 7 – Oregon Hypothetical Circuit Model Branch Costs

	Pole $		Conductor $	
	Commitment	Demand	Commitment	Demand
Branches 1-5				
1 Phase - 1/0 ACSR	55,435	-	27,074	-
3 Phase - 1/0 ACSR	102,950	92,677	50,280	61,230
Total	158,385	92,677	77,354	61,230
Branch 6				
3 Phase - 447 AAC & 4\0 AAC	158,385	174,817	77,354	310,631
Branch 7				
3 Phase -795 AAC & 477 AAC	158,385	187,691	77,354	580,387

Cost Sharing Calculation

As mentioned before, one of the critical factors of cost-responsibility is the location of a customer or class on the circuit branches. Customer classes that locate on all branches share cost responsibility for all branches of the circuit including the trunk. Large industrial customers, who locate on the trunk of the circuit, share cost responsibility for only the trunk. Cost responsibility is determined by calculating the percentage of demand, or percentage of customers, by class that share a particular branch of the circuit. The total branch costs are then multiplied by the share percentage, and the branch costs are totaled by class. To calculate the total branch cost, the applicable cost of branches 6 and 7 are assigned to customers on branches 1, 2, 3, 4 and 5. Demand costs calculated in an earlier step are allocated between customer classes at this point. Figure 8 shows this calculation along with the allocation of branch costs to the individual customer classes for Oregon. Demand costs are totaled for each customer class and divided by circuit kW to get demand cost in dollars per kW.

Figure 8 – Oregon Poles and Conductors Demand Calculations, Cost Assignment

		Load	Pole Demand $ per Circuit Branch							Conductor Demand $ per Circuit Branch						
	Voltage	Size	1	2	3	4	5	6	7	1	2	3	4	5	6	7
Schedule 4			59,753	59,753	59,753	54,244	54,244	55,553	102,079	55,520	55,520	55,520	41,090	41,090	101,552	315,655
Schedule 23	Secondary	0-15 kW	8,941	8,941	8,941	5,868	5,868	6,010	7,175	8,307	8,307	8,307	4,445	4,445	10,986	22,187
		15+ kW	9,556	9,556	9,556	6,272	6,272	6,423	7,669	8,879	8,879	8,879	4,751	4,751	11,742	23,713
	Primary		43	43	43	28	28	29	35	40	40	40	21	21	53	107
Schedule 28	Secondary	0-50 kW	3,754	3,754	3,754	2,777	2,777	2,844	5,321	3,488	3,488	3,488	2,104	2,104	5,199	16,454
		51-100 kW	6,005	6,005	6,005	4,442	4,442	4,549	8,511	5,580	5,580	5,580	3,365	3,365	8,316	26,318
		100+ kW	8,801	8,801	8,801	6,510	6,510	6,667	12,473	8,177	8,177	8,177	4,932	4,932	12,188	38,570
	Primary		163	163	163	121	121	124	231	152	152	152	91	91	226	715
Schedule 30	Secondary	0-300 kW	927	927	927	624	624	640	2,401	861	861	861	473	473	1,169	7,424
		300+ kW	5,136	5,136	5,136	3,460	3,460	3,544	13,304	4,772	4,772	4,772	2,621	2,621	6,478	41,140
	Primary		344	344	344	232	232	238	892	320	320	320	176	176	434	2,758
Schedule 48	Secondary	1-4 MW	6,336	6,336	6,336	2,608	2,608	2,671	5,551	5,887	5,887	5,887	1,976	1,976	4,883	17,167
		> 4 MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Primary	1-4 MW	5,422	5,422	5,422	2,232	2,232	2,286	4,751	5,038	5,038	5,038	1,691	1,691	4,179	14,691
		> 4 MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Schedule 41			5,176	5,176	5,176	7,099	7,099	7,271	2,540	4,810	4,810	4,810	5,378	5,378	13,291	7,856

Commitment costs are calculated using a similar method. Commitment costs calculated in an earlier step are allocated to classes using percent of customers on a given branch. Commitment dollars are totaled by customer class then divided by the number of customers in the class to get commitment costs in dollars per customer. Figure 9 shows these calculations for Oregon.

Figure 9–Oregon Poles and Conductors Commitment Calculations, Cost Assignment

		Load	Pole Commitment $ per Circuit Branch							Conductor Commitment $ per Circuit Branch						
	Voltage	Size	1	2	3	4	5	6	7	1	2	3	4	5	6	7
Schedule 4			114,432	114,432	114,432	121,427	121,427	121,427	133,767	55,888	55,888	55,888	59,304	59,304	59,304	65,332
Schedule 23	Secondary	0-15 kW	31,102	31,102	31,102	23,861	23,861	23,861	17,079	15,190	15,190	15,190	11,654	11,654	11,654	8,342
		15+ kW	6,451	6,451	6,451	4,949	4,949	4,949	3,543	3,151	3,151	3,151	2,417	2,417	2,417	1,730
	Primary		27	27	27	21	21	21	15	13	13	13	10	10	10	7
Schedule 28	Secondary	0-50 kW	1,096	1,096	1,096	947	947	947	1,063	535	535	535	463	463	463	519
		51-100 kW	922	922	922	797	797	797	894	450	450	450	389	389	389	436
		100+ kW	580	580	580	501	501	501	562	283	283	283	245	245	245	275
	Primary		14	14	14	12	12	12	14	7	7	7	6	6	6	7
Schedule 30	Secondary	0-300 kW	30	30	30	23	23	23	53	15	15	15	11	11	11	26
		300+ kW	81	81	81	64	64	64	144	40	40	40	31	31	31	70
	Primary		6	6	6	5	5	5	11	3	3	3	2	2	2	6
Schedule 48	Secondary	1-4 MW	36	36	36	17	17	17	21	17	17	17	8	8	8	10
		> 4 MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Primary	1-4 MW	23	23	23	11	11	11	14	11	11	11	5	5	5	7
		> 4 MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Schedule 41			3,585	3,585	3,585	5,747	5,747	5,747	1,204	1,751	1,751	1,751	2,807	2,807	2,807	588

Large Industrial Customers

Distribution studies have shown that very large industrial customers are not placed on a circuit in the same manner as residential or smaller commercial and industrial customers. Rather the customer is located very close to a substation (the average distance in Oregon is 2/3 of a mile) and has a dedicated circuit for their exclusive use. Since they have a dedicated circuit, they do not share in the costs of other common distribution investments, but they are responsible for the entire cost of the dedicated circuit. Dividing the total cost of a 2/3 of a mile circuit by the customer's kW determines the demand cost in dollars per kW for these customers.

Summary

The final step in the circuit model is to bring the various results together in a single summary page. Figure 10 shows these results. Note that the $ are the distribution investments to serve that customer and not the price that the customer is expected to pay.

Figure 10 – Oregon Summary of Results

Pole and Conductor $ (Circuit Model)						
		Load	Demand		Commitment	
	Voltage	Size	Pole	Conduct.	Pole	Conduct.
Schedule 4			17.74	26.52	73.68	35.99
Schedule 23	Secondary	0-15 kW	27.97	36.21	119.08	58.16
		15+ kW	27.97	36.21	119.08	58.16
	Primary		27.97	36.21	119.08	58.16
Schedule 28	Secondary	0-50 kW	19.05	27.70	79.13	38.65
		51-100 kW	19.05	27.70	79.13	38.65
		100+ kW	19.05	27.70	79.13	38.65
	Primary		19.05	27.70	79.13	38.65
Schedule 30	Secondary	0-300 kW	12.41	21.27	48.87	23.87
		300+ kW	12.41	21.27	48.87	23.87
	Primary		12.41	21.27	48.87	23.87
Schedule 48	Secondary	1-4 MW	23.60	31.75	97.85	47.79
		> 4 MW	1.47	2.79		
	Primary	1-4 MW	23.60	31.75	97.85	47.79
		> 4 MW	0.63	1.19		
Schedule 41			49.18	57.63	220.84	107.86

Table 1 - Demand and Energy in Mills per kWh								
		Load	Energy $			Demand & Energy $		
	Voltage	Size	1-Year	10-Year	20-Year	1-Year	10-Year	20-Year
Schedule 4	Secondary		37.98	38.40	38.40	37.98	94.75	94.72
Schedule 23								
	Secondary	0-15 kW	37.98	38.40	38.40	37.98	94.67	94.65
	Secondary	15+ kW	37.98	38.40	38.40	37.98	92.01	91.99
	Primary		37.39	37.81	37.81	37.39	80.08	80.07
Schedule 28								
	Secondary	0-50 kW	37.98	38.40	38.40	37.98	84.84	84.82
	Secondary	51-100 kW	37.98	38.40	38.40	37.98	84.78	84.76
	Secondary	100+ kW	37.98	38.40	38.40	37.98	82.65	82.63
	Primary		37.39	37.81	37.81	37.39	78.19	78.18
Schedule 30								
	Secondary	0-300 kW	37.98	38.40	38.40	37.98	78.04	78.02
	Secondary	300+ kW	37.98	38.40	38.40	37.98	76.70	76.69
	Primary		37.39	37.81	37.81	37.39	71.27	71.25
Schedule 48								
	Secondary	1-4 MW	37.98	38.40	38.40	37.98	79.60	79.58
	Secondary	> 4 MW	37.98	38.40	38.40	37.98	65.81	65.79
	Primary	1-4 MW	37.39	37.81	37.81	37.39	77.64	77.63
	Primary	> 4 MW	37.39	37.81	37.81	37.39	61.66	61.65
	Transmission		36.41	36.82	36.82	36.41	56.86	56.85
Schedule 41			37.98	38.40	38.40	37.98	102.44	102.42
Lighting			37.98	38.40	38.40	37.98	42.84	42.84

Energy costs include both generation and transmission energy-related costs.

Table 2 - Commitment and Billing $ per Customer per Month				
	Voltage	Load Size	1-Year	10- & 20- Year
Schedule 4			14.03	39.22
Schedule 23				
	Secondary	0-15 kW	16.60	61.74
	Secondary	15+ kW	27.61	78.01
	Primary		191.35	185.89
Schedule 28				
	Secondary	0-50 kW	31.60	125.38
	Secondary	51-100 kW	32.27	134.32
	Secondary	100+ kW	70.54	179.83
	Primary		167.09	181.81
Schedule 30				
	Secondary	0-300 kW	92.84	212.24
	Secondary	300+ kW	134.40	253.88
	Primary		188.20	197.29
Schedule 48				
	Secondary	1-4 MW	742.54	869.05
	Secondary	> 4 MW	742.54	850.85
	Primary	1-4 MW	561.29	579.50
	Primary	> 4 MW	561.29	561.29
	Transmission		2,833.35	2,833.35
Schedule 41			9.55	140.43
Lighting			4.70	66.44

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 - 20-Year Marginal Cost

					23			28				30			48						
					Secondary			Secondary				Secondary			Secondary		Primary				
			Total	4	0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100+ kW	Primary	0-300 kW	300+ kW	Primary	1-4 MW	> 4 MW	1-4 MW	> 4 MW	Transmission	41	15,51,53,54
Units	Demand	Peak MW @ Input-System		1,110	90	97	0	65	103	151	3	28	157	11	71	9	60	300	312	34	1
Units	Demand	Peak MW @ Input-Distribution		1,299	96	102	0	68	109	159	3	29	163	11	71	9	60	296	-	42	0
Units	Demand	Peak MW @ Input-Transformer		3,907	825	536	-	232	454	534	-	70	320	-	125	30	-	-	-	266	16
Units	Energy	Annual MWh @ Input		6,024,472	575,840	616,346	3,035	417,460	673,641	1,019,031	18,517	192,198	1,097,071	80,700	515,118	75,844	429,139	2,499,837	2,629,644	243,781	22,175
Units	Customer	Average		557,684	72,880	15,117	64	4,450	3,743	2,354	59	213	580	46	89	3	54	44	10	4,346	7,545
Units	Customer	Annual - Metered		557,684	72,880	15,117	64	4,450	3,743	2,354	59	213	580	46	89	3	54	44	10	7,808	96
$/Unit	Demand	Generation ($/System Peak kW)		138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	138.62	-
$/Unit	Demand	Transmission ($/System Peak kW)		24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	-
$/Unit	Demand	Dist-Poles ($/Dist. kW)		26.61	41.96	41.96	41.96	28.58	28.58	28.58	28.58	18.61	18.61	18.61	35.39	2.20	35.39	0.94	-	73.77	41.96
$/Unit	Demand	Dist-Cond ($/Dist. kW)		39.78	54.31	54.31	54.31	41.55	41.55	41.55	41.55	31.91	31.91	31.91	47.63	4.19	47.63	1.79	-	86.44	54.31
$/Unit	Demand	Dist-Substation ($/Dist. kW)		21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	-	21.07	-
$/Unit	Demand	Dist-Transformers ($/Xfmr kW)		4.99	4.99	4.99	-	4.99	4.99	4.99	-	4.99	4.99	-	4.99	4.99	-	-	-	4.99	4.99
$/Unit	Energy	Generation Energy @ Input ($/kWh)		0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
$/Unit	Energy	Transmission Energy @ Input ($/kWh)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
$/Unit	Customer	Dist-Poles ($/Customer)		110.52	178.61	178.61	178.61	118.70	118.70	118.70	118.70	73.29	73.29	73.29	146.77	-	146.77	-	-	331.25	178.61
$/Unit	Customer	Dist-Conductor ($/Customer)		53.98	87.23	87.23	87.23	57.97	57.97	57.97	57.97	35.80	35.80	35.80	71.68	-	71.68	-	-	161.78	87.23
$/Unit	Customer	Dist-Transformers ($/Customer)		137.75	275.89	338.86	-	948.63	1,047.92	1,134.77	-	1,323.80	1,324.68	-	1,299.77	1,299.77	-	-	-	1,077.56	474.97
$/Unit	Customer	Dist-Service Drop ($/Customer)		97.15	134.47	255.71	-	263.87	272.19	548.26	-	561.55	1,060.26	-	3,689.30	3,689.30	-	-	-	-	-
$/Unit	Customer	Meters ($/Customer)		24.01	25.44	36.38	1,925.55	35.82	35.52	218.70	1,925.55	219.66	219.75	1,925.55	411.16	411.16	1,925.55	1,925.55	29,190.18	36.14	25.44
$/Unit	Customer	Billing & Collections ($/Customer)		21.96	24.57	24.57	24.57	26.33	26.33	26.33	26.33	26.33	26.33	26.33	213.48	213.48	213.48	213.48	213.48	30.61	20.92
$/Unit	Customer	Uncollectables ($/Customer)		14.37	4.23	4.23	4.23	40.66	40.66	40.66	40.66	280.81	280.81	280.81	4,338.82	4,338.82	4,338.82	4,338.82	4,338.82	35.30	-
$/Unit	Customer	Customer Service / Other ($/Customer)		10.89	10.47	10.47	10.47	12.56	12.56	12.56	12.56	25.69	25.69	25.69	257.67	257.67	257.67	257.67	257.67	12.50	10.04
$000	Demand	Generation	360,535	153,831	12,445	13,511	57	9,004	14,232	20,870	372	3,898	21,744	1,499	9,862	1,302	8,339	41,613	43,212	4,746	-
$000	Demand	Transmission	64,058	27,332	2,211	2,401	10	1,600	2,529	3,708	66	693	3,863	266	1,752	231	1,482	7,394	7,678	843	-
$000	Demand	Dist-Poles	64,369	34,566	4,016	4,292	19	1,939	3,101	4,545	83	549	3,041	201	2,518	19	2,127	278	-	3,069	6
$000	Demand	Dist-Conductor	93,442	51,685	5,199	5,556	25	2,819	4,509	6,609	121	941	5,214	345	3,389	37	2,862	529	-	3,596	7
$000	Demand	Dist-Substations	53,053	27,377	2,017	2,156	10	1,430	2,287	3,352	61	621	3,443	228	1,499	186	1,266	6,243	-	877	-
$000	Demand	Dist-Transformers	36,472	19,480	4,114	2,674	-	1,156	2,265	2,664	-	350	1,594	-	626	148	-	-	-	1,324	78
$000	Demand	Total Demand	671,930	314,271	30,002	30,590	121	17,948	28,923	41,747	703	7,052	38,899	2,539	19,646	1,924	16,075	56,057	50,889	14,454	91
$000	Energy	Generation	609,468	214,296	20,483	21,924	108	14,849	23,962	36,248	659	6,837	39,024	2,871	18,323	2,698	15,265	88,922	93,539	8,672	789
$000	Energy	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
$000	Energy	Total Energy	609,468	214,296	20,483	21,924	108	14,849	23,962	36,248	659	6,837	39,024	2,871	18,323	2,698	15,265	88,922	93,539	8,672	789
$000	Customer	Dist-Poles	81,289	61,633	13,017	2,700	11	528	444	279	7	16	43	3	13	-	8	-	-	2,586	-
$000	Customer	Dist-Conductor	39,701	30,101	6,358	1,319	6	258	217	136	3	8	21	2	6	-	4	-	-	1,263	-
$000	Customer	Dist-Transformers	122,450	76,822	20,107	5,123	-	4,221	3,922	2,671	-	281	769	-	116	4	-	-	-	8,414	-
$000	Customer	Dist-Service Drop	72,403	54,179	9,800	3,866	-	1,174	1,019	1,291	-	119	615	-	328	11	-	-	-	-	-
$000	Customer	Meters	17,903	13,389	1,854	550	123	159	133	515	114	47	128	89	37	1	104	85	292	282	2
$000	Customer	Billing & Collections	15,043	12,245	1,791	371	2	117	99	62	2	6	15	1	19	1	11	9	2	133	158
$000	Customer	Uncollectables	10,076	8,016	308	64	0	181	152	96	2	60	163	13	386	13	233	192	43	153	-
$000	Customer	Customer Service / Other	7,330	6,071	763	158	1	56	47	30	1	5	15	1	23	1	14	11	3	54	76
$000	Customer	Total Customer (Commitment & Billing)	366,196	262,457	53,998	14,151	143	6,695	6,033	5,080	129	542	1,768	109	928	31	374	298	340	12,886	236
$000	Total	Generation	970,003	368,127	32,928	35,435	165	23,853	38,194	57,117	1,031	10,735	60,768	4,369	28,185	4,000	23,604	130,535	136,751	13,417	789
$000	Total	Transmission	64,058	27,332	2,211	2,401	10	1,600	2,529	3,708	66	693	3,863	266	1,752	231	1,482	7,394	7,678	843	-
$000	Total	Distribution	563,180	355,844	64,627	27,685	70	13,526	17,765	21,547	276	2,885	14,739	779	8,495	406	6,266	7,050	-	21,128	91
$000	Total	Customer Billing	25,119	20,261	2,099	435	2	298	251	158	4	65	178	14	405	14	245	201	46	286	158
$000	Total	Customer Metering	17,903	13,389	1,854	550	123	159	133	515	114	47	128	89	37	1	104	85	292	282	2
$000	Total	Customer Service / Other	7,330	6,071	763	158	1	56	47	30	1	5	15	1	23	1	14	11	3	54	76
$000	Total	Total Revenue	1,647,595	791,024	104,482	66,664	371	39,493	58,919	83,075	1,491	14,430	79,691	5,518	38,896	4,653	31,714	145,277	144,768	36,012	1,116

Table 4 - Marginal Generation Costs in Nominal Dollars		
	Energy Only ($ per MWh)	Capacity Only ($ per kW)
2027 (1 Year)	35.18	168.33
2027 - 2031 (5 Year, Short Run)	35.46	147.13
2027 - 2036 (10 Year, Medium Run)	35.57	138.75
2027 - 2046 (20 Year, Long Run)	35.57	138.62

Table 5 - Transmission Investment and Associated Expenses	
Growth Related Investments - (2026 to 2030 in $000s)	2,077,118
System Growth MW from 2026 to 2030	7,399
Marginal Investment ($ per kW)	280.73
Demand $ per kW	280.73
Demand $ per kW Annualized	18.25
Demand $ per kW A&G	3.42
Demand $ per kW O&M	2.95
Demand $ per kW Annualized Total	24.63
Energy $ per kWh	-
Energy $ per kWh Annualized	-
Energy $ per kWh A&G	-
Energy $ per kWh O&M	-
Energy $ per kWh Annualized Total	-

Table 6 - Marginal Distribution and Billing Costs

		23			28				30			48						
		Secondary			Secondary				Secondary			Secondary		Primary				
	4	0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100+ kW	Primary	0-300 kW	300+ kW	Primary	1-4 MW	> 4 MW	1-4 MW	> 4 MW	Transmission	41	15,51,53,54
Demand Costs ($/kW)																		
Dist-Poles	17.74	27.97	27.97	27.97	19.05	19.05	19.05	19.05	12.41	12.41	12.41	23.60	1.47	23.60	0.63	-	49.18	-
Dist-Conductors	26.52	36.21	36.21	36.21	27.70	27.70	27.70	27.70	21.27	21.27	21.27	31.75	2.79	31.75	1.19	-	57.63	-
Dist-Substation	14.05	14.05	14.05	14.05	14.05	14.05	14.05	14.05	14.05	14.05	14.05	14.05	14.05	14.05	14.05	-	14.05	14.05
Dist. O&M @ 49.99% of Investment	29.15	39.11	39.11	39.11	30.40	30.40	30.40	30.40	23.86	23.86	23.86	34.69	9.15	34.69	7.93	-	60.42	7.02
Total $/Dist. kW	87.46	117.34	117.34	117.34	91.20	91.20	91.20	91.20	71.59	71.59	71.59	104.09	27.46	104.09	23.80	-	181.28	21.07
Dist-Transformers	3.32	3.32	3.32	-	3.32	3.32	3.32	-	3.32	3.32	-	3.32	3.32	-	-	-	3.32	3.32
Dist. O&M @ 49.99% of Investment	1.66	1.66	1.66	-	1.66	1.66	1.66	-	1.66	1.66	-	1.66	1.66	-	-	-	1.66	1.66
Total $/Transformer kW	4.99	4.99	4.99	-	4.99	4.99	4.99	-	4.99	4.99	-	4.99	4.99	-	-	-	4.99	4.99
Customer Costs ($/Customer)																		
Commitment																		
Dist-Poles	73.68	119.08	119.08	119.08	79.13	79.13	79.13	79.13	48.87	48.87	48.87	97.85	-	97.85	-	-	220.84	-
Dist-Conductors	35.99	58.16	58.16	58.16	38.65	38.65	38.65	38.65	23.87	23.87	23.87	47.79	-	47.79	-	-	107.86	-
Dist-Transformers	91.84	183.93	225.92	-	632.45	698.64	756.55	-	882.57	883.16	-	866.55	-	866.55	-	-	718.41	316.66
Dist. O&M @ 49.99% of Investment	100.74	180.56	201.55	88.61	375.06	408.16	437.11	58.88	477.59	477.88	36.36	506.03	-	506.03	-	-	523.48	158.31
Total Commitment	302.24	541.73	604.70	265.84	1,125.29	1,224.58	1,311.44	176.67	1,432.89	1,433.78	109.09	1,518.23	-	1,518.23	-	-	1,570.60	474.97
Monthly Commitment	25.19	45.14	50.39	22.15	93.77	102.05	109.29	14.72	119.41	119.48	9.09	126.52	-	126.52	-	-	130.88	39.58
Billing																		
Dist-Service Drop	64.77	89.65	170.48	-	175.92	181.47	365.52	-	374.38	706.87	-	2,459.64	-	2,459.64	-	-	-	-
Dist. O&M @ 49.99% of Investment	32.38	44.82	85.23	-	87.95	90.72	182.74	-	187.17	353.39	-	1,229.65	-	1,229.65	-	-	-	-
Meter	19.15	20.29	29.01	1,535.55	28.57	28.33	174.41	1,535.55	175.17	175.25	1,535.55	327.88	327.88	1,535.55	1,535.55	23,277.94	28.82	20.29
Meter O&M @ 25.40% of Investment	4.86	5.15	7.37	390.01	7.26	7.19	44.30	390.01	44.49	44.51	390.01	83.28	83.28	390.01	390.01	5,912.23	7.32	5.15
Billing & Collections	21.96	24.57	24.57	24.57	26.33	26.33	26.33	26.33	26.33	26.33	26.33	213.48	213.48	213.48	213.48	213.48	30.61	20.92
Uncollectables	14.37	4.23	4.23	4.23	40.66	40.66	40.66	40.66	280.81	280.81	280.81	4,338.82	4,338.82	4,338.82	4,338.82	4,338.82	35.30	-
Customer Service / Other	10.89	10.47	10.47	10.47	12.56	12.56	12.56	12.56	25.69	25.69	25.69	257.67	257.67	257.67	257.67	257.67	12.50	10.04
Total Billing	168.38	199.18	331.36	1,964.83	379.24	387.27	846.52	2,005.11	1,114.04	1,612.84	2,258.38	8,910.42	5,221.13	10,424.82	6,735.52	34,000.14	114.55	56.41
Monthly Billing	14.03	16.60	27.61	163.74	31.60	32.27	70.54	167.09	92.84	134.40	188.20	742.54	435.09	868.73	561.29	2,833.35	9.55	4.70
Total Customer (Commitment & Billing)	470.62	740.91	936.06	2,230.67	1,504.54	1,611.85	2,157.95	2,181.77	2,546.93	3,046.61	2,367.47	10,428.65	5,221.13	11,943.04	6,735.52	34,000.14	1,685.15	531.38
Monthly Customer (Commitment & Billing)	39.22	61.74	78.01	185.89	125.38	134.32	179.83	181.81	212.24	253.88	197.29	869.05	435.09	995.25	561.29	2,833.35	140.43	44.28

Table 7 - 20 Year Demand Costs Divided by Billing kW

			23			28				30			48						
			Secondary			Secondary				Secondary			Secondary		Primary				
	Total	4	0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100+ kW	Primary	0-300 kW	300+ kW	Primary	1-4 MW	> 4 MW	1-4 MW	> 4 MW	Transmission	41	15,51,53,54
Generation	360,535	153,831	12,445	13,511	57	9,004	14,232	20,870	372	3,898	21,744	1,499	9,862	1,302	8,339	41,613	43,212	4,746	-
Transmission	64,058	27,332	2,211	2,401	10	1,600	2,529	3,708	66	693	3,863	266	1,752	231	1,482	7,394	7,678	843	-
Dist-Poles, Wire, Sub	210,864	113,628	11,232	12,004	53	6,188	9,898	14,506	265	2,111	11,697	774	7,406	243	6,255	7,050	-	7,541	13
Dist-Transformers	36,472	19,480	4,114	2,674	-	1,156	2,265	2,664	-	350	1,594	-	626	148	-	-	-	1,324	78
Average Billing kW @ Sales	9,504,806	5,376,556	760,738	494,495	1,013	213,828	418,814	492,614	19,086	64,686	294,749	18,828	115,690	27,339	112,206	448,117	389,293	244,873	11,880
Generation ($/kW)		28.61	2.31	2.51	0.01	1.67	2.65	3.88	0.07	0.73	4.04	0.28	1.83	0.24	1.55	7.74	8.04	0.88	-
Transmission ($/kW)		5.08	0.41	0.45	0.00	0.30	0.47	0.69	0.01	0.13	0.72	0.05	0.33	0.04	0.28	1.38	1.43	0.16	-
Dist-Poles, Wire, Sub ($/kW)		21.13	2.09	2.23	0.01	1.15	1.84	2.70	0.05	0.39	2.18	0.14	1.38	0.05	1.16	1.31	-	1.40	0.00
Dist-Transformers ($/kW)		3.62	0.77	0.50	-	0.22	0.42	0.50	-	0.07	0.30	-	0.12	0.03	-	-	-	0.25	0.01
Total Demand Related		58.45	5.58	5.69	0.02	3.34	5.38	7.76	0.13	1.31	7.23	0.47	3.65	0.36	2.99	10.43	9.47	2.69	0.02
Monthly Demand Related		4.87	0.47	0.47	0.00	0.28	0.45	0.65	0.01	0.11	0.60	0.04	0.30	0.03	0.25	0.87	0.79	0.22	0.00

Table 8 - Marginal Cost Percentages				
	$000	Mills per kWh	% of Total	
Demand Related				
Generation	360,535	22.51	22%	
Transmission	64,058	4.00	4%	
Dist. Poles, Cond., Subst.	210,864	13.16	13%	
Dist. Transformers	36,472	2.28	2%	
Total	671,930	41.95	41%	
Energy Related				
Generation	609,468	38.05	37%	
Transmission	-	-	0%	
Total	609,468	38.05	37%	
Commitment & Billing				
Commitment	243,441	15.20	15%	
Billing	122,756	7.66	7%	
Total	366,196	22.86	22%	
Total	1,647,595	102.86	100%	
MWh @ Sales				16,018,955

10-Year Marginal Cost, by Schedule, Voltage, and Load Size

					23			28				30			48						
					Secondary			Secondary				Secondary			Secondary		Primary				
			Total	4	0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100+ kW	Primary	0-300 kW	300+ kW	Primary	1-4 MW	> 4 MW	1-4 MW	> 4 MW	Transmission	41	15,51,53,54
Units	Demand	Peak MW @ Input-System		1,110	90	97	0	65	103	151	3	28	157	11	71	9	60	300	312	34	1
Units	Demand	Peak MW @ Input-Distribution		1,299	96	102	0	68	109	159	3	29	163	11	71	9	60	296	-	42	0
Units	Demand	Peak MW @ Input-Transformer		3,907	825	536	-	232	454	534	-	70	320	-	125	30	-	-	-	266	16
Units	Energy	Annual MWh @ Input		6,024,472	575,840	616,346	3,035	417,460	673,641	1,019,031	18,517	192,198	1,097,071	80,700	515,118	75,844	429,139	2,499,837	2,629,644	243,781	22,175
Units	Customer	Average		557,684	72,880	15,117	64	4,450	3,743	2,354	59	213	580	46	89	3	54	44	10	4,346	7,545
Units	Customer	Annual - Metered		557,684	72,880	15,117	64	4,450	3,743	2,354	59	213	580	46	89	3	54	44	10	7,808	96
$/Unit	Demand	Generation ($/System Peak kW)		138.75	138.75	138.75	138.75	138.75	138.75	138.75	138.75	138.75	138.75	138.75	138.75	138.75	138.75	138.75	138.75	138.75	-
$/Unit	Demand	Transmission ($/System Peak kW)		24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	-
$/Unit	Demand	Dist-Poles ($/Dist. kW)		26.61	41.96	41.96	41.96	28.58	28.58	28.58	28.58	18.61	18.61	18.61	35.39	2.20	35.39	0.94	-	73.77	41.96
$/Unit	Demand	Dist-Cond ($/Dist. kW)		39.78	54.31	54.31	54.31	41.55	41.55	41.55	41.55	31.91	31.91	31.91	47.63	4.19	47.63	1.79	-	86.44	54.31
$/Unit	Demand	Dist-Substation ($/Dist. kW)		21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	21.07	-	21.07	-
$/Unit	Demand	Dist-Transformers ($/Xfmr kW)		4.99	4.99	4.99	-	4.99	4.99	4.99	-	4.99	4.99	-	4.99	4.99	-	-	-	4.99	4.99
$/Unit	Energy	Generation Energy @ Input ($/kWh)		0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
$/Unit	Customer	Dist-Poles ($/Customer)		110.52	178.61	178.61	178.61	118.70	118.70	118.70	118.70	73.29	73.29	73.29	146.77	-	146.77	-	-	331.25	178.61
$/Unit	Customer	Dist-Conductor ($/Customer)		53.98	87.23	87.23	87.23	57.97	57.97	57.97	57.97	35.80	35.80	35.80	71.68	-	71.68	-	-	161.78	87.23
$/Unit	Customer	Dist-Transformers ($/Customer)		137.75	275.89	338.86	-	948.63	1,047.92	1,134.77	-	1,323.80	1,324.68	-	1,299.77	1,299.77	-	-	-	1,077.56	474.97
$/Unit	Customer	Dist-Service Drop ($/Customer)		97.15	134.47	255.71	-	263.87	272.19	548.26	-	374.38	1,060.26	-	3,689.30	3,689.30	-	-	-	-	-
$/Unit	Customer	Meters ($/Customer)		24.01	25.44	36.38	1,925.55	35.82	35.52	218.70	1,925.55	219.66	219.75	1,925.55	411.16	411.16	1,925.55	1,925.55	29,190.18	36.14	25.44
$/Unit	Customer	Billing & Collections ($/Customer)		21.96	24.57	24.57	24.57	26.33	26.33	26.33	26.33	26.33	26.33	26.33	213.48	213.48	213.48	213.48	213.48	30.61	20.92
$/Unit	Customer	Uncollectables ($/Customer)		14.37	4.23	4.23	4.23	40.66	40.66	40.66	40.66	280.81	280.81	280.81	4,338.82	4,338.82	4,338.82	4,338.82	4,338.82	35.30	-
$/Unit	Customer	Customer Service / Other ($/Customer)		10.89	10.47	10.47	10.47	12.56	12.56	12.56	12.56	25.69	25.69	25.69	257.67	257.67	257.67	257.67	257.67	12.50	10.04
$000	Demand	Generation	360,864	153,971	12,456	13,523	57	9,012	14,245	20,889	372	3,902	21,764	1,500	9,871	1,303	8,346	41,651	43,251	4,750	-
$000	Demand	Transmission	64,058	27,332	2,211	2,401	10	1,600	2,529	3,708	66	693	3,863	266	1,752	231	1,482	7,394	7,678	843	-
$000	Demand	Dist-Poles	64,369	34,566	4,016	4,292	19	1,939	3,101	4,545	83	549	3,041	201	2,518	19	2,127	278	-	3,069	6
$000	Demand	Dist-Conductor	93,442	51,685	5,199	5,556	25	2,819	4,509	6,609	121	941	5,214	345	3,389	37	2,862	529	-	3,596	7
$000	Demand	Dist-Substations	53,053	27,377	2,017	2,156	10	1,430	2,287	3,352	61	621	3,443	228	1,499	186	1,266	6,243	-	877	-
$000	Demand	Dist-Transformers	36,472	19,480	4,114	2,674	-	1,156	2,265	2,664	-	350	1,594	-	626	148	-	-	-	1,324	78
$000	Demand	Total Demand	672,259	314,411	30,013	30,602	121	17,956	28,936	41,766	704	7,056	38,919	2,540	19,655	1,925	16,083	56,095	50,929	14,458	91
$000	Energy	Generation	609,439	214,286	20,482	21,923	108	14,849	23,961	36,246	659	6,836	39,022	2,870	18,322	2,698	15,264	88,917	93,535	8,671	789
$000	Energy	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
$000	Energy	Total Energy	609,439	214,286	20,482	21,923	108	14,849	23,961	36,246	659	6,836	39,022	2,870	18,322	2,698	15,264	88,917	93,535	8,671	789
$000	Customer	Dist-Poles	81,289	61,633	13,017	2,700	11	528	444	279	7	16	43	3	13	-	8	-	-	2,586	-
$000	Customer	Dist-Conductor	39,701	30,101	6,358	1,319	6	258	217	136	3	8	21	2	6	-	4	-	-	1,263	-
$000	Customer	Dist-Transformers	122,450	76,822	20,107	5,123	-	4,221	3,922	2,671	-	281	769	-	116	4	-	-	-	8,414	-
$000	Customer	Dist-Service Drop	72,363	54,179	9,800	3,866	-	1,174	1,019	1,291	-	80	615	-	328	11	-	-	-	-	-
$000	Customer	Meters	17,903	13,389	1,854	550	123	159	133	515	114	47	128	89	37	1	104	85	292	282	2
$000	Customer	Billing & Collections	15,043	12,245	1,791	371	2	117	99	62	2	6	15	1	19	1	11	9	2	133	158
$000	Customer	Uncollectables	10,076	8,016	308	64	0	181	152	96	2	60	163	13	386	13	233	192	43	153	-
$000	Customer	Customer Service / Other	7,330	6,071	763	158	1	56	47	30	1	5	15	1	23	1	14	11	3	54	76
$000	Customer	Total Customer (Commitment & Billing)	366,157	262,457	53,998	14,151	143	6,695	6,033	5,080	129	502	1,768	109	928	31	374	298	340	12,886	236
$000	Total	Total Revenue	1,647,855	791,154	104,493	66,676	371	39,500	58,930	83,092	1,491	14,394	79,709	5,520	38,905	4,654	31,721	145,310	144,803	36,016	1,116

5-Year Marginal Cost, by Schedule, Voltage, and Load Size

					23			28				30			48						
					Secondary			Secondary				Secondary			Secondary		Primary				
			Total	4	0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100+ kW	Primary	0-300 kW	300+ kW	Primary	1-4 MW	> 4 MW	1-4 MW	> 4 MW	Transmission	41	15,51,53,54
Units	Demand	Peak MW @ Input-System		1,110	90	97	0	65	103	151	3	28	157	11	71	9	60	300	312	34	1
Units	Energy	Annual MWh @ Input		6,024,472	575,840	616,346	3,035	417,460	673,641	1,019,031	18,517	192,198	1,097,071	80,700	515,118	75,844	429,139	2,499,837	2,629,644	243,781	22,175
Units	Customer	Average		557,684	72,880	15,117	64	4,450	3,743	2,354	59	213	580	46	89	3	54	44	10	4,346	7,545
Units	Customer	Annual - Metered		557,684	72,880	15,117	64	4,450	3,743	2,354	59	213	580	46	89	3	54	44	10	7,808	96
$/Unit	Demand	Generation ($/System Peak kW)		147.13	147.13	147.13	147.13	147.13	147.13	147.13	147.13	147.13	147.13	147.13	147.13	147.13	147.13	147.13	147.13	147.13	-
$/Unit	Energy	Generation Energy @ Input ($/kWh)		0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
$/Unit	Customer	Dist-Service Drop ($/Customer)		97.15	134.47	255.71	-	263.87	272.19	548.26	-	561.55	1,060.26	-	3,689.30	3,689.30	-	-	-	-	-
$/Unit	Customer	Meters ($/Customer)		24.01	25.44	36.38	1,925.55	35.82	35.52	218.70	1,925.55	219.66	219.75	1,925.55	411.16	411.16	1,925.55	1,925.55	29,190.18	36.14	25.44
$/Unit	Customer	Billing & Collections ($/Customer)		21.96	24.57	24.57	24.57	26.33	26.33	26.33	26.33	26.33	26.33	26.33	213.48	213.48	213.48	213.48	213.48	30.61	20.92
$/Unit	Customer	Uncollectables ($/Customer)		14.37	4.23	4.23	4.23	40.66	40.66	40.66	40.66	280.81	280.81	280.81	4,338.82	4,338.82	4,338.82	4,338.82	4,338.82	35.30	-
$/Unit	Customer	Customer Service / Other ($/Customer)		10.89	10.47	10.47	10.47	12.56	12.56	12.56	12.56	25.69	25.69	25.69	257.67	257.67	257.67	257.67	257.67	12.50	10.04
$000	Demand	Total Demand	382,678	163,278	13,209	14,341	61	9,557	15,106	22,151	395	4,138	23,080	1,591	10,467	1,382	8,851	44,169	45,865	5,037	-
$000	Energy	Total Energy	607,528	213,614	20,418	21,854	108	14,802	23,886	36,133	657	6,815	38,900	2,861	18,265	2,689	15,216	88,639	93,241	8,644	786
$000	Customer	Total Customer (Billing)	122,756	93,901	14,516	5,009	126	1,688	1,450	1,993	118	237	936	104	793	27	362	298	340	623	236
$000	Total	Total Revenue	1,112,962	470,793	48,144	41,204	294	26,047	40,441	60,277	1,170	11,190	62,915	4,556	29,525	4,098	24,430	133,105	139,447	14,304	1,022

1-Year Marginal Cost, by Schedule, Voltage, and Load Size

					23			28				30			48						
					Secondary			Secondary				Secondary			Secondary		Primary				
			Total	4	0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100+ kW	Primary	0-300 kW	300+ kW	Primary	1-4 MW	> 4 MW	1-4 MW	> 4 MW	Transmission	41	15,51,53,54
Units	Energy	Annual MWh @ Input		6,024,472	575,840	616,346	3,035	417,460	673,641	1,019,031	18,517	192,198	1,097,071	80,700	515,118	75,844	429,139	2,499,837	2,629,644	243,781	22,175
Units	Customer	Average		557,684	72,880	15,117	64	4,450	3,743	2,354	59	213	580	46	89	3	54	44	10	4,346	7,545
Units	Customer	Annual - Metered		557,684	72,880	15,117	64	4,450	3,743	2,354	59	213	580	46	89	3	54	44	10	7,808	96
$/Unit	Energy	Generation Energy @ Input ($/kWh)		0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
$/Unit	Customer	Dist-Service Drop ($/Customer)		97.15	134.47	255.71	-	263.87	272.19	548.26	-	561.55	1,060.26	-	3,689.30	3,689.30	-	-	-	-	-
$/Unit	Customer	Meters ($/Customer)		24.01	25.44	36.38	1,925.55	35.82	35.52	174.41	1,925.55	219.66	219.75	1,925.55	411.16	411.16	1,925.55	1,925.55	29,190.18	36.14	25.44
$/Unit	Customer	Billing & Collections ($/Customer)		21.96	24.57	24.57	24.57	26.33	26.33	26.33	26.33	26.33	26.33	26.33	213.48	213.48	213.48	213.48	213.48	30.61	20.92
$/Unit	Customer	Uncollectables ($/Customer)		14.37	4.23	4.23	4.23	40.66	40.66	40.66	40.66	280.81	280.81	280.81	4,338.82	4,338.82	4,338.82	4,338.82	4,338.82	35.30	-
$/Unit	Customer	Customer Service / Other ($/Customer)		10.89	10.47	10.47	10.47	12.56	12.56	12.56	12.56	25.69	25.69	25.69	257.67	257.67	257.67	257.67	257.67	12.50	10.04
$000	Energy	Total Energy	602,697	211,916	20,256	21,680	107	14,685	23,696	35,845	651	6,761	38,590	2,839	18,120	2,668	15,095	87,934	92,500	8,575	780
$000	Customer	Total Customer (Billing)	122,651	93,901	14,516	5,009	126	1,688	1,450	1,888	118	237	936	104	793	27	362	298	340	623	236
$000	Total	Total Revenue	725,349	305,816	34,772	26,690	232	16,372	25,145	37,734	770	6,998	39,526	2,943	18,912	2,695	15,458	88,232	92,840	9,198	1,016

Generation Demand and Energy

Marginal Costs, in 2027 $

Years	Net Capacity $ per kw-yr	Energy Resource 2027 $ per MWh	Capacity Contribution of Energy	$ per kW Capacity Credit	$ per MWh
1	168.33	37.41	0.12	(2.24)	35.18
5	147.13	37.41	0.12	(1.96)	35.46
10	138.75	37.41	0.12	(1.85)	35.57
20	138.62	37.41	0.12	(1.84)	35.57

20-Year Average Annual Inflation	Weighted Cost of Capital
2.2%	7.56%

Lithium-Ion Battery, Central Oregon, 200 MW, 4hr, in 2028 $

Capacity Contribution	Commercial Operation Date Year	Years of Life
73%	2028	20

Solar, Central Oregon, Utility Scale (No PTC) in 2030 $

Capacity Factor	Commercial Operation Date Year	Years of Life
31%	2030	25

Year Number	Year	$ per kw-yr Annualized Fixed Cost	Energy Benefit of Storage	Net Capacity Cost
1	2028	126.31	0.72	172.00
2	2029	129.07	2.95	172.72
3	2030	131.88	26.61	144.17
4	2031	134.76	27.89	146.35
5	2032	137.69	34.72	141.03
6	2033	140.70	37.95	140.71
7	2034	143.76	37.04	146.16
8	2035	146.90	33.65	155.10
9	2036	150.10	32.77	160.68
10	2037	153.37	37.24	159.05
11	2038	156.72	35.92	165.43
12	2039	160.13	40.91	163.27
13	2040	163.62	24.02	191.19
14	2041	167.19	26.75	192.34
15	2042	170.83	27.55	196.23
16	2043	174.56	28.49	200.05
17	2044	178.36	31.92	200.56
18	2045	182.25	30.52	207.80
19	2046	186.23	31.19	212.33
20	2047	190.29	31.87	216.96

Annualized Fixed Cost and Energy Benefit of Storage per PacifiCorp's October 2025 energy efficiency utility data submission in docket UM 1893 that was adopted by the Commission in Order 25-500.

Year Number	Year	$ per kw-yr Annualized Fixed Cost	$ per MWh Cost to Charge Battery
1	2030	108.03	39.92
2	2031	110.39	40.79
3	2032	112.80	41.67
4	2033	115.26	42.58
5	2034	117.77	43.51
6	2035	120.34	44.46
7	2036	122.96	45.43
8	2037	125.64	46.42
9	2038	128.38	47.43
10	2039	131.18	48.47
11	2040	134.04	49.52
12	2041	136.96	50.60
13	2042	139.94	51.70
14	2043	142.99	52.83
15	2044	146.11	53.98
16	2045	149.30	55.16
17	2046	152.55	56.36
18	2047	155.88	57.59
19	2048	159.28	58.85
20	2049	162.75	60.13
21	2050	166.30	61.44
22	2051	169.92	62.78
23	2052	173.63	64.15
24	2053	177.41	65.55
25	2054	181.28	66.98

Annualized Fixed Cost per PacifiCorp's October 2025 energy efficiency utility data submission in docket UM 1893 that was adopted by the Commission in Order 25-500.

Transmission Investment and OMAG Expenses						
	2026-2030	2026	2027	2028	2029	2030
Bulk Power Lines (grid) $000 Forecast		-	-	-	-	-
Growth Related Major Projects (local) $000 Forecast		120,924	166,408	704,792	92,845	992,148
Demand Growth Related Investment $000	2,077,118	120,924	166,408	704,792	92,845	992,148
Energy Growth Related Investment $000	-	-	-	-	-	-
MW Capacity per Investments	7,399					
Demand $ per kW	280.73					
Demand $ per kW Annualized	18.25					
Demand $ per kW A&G	3.42					
Demand $ per kW O&M	2.95					
Demand $ per kW Annualized Total	24.63					
Energy $ per kWh	-					
Energy $ per kWh Annualized	-					
Energy $ per kWh A&G	-					
Energy $ per kWh O&M	-					
Energy $ per kWh Annualized Total	-					

Distribution Substation Investment	
$ per kW	379.11
MW Distribution Peak	2,326
MW Installed Capacity	4,979
Adjusted $ per kW	177.11
Adjusted $ per kW Annualized	14.05

Distribution Substation Projects

In-Service Year	Project	State	Capacity Increase (MVA)	Installed $000 Cost
2026	Banfield	Oregon	33	9,967
2026	Bond Street	Oregon	33	12,584
2026	China Hat	Oregon	33	5,592
2026	Tieton	Washington	16	8,115
2026	Mallory	Oregon	10	1,229
2026	Yew Ave	Oregon	25	11,451
2027	Ahtanum	Washington	30	15,036
2027	Butler	Oregon	33	12,001
2027	King Way	Oregon	33	22,894
2027	Klamath Falls	Oregon	93	11,940
2027	Rickreall	Oregon	33	11,386
2027	Wake Robin Ave	Oregon	33	14,854
2028	Culver	Oregon	13	6,604
2028	Line 30 & 65	Oregon	26	603
2029	Lebanon	Oregon	13	8,494
2029	Madras	Oregon	10	2,156
2030	Shastina	California	26	15,157

Pole and Conductor $ (Distribution Circuit Model)						
		Load	Demand		Commitment	
	Voltage	Size	Pole	Conduct.	Pole	Conduct.
Schedule 4			17.74	26.52	73.68	35.99
Schedule 23	Secondary	0-15 kW	27.97	36.21	119.08	58.16
		15+ kW	27.97	36.21	119.08	58.16
	Primary		27.97	36.21	119.08	58.16
Schedule 28	Secondary	0-50 kW	19.05	27.70	79.13	38.65
		51-100 kW	19.05	27.70	79.13	38.65
		100+ kW	19.05	27.70	79.13	38.65
	Primary		19.05	27.70	79.13	38.65
Schedule 30	Secondary	0-300 kW	12.41	21.27	48.87	23.87
		300+ kW	12.41	21.27	48.87	23.87
	Primary		12.41	21.27	48.87	23.87
Schedule 48	Secondary	1-4 MW	23.60	31.75	97.85	47.79
		> 4 MW	1.47	2.79		
	Primary	1-4 MW	23.60	31.75	97.85	47.79
		> 4 MW	0.63	1.19		
Schedule 41			49.18	57.63	220.84	107.86

Pole and Conductor $ per Circuit Branch (Distribution Circuit Model)

			Percentage Distribution by Branch							kW Load per Circuit Branch							Pole Demand $ per Circuit Branch							Conductor Demand $ per Circuit Branch						
	Voltage	Load Size	1	2	3	4	5	6	7	1	2	3	4	5	6	7	1	2	3	4	5	6	7	1	2	3	4	5	6	7
Schedule 4			0.48%	0.48%	0.48%	1.96%	1.96%	1.96%	92.66%	10.09	10.09	10.09	40.77	40.77	40.77	1,926.93	59,753	59,753	59,753	54,244	54,244	55,553	102,079	55,520	55,520	55,520	41,090	41,090	101,552	315,655
Schedule 23	Secondary	0-15 kW	0.98%	0.98%	0.98%	2.88%	2.88%	2.88%	88.41%	1.51	1.51	1.51	4.41	4.41	4.41	135.44	8,941	8,941	8,941	5,868	5,868	6,010	7,175	8,307	8,307	8,307	4,445	4,445	10,986	22,187
		15+ kW	0.98%	0.98%	0.98%	2.88%	2.88%	2.88%	88.41%	1.61	1.61	1.61	4.71	4.71	4.71	144.76	9,556	9,556	9,556	6,272	6,272	6,423	7,669	8,879	8,879	8,879	4,751	4,751	11,742	23,713
	Primary		0.98%	0.98%	0.98%	2.88%	2.88%	2.88%	88.41%	0.01	0.01	0.01	0.02	0.02	0.02	0.65	43	43	43	28	28	29	35	40	40	40	21	21	53	107
Schedule 28	Secondary	0-50 kW	0.58%	0.58%	0.58%	1.92%	1.92%	1.92%	92.48%	0.63	0.63	0.63	2.09	2.09	2.09	100.44	3,754	3,754	3,754	2,777	2,777	2,844	5,321	3,488	3,488	3,488	2,104	2,104	5,199	16,454
		51-100 kW	0.58%	0.58%	0.58%	1.92%	1.92%	1.92%	92.48%	1.01	1.01	1.01	3.34	3.34	3.34	160.66	6,005	6,005	6,005	4,442	4,442	4,549	8,511	5,580	5,580	5,580	3,365	3,365	8,316	26,318
		100+ kW	0.58%	0.58%	0.58%	1.92%	1.92%	1.92%	92.48%	1.49	1.49	1.49	4.89	4.89	4.89	235.45	8,801	8,801	8,801	6,510	6,510	6,667	12,473	8,177	8,177	8,177	4,932	4,932	12,188	38,570
	Primary		0.58%	0.58%	0.58%	1.92%	1.92%	1.92%	92.48%	0.03	0.03	0.03	0.09	0.09	0.09	4.36	163	163	163	121	121	124	231	152	152	152	91	91	226	715
Schedule 30	Secondary	0-300 kW	0.33%	0.33%	0.33%	0.99%	0.99%	0.99%	96.02%	0.16	0.16	0.16	0.47	0.47	0.47	45.32	927	927	927	624	624	640	2,401	861	861	861	473	473	1,169	7,424
		300+ kW	0.33%	0.33%	0.33%	0.99%	0.99%	0.99%	96.02%	0.87	0.87	0.87	2.60	2.60	2.60	251.14	5,136	5,136	5,136	3,460	3,460	3,544	13,304	4,772	4,772	4,772	2,621	2,621	6,478	41,140
	Primary		0.33%	0.33%	0.33%	0.99%	0.99%	0.99%	96.02%	0.06	0.06	0.06	0.17	0.17	0.17	16.83	344	344	344	232	232	238	892	320	320	320	176	176	434	2,758
Schedule 48	Secondary	1-4 MW	0.94%	0.94%	0.94%	1.72%	1.72%	1.72%	92.02%	1.07	1.07	1.07	1.96	1.96	1.96	104.79	6,336	6,336	6,336	2,608	2,608	2,671	5,551	5,887	5,887	5,887	1,976	1,976	4,883	17,167
		> 4 MW								-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Primary	1-4 MW	0.94%	0.94%	0.94%	1.72%	1.72%	1.72%	92.02%	0.92	0.92	0.92	1.68	1.68	1.68	89.68	5,422	5,422	5,422	2,232	2,232	2,286	4,751	5,038	5,038	5,038	1,691	1,691	4,179	14,691
		> 4 MW								-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Schedule 41			1.31%	1.31%	1.31%	8.01%	8.01%	8.01%	72.02%	0.87	0.87	0.87	5.34	5.34	5.34	47.96	5,176	5,176	5,176	7,099	7,099	7,271	2,540	4,810	4,810	4,810	5,378	5,378	13,291	7,856

			Percentage Distribution by Branch							Customers per Circuit Branch							Pole Commitment $ per Circuit Branch							Conductor Commitment $ per Circuit Branch						
	Voltage	Load Size	1	2	3	4	5	6	7	1	2	3	4	5	6	7	1	2	3	4	5	6	7	1	2	3	4	5	6	7
Schedule 4			0.48%	0.48%	0.48%	1.96%	1.96%	1.96%	92.66%	4.59	4.59	4.59	18.54	18.54	18.54	876.32	114,432	114,432	114,432	121,427	121,427	121,427	133,767	55,888	55,888	55,888	59,304	59,304	59,304	65,332
Schedule 23	Secondary	0-15 kW	0.98%	0.98%	0.98%	2.88%	2.88%	2.88%	88.41%	1.25	1.25	1.25	3.64	3.64	3.64	111.89	31,102	31,102	31,102	23,861	23,861	23,861	17,079	15,190	15,190	15,190	11,654	11,654	11,654	8,342
		15+ kW	0.98%	0.98%	0.98%	2.88%	2.88%	2.88%	88.41%	0.26	0.26	0.26	0.76	0.76	0.76	23.21	6,451	6,451	6,451	4,949	4,949	4,949	3,543	3,151	3,151	3,151	2,417	2,417	2,417	1,730
	Primary		0.98%	0.98%	0.98%	2.88%	2.88%	2.88%	88.41%	0.00	0.00	0.00	0.00	0.00	0.00	0.10	27	27	27	21	21	21	15	13	13	13	10	10	10	7
Schedule 28	Secondary	0-50 kW	0.58%	0.58%	0.58%	1.92%	1.92%	1.92%	92.48%	0.04	0.04	0.04	0.14	0.14	0.14	6.96	1,096	1,096	1,096	947	947	947	1,063	535	535	535	463	463	463	519
		51-100 kW	0.58%	0.58%	0.58%	1.92%	1.92%	1.92%	92.48%	0.04	0.04	0.04	0.12	0.12	0.12	5.85	922	922	922	797	797	797	894	450	450	450	389	389	389	436
		100+ kW	0.58%	0.58%	0.58%	1.92%	1.92%	1.92%	92.48%	0.02	0.02	0.02	0.08	0.08	0.08	3.68	580	580	580	501	501	501	562	283	283	283	245	245	245	275
	Primary		0.58%	0.58%	0.58%	1.92%	1.92%	1.92%	92.48%	0.00	0.00	0.00	0.00	0.00	0.00	0.09	14	14	14	12	12	12	14	7	7	7	6	6	6	7
Schedule 30	Secondary	0-300 kW	0.33%	0.33%	0.33%	0.99%	0.99%	0.99%	96.02%	0.00	0.00	0.00	0.00	0.00	0.00	0.35	30	30	30	23	23	23	53	15	15	15	11	11	11	26
		300+ kW	0.33%	0.33%	0.33%	0.99%	0.99%	0.99%	96.02%	0.00	0.00	0.00	0.01	0.01	0.01	0.94	81	81	81	64	64	64	144	40	40	40	31	31	31	70
	Primary		0.33%	0.33%	0.33%	0.99%	0.99%	0.99%	96.02%	0.00	0.00	0.00	0.00	0.00	0.00	0.08	6	6	6	5	5	5	11	3	3	3	2	2	2	6
Schedule 48	Secondary	1-4 MW	0.94%	0.94%	0.94%	1.72%	1.72%	1.72%	92.02%	0.00	0.00	0.00	0.00	0.00	0.00	0.14	36	36	36	17	17	17	21	17	17	17	8	8	8	10
		> 4 MW								-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Primary	1-4 MW	0.94%	0.94%	0.94%	1.72%	1.72%	1.72%	92.02%	0.00	0.00	0.00	0.00	0.00	0.00	0.09	23	23	23	11	11	11	14	11	11	11	5	5	5	7
		> 4 MW								-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Schedule 41			1.31%	1.31%	1.31%	8.01%	8.01%	8.01%	72.02%	0.14	0.14	0.14	0.88	0.88	0.88	7.89	3,585	3,585	3,585	5,747	5,747	5,747	1,204	1,751	1,751	1,751	2,807	2,807	2,807	588

Excludes customers > 4 MW on dedicated circuits

Pole and Conductor $ per Circuit Branch (Circuit Model)

	Poles	Pole Feet	Pole Miles	Poles per Mile	Adj. Factor
California	55,705	12,071,630	2,286	24.36	0.882
Idaho	98,043	22,050,165	4,176	23.48	0.850
Oregon	381,585	73,492,032	13,919	27.41	0.992
Utah	350,360	55,698,348	10,549	33.21	1.202
Washington	100,724	18,245,816	3,456	29.15	1.055
Wyoming	160,270	37,613,177	7,124	22.50	0.814
Total	1,146,687	219,171,167	41,510	27.62	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 Phase - 1/0 ACSR	32,751	0.992	32,502	15,874	48,376
3 Phase - 1/0 ACSR	62,234	0.992	61,761	35,205	96,966
3 Phase - 447 AAC & 4\0 AAC	68,900	0.992	68,377	79,619	147,996
3 Phase -795 AAC & 477 AAC	71,562	0.992	71,019	134,976	205,995

	Pole $		Conductor $	
	Commitment	Demand	Commitment	Demand
Branches 1-5				
1 Phase - 1/0 ACSR	55,435	-	27,074	-
3 Phase - 1/0 ACSR	102,950	92,677	50,280	61,230
Total	158,385	92,677	77,354	61,230
Branch 6				
3 Phase - 447 AAC & 4\0 AAC	158,385	174,817	77,354	310,631
Branch 7				
3 Phase -795 AAC & 477 AAC	158,385	187,691	77,354	580,387

Branch pole and conductor commitment costs equals single or three phase miles per branch multiplied by 1 Phase - 1/0 ACSR Cost

Transformer Demand Costs

	Demand Related	Adjusted for 0.95 System Power Factor	Indexed to 2027	Annualized
Single Phase $ per kW	38.13	40.13	41.90	3.32
Three Phase $ per kW	38.13	40.13	41.90	3.32

Transformer Commitment Costs

	Load Size	Phase	Percent of Customers	$ per Transformer	$ Indexed to 2027	$ Annualized	Weighted $ per Transformer	Customers per Transformer	Transformer $ per Customer
Schedule 4				4,748.80	4,958.10	393.29	393.29	4.28	91.84
Schedule 23	0-15 kW	Single	80%	4,748.80	4,958.10	393.29	315.97	2.57	122.82
		Three	20%	11,424.42	11,927.95	946.16	186.02	3.04	61.11
	15+ kW	Single	54%	4,748.80	4,958.10	393.29	211.43	2.57	82.19
		Three	46%	11,424.42	11,927.95	946.16	437.50	3.04	143.73
Schedule 28	0-50 kW	Single	28%	4,748.80	4,958.10	393.29	110.78	1.36	81.26
		Three	72%	11,424.42	11,927.95	946.16	679.66	1.23	551.19
	51-100 kW	Single	14%	4,748.80	4,958.10	393.29	56.40	1.36	41.38
		Three	86%	11,424.42	11,927.95	946.16	810.47	1.23	657.27
	100+ kW	Single	2%	4,748.80	4,958.10	393.29	8.84	1.36	6.48
		Three	98%	11,424.42	11,927.95	946.16	924.89	1.23	750.06
Schedule 30	0-300 kW	Single	0%	4,748.80	4,958.10	393.29	0.78	1.50	0.52
		Three	100%	11,424.42	11,927.95	946.16	944.27	1.07	882.05
	300+ kW	Single	0%	4,748.80	4,958.10	393.29	0.41	1.50	0.27
		Three	100%	11,424.42	11,927.95	946.16	945.17	1.07	882.89
Schedule 48				11,424.42	11,927.95	946.16	946.16	1.09	866.55
Schedule 41		Single	15%	4,748.80	4,958.10	393.29	60.45	1.30	46.46
		Three	85%	11,424.42	11,927.95	946.16	800.73	1.19	671.95
Lighting				4,748.80	4,958.10	393.29	393.29	1.24	316.66

Meters - Weighted Average Installed Costs

	Voltage	Load Size	Meter Type	Cost ($)	Historic Customers	Weighted Average Installed Costs ($)
Schedule 4				241	544,721	241
			Total Annualized			19
Schedule 23	Secondary	0-15 kW	kW = 0, 1 Phase	232	4,775	15
			kW = 0, 3 Phase	354	584	3
			kW > 1, 1 Phase	232	53,790	171
			kW > 1, 3 Phase	354	13,748	67
			Total Annualized			20
		15+ kW	1 Phase	376	8,129	202
			3 Phase	354	6,992	164
			Total Annualized			29
	Primary		12.47 KV 4-wire Wye	19,358	64	19,358
			Total Annualized			1,536
Schedule 28	Secondary	0-50 kW	kW = 0, 1 Phase	376	1	0
			kW = 0, 3 Phase	354	9	1
			kW > 1, 1 Phase	376	1,220	106
			kW > 1, 3 Phase	354	3,106	254
			Total Annualized			29
		51-100 kW	1 Phase	376	523	54
			3 Phase	354	3,124	303
			Total Annualized			28
		100+ kW	1 Phase	1,739	52	39
			3 Phase	2,209	2,242	2,160
			Total Annualized			174
	Primary		12.47 KV 4-wire Wye	19,358	57	19,358
			Total Annualized			1,536
Schedule 30	Secondary	0-300 kW	1 Phase	1,739	0	3
			3 Phase	2,209	207	2,205
			Total Annualized			175
		300+ kW	1 Phase	2,209	1	2
			3 Phase	2,209	566	2,207
			Total Annualized			175
	Primary		12.47 KV 4-wire Wye	19,358	45	19,358
			Total Annualized			1,536
Schedule 48	Secondary	1-4 MW		4,133	88	4,133
			Total Annualized			328
		> 4 MW		4,133	3	4,133
			Total Annualized			328
	Primary	1-4 MW		19,358	57	19,358
			Total Annualized			1,536
		> 4 MW		19,358	37	19,358
			Total Annualized			1,536
	Transmission			293,458	13	293,458
			Total Annualized			23,278
Schedule 41		0-50 kW	kW = 0, 1 Phase	376	-	-
			kW = 0, 3 Phase	354	-	-
			kW > 1, 1 Phase	376	968	58
			kW > 1, 3 Phase	354	4,394	247
		51-300 kW	1 Phase	376	1	0
			3 Phase	354	924	52
		> 300 kW	1 Phase	2,209	-	-
			3 Phase	2,209	20	7
			Total Annualized			29

Service Drops - Weighted Average Installed Costs

	Custo-mers	% 1 & 3 Phase	Service Drop Cost ($) Over-head	Under-ground	% Over-head	Under-ground	Weighted Average Installed Costs ($)	
Schedule 4	544,721	100%					816	816
Annualized								65
Schedule 23								
0-15 kW								
kW = 0, 1 Phase	4,775	7%	1,033	858	59%	41%	962	63
kW = 0, 3 Phase	584	1%	1,240	1,183	59%	41%	1,217	10
kW > 1, 1 Phase	53,790	74%	1,180	961	59%	41%	1,091	805
kW > 1, 3 Phase	13,748	19%	1,375	1,286	59%	41%	1,339	253
Total 0-15 kW	72,897	100%						1,130
Annualized								90
15+ kW								
1 Phase	8,129	54%	2,132	1,689	59%	41%	1,952	1,050
3 Phase	6,992	46%	2,411	2,330	59%	41%	2,378	1,100
Total 15+ kW	15,121	100%						2,149
Annualized								170
Schedule 28								
0-50 kW								
1 Phase	1,221	28%	2,132	1,689	37%	63%	1,854	522
3 Phase	3,114	72%	2,411	2,330	37%	63%	2,360	1,696
Total 0-50 kW	4,335	100%						2,218
Annualized								176
51-100 kW								
1 Phase	523	14%	2,132	1,689	37%	63%	1,854	266
3 Phase	3,124	86%	2,411	2,330	37%	63%	2,360	2,022
Total 51-100 kW	3,646	100%						2,288
Annualized								181
100 + kW								
1 Phase	52	2%	3,840	4,908	37%	63%	4,510	101
3 Phase	2,242	98%	4,260	4,818	37%	63%	4,610	4,507
Total 100 + kW	2,293	100%						4,608
Annualized								366
Schedule 30								
0-300 kW								
1 Phase	0	0%	3,840	4,908	18%	82%	4,720	9
3 Phase	207	100%	4,260	4,818	18%	82%	4,720	4,710
Total 0-300 kW	208	100%						4,720
Annualized								374
300+ kW								
1 Phase	1	0%	10,362	8,600	18%	82%	8,911	9
3 Phase	566	100%	10,362	8,600	18%	82%	8,911	8,902
Total 300+ kW	566	100%						8,911
Annualized								707
Schedule 48								
1 - 4 MW (sec)	88	100%		31,008	0%	100%	31,008	31,008
Annualized								2,460
> 4 MW (sec)	3	100%		31,008	0%	100%	31,008	31,008
Annualized								2,460

Meters and Service Drops - Average Installed Costs

Meter Costs

Meter Type	Metering Standard	2025 $	2027 $	Percent Use	Installed $ per Meter
Residential					
Small Load	DM221J	222	232	49%	113.61
All Electric	DM221K	240	251	51%	127.76
				100%	241.37
0 - 15 kW					
kW = 0, 1 Phase	DM221J	222	232	100%	231.78
kW = 0, 3 Phase	DM241D	339	354	100%	353.94
kW > 1, 1 Phase	DM221J	222	232	100%	231.78
kW > 1, 3 Phase	DM241D	339	354	100%	353.94
15 - 100 kW					
1 Phase	DM221L	360	376	100%	375.87
3 Phase wo / KVAR	DM241D	339	354	100%	353.94
3 Phase with KVAR	DM241D	339	354	100%	353.94
100 - 300 kW					
1 Phase	DM231FBB	1,666	1,739	100%	1,739.43
3 Phase wo / KVAR	DM271DEC	2,116	2,209	100%	2,209.26
3 Phase with KVAR	DM271DEC	2,116	2,209	100%	2,209.26
300-1000 kW					
W/O KVAR, 1 Phase	DM271DEC	2,116	2,209	100%	2,209.26
W/O KVAR, 3 Phase	DM271DEC	2,116	2,209	100%	2,209.26
W/KVAR, 3 Phase	DM271DEC	2,116	2,209	100%	2,209.26
1000 kW and over					
Secondary Volt	DM271BEG	3,959	4,133	100%	4,133.49
Primary Metering					
13.8 KV 3-wire	DM101ACBA	12,706	13,266		13,266.02
12.47 KV 4-wire Wye	DM121BCJAD	18,541	19,358		19,358.20
24.9 KV 4-wire Wye	DM121BFIAD	24,542	25,624		25,623.69
35 KV 4-wire Wye	DM131BBAH	33,443	34,917		34,917.01
Transmission		293,458			

Service Drop Costs

	Service Conductor	2025 $	2027 $	Percent Use	$ per Service
Residential					
OH - small load	#2 Triplex	669	698	29%	203
OH - all electric	1/0 Triplex	769	803	26%	210
UG - small load	1/0 Triplex	792	827	20%	165
UG - all electric	4/0 Triplex	920	961	25%	239
					816
0 - 15 kW					
kW = 0, 1 Phase	OH - 1/0 Triplex	989	1,033		
kW = 0, 1 Phase	UG - 1/0 Triplex	822	858		
kW = 0, 3 Phase	OH - 1/0 Quadruplex	1,188	1,240		
kW = 0, 3 Phase	UG - 1/0 Quadruplex	1,133	1,183		
kW > 1, 1 Phase	OH - 4/0 Triplex	1,130	1,180		
kW > 1, 1 Phase	UG - 4/0 Triplex	920	961		
kW > 1, 3 Phase	OH - 4/0 Quadruplex	1,317	1,375		
kW > 1, 3 Phase	UG - 4/0 Quadruplex	1,232	1,286		
16 - 100 kW					
1 Phase	OH - 2-4/0 Triplex	2,042	2,132		
1 Phase	UG - 2-4/0 Triplex	1,618	1,689		
3 Phase	OH - 2-4/0 Quadruplex	2,309	2,411		
3 Phase	UG - 2-4/0 Quadruplex	2,232	2,330		
101 - 300 kW					
1 Phase	3-500 & 350N	3,678	3,840		
1 Phase	3- 750 & 500 N	4,701	4,908		
3 Phase	OH - 3-4/0 Quadruplex	4,080	4,260		
3 Phase	4-350 Quad	4,615	4,818		
301 - 1000 kW					
3 Phase	3-750 kcmil Quad.	9,925	10,362		
3 Phase	4-750 kcmil Quad.	8,237	8,600		
1000 kW and Over					
Secondary Voltage	12-1000 kcmil Quad.	29,699	31,008		
Primary Voltage	---	---	---		
Residential Percent Overhead					
Small Load	29%				
All Electric	26%				
Residential Percent Underground					
Small Load	20%				
All Electric	25%				

Customer Accounting Expense, by Schedule

Description	FERC Account		4	23	28	30	48	41	15,51,53,54	Total
		Customers	557,684	88,061	10,606	839	200	4,346	7,545	669,281
		Write-offs ($)	10,308,516	478,622	554,621	302,988	1,115,967	197,311	-	12,958,026
Supervision	901	Account 902-904	20,260,691	2,535,814	710,503	257,690	910,461	286,466	157,864	25,119,488
		$	1,105,409	138,352	38,765	14,059	49,674	15,629	8,613	1,370,501
		$ per Customer	1.98	1.57	3.65	16.76	248.37	3.60	1.14	2.05
Meter Reading Expense	902	902 Weighting Factor	-	-	-	-	-	-	-	
		Weighted Customers	-	-	-	-	-	-	-	-
		$	-	-	-	-	-	-	-	-
		$ per Customer	-	-	-	-	-	-	-	-
Cust. Receipts & Collect.	903	903 Weighting Factor	1.0	1.1	1.2	1.2	9.7	1.4	1.0	
		Weighted Customers	557,684	98,541	12,718	1,006	1,945	6,059	7,190	685,142
		$	12,244,901	2,163,643	279,235	22,089	42,697	133,039	157,864	15,043,468
		$ per Customer	21.96	24.57	26.33	26.33	213.48	30.61	20.92	22.48
Uncollectibles	904	$	8,015,790	372,171	431,267	235,600	867,764	153,427	-	10,076,020
		$ per Customer	14.37	4.23	40.66	280.81	4,338.82	35.30	-	15.05
Misc Cust Acct Expense	905	Account 902-904	20,260,691	2,535,814	710,503	257,690	910,461	286,466	157,864	25,119,488
		$	1,752	219	61	22	79	25	14	2,172
		$ per Customer	0.00	0.00	0.01	0.03	0.39	0.01	0.00	0.00
Supervision, Cust. Assist.	907-910	Customers	557,684	88,061	10,606	839	200	4,346	7,545	669,281
Info & Instructional Exp.,		$	4,964,136	783,861	94,408	7,468	1,780	38,686	67,158	5,957,497
Misc Cust Svc & Info Exp.		$ per Customer	8.90	8.90	8.90	8.90	8.90	8.90	8.90	8.90
	901-910	$	26,331,987	3,458,247	843,737	279,240	961,994	340,806	233,648	32,449,658
		$ per Customer	47.22	39.27	79.55	332.82	4,809.97	78.42	30.97	48.48

Inflation Adjustment	1.1630	1.1381	1.1139	1.0901	1.0668	
	2020	2021	2022	2023	2024	2027
Customer Accounting						
901 Supervision	706,833	699,844	884,456	733,100	3,233,550	1,370,501
902 Meter Reading Expense	2,245,673	2,432,215	2,193,524	2,462,767	2,534,544	2,642,333
903 Cust Records & Collection	13,295,839	12,573,679	12,954,582	13,975,169	14,791,914	15,043,468
904 Uncollectible Accounts	6,263,999	5,394,731	8,652,079	15,876,182	9,384,503	10,076,020
905 Misc Cust Acct Expense	8,479	830	47	(0)	0	2,172
Total	22,520,822	21,101,299	24,684,688	33,047,217	29,944,511	29,134,494
Customer Service & Info Expense						
907 Supervision	208	(166)	491	-	-	120
908 Cust Assistance Expense	3,466,926	3,935,825	3,415,781	3,817,233	3,658,070	4,075,955
909 Info & Instructional Expense	1,879,350	1,307,108	1,409,632	2,136,442	1,708,336	1,878,965
910 Misc Cust Svc & Info Expense	541	394	1,242	2,196	6,962	2,457
Total	5,347,026	5,243,161	4,827,146	5,955,871	5,373,368	5,957,497

Source: State of Oregon results of operations

Cutomers and Loads at Sales

Schedule	Voltage	Load Size	MW System Peak	MW Distribution Peak	MW Non-Coin. Peak	Customers per Transformer	Coincidence Factor for Winter Loads	Weighted Transformer Peak	Customers Historic	Customers Forecast	MWh Historic	MWh Forecast
4			1,023	1,198	5,377	4	0.67	3,602	544,721	557,684	5,600,887	5,580,023
23	Secondary	0-15 kW	83	88	761	3	1.00	761	72,897	72,880	574,636	533,358
		15+ kW	90	94	494	3	1.00	494	15,121	15,117	615,058	570,876
	Primary		0	0	1				64	64	3,075	2,855
28	Secondary	0-50 kW	60	63	214	1	1.00	214	4,335	4,450	397,639	386,663
		51-100 kW	95	100	419	1	1.00	419	3,646	3,743	641,656	623,944
		100+ kW	139	147	493	1	1.00	493	2,293	2,354	970,647	943,853
	Primary		3	3	19				57	59	17,906	17,421
30	Secondary	0-300 kW	26	27	65	1	1.00	65	208	213	177,135	178,019
		300+ kW	145	151	295	1	1.00	295	566	580	1,011,087	1,016,135
	Primary		10	10	19				45	46	75,740	75,922
48	Secondary	1-4 MW	66	66	116	1	1.00	116	88	89	477,043	477,115
		> 4 MW	9	8	27	1	1.00	27	3	3	70,238	70,249
	Primary	1-4 MW	56	56	112				57	54	460,683	403,729
		> 4 MW	280	277	448				37	44	1,126,917	2,351,814
	Transmission		300		389				13	10	3,952,246	2,540,645
41-Annual									6,308	7,808		
41-Average			32	38	245	1	1.00	245	4,444	4,346	205,869	225,796
15			0	0	1	1	1.00	1	5,979	5,841	2,218	2,189
51			0	0	2	1	1.00	2	1,293	1,306	9,077	8,881
53			0	0	2	1	1.00	2	305	302	7,983	8,105
54			0	0	10	1	1.00	10	97	96	1,367	1,365

Weighted Distribution Peaks - Tied to 12 ME December 2027 Forecast

	Voltage	Load Size	Total	Jul-24 8 17:00	Aug-24 1 17:00	Sep-24 5 17:00	Oct-24 24 08:00	Nov-24 18 18:00	Dec-24 10 09:00	Jan-25 28 08:00	Feb-25 12 08:00	Mar-25 14 08:00	Apr-25 4 07:00	May-25 30 17:00	Jun-25 9 16:00
Schedule 4			1,198	292	222	17	28	22	65	263	141	56	25	18	48
Schedule 23	Secondary	0-15 kW	88	23	17	1	2	1	5	17	9	5	2	2	4
		15+ kW	94	24	17	1	3	2	5	19	9	5	2	2	4
	Primary		0	0	0	0	0	0	0	0	0	0	0	0	0
Schedule 28	Secondary	0-50 kW	63	15	12	1	2	1	3	13	6	3	1	1	3
		51-100 kW	100	25	19	2	3	2	6	20	10	6	2	2	4
		100+ kW	147	35	26	2	5	3	9	31	16	9	3	3	6
	Primary		3	1	0	0	0	0	0	1	0	0	0	0	0
Schedule 30	Secondary	0-300 kW	27	7	5	0	1	0	2	6	3	2	1	1	1
		300+ kW	151	37	25	2	5	3	9	33	15	8	3	3	6
	Primary		10	3	2	0	0	0	1	2	1	1	0	0	0
Schedule 48	Secondary	1-4 MW	66	15	11	1	2	1	4	14	8	4	2	1	3
		> 4 MW	8	2	1	0	0	0	0	2	1	0	0	0	0
	Primary	1-4 MW	56	14	10	1	2	1	3	11	6	3	1	1	2
		> 4 MW	277	75	49	5	10	7	18	50	25	13	6	6	12
Schedule 41			38	20	11	1	0	0	0	0	0	0	0	1	3
Schedule 54			0	0	0	0	0	0	0	0	0	0	0	0	0

Distribution Peak MW @ Sales

	Voltage	Load Size		Jul-24 8 17:00	Aug-24 1 17:00	Sep-24 5 17:00	Oct-24 24 08:00	Nov-24 18 18:00	Dec-24 10 09:00	Jan-25 28 08:00	Feb-25 12 08:00	Mar-25 14 08:00	Apr-25 4 07:00	May-25 30 17:00	Jun-25 9 16:00
Schedule 4				1,237	1,377	1,130	828	992	1,141	1,211	1,290	942	1,016	847	1,138
Schedule 23	Secondary	0-15 kW		98	103	85	71	67	85	80	80	78	69	82	99
		15+ kW		103	108	89	76	71	90	89	87	83	69	94	106
	Primary			0	0	0	0	0	0	0	0	0	0	0	0
Schedule 28	Secondary	0-50 kW		65	74	65	55	48	59	58	59	58	51	59	69
		51-100 kW		107	116	103	86	80	97	92	93	95	79	94	105
		100+ kW		150	160	141	136	120	150	144	143	145	122	127	148
	Primary			3	3	3	3	2	3	3	3	3	2	2	2
Schedule 30	Secondary	0-300 kW		30	29	27	28	22	27	26	25	25	23	25	29
		300+ kW		158	154	142	158	126	160	153	142	137	124	128	150
	Primary			11	11	11	11	10	10	9	10	10	10	9	9
Schedule 48	Secondary	1-4 MW		64	65	78	67	60	67	66	70	64	67	57	68
		> 4 MW		8	9	12	7	9	8	8	8	7	7	11	9
	Primary	1-4 MW		58	63	69	54	54	55	51	57	49	51	54	59
		> 4 MW		316	306	329	300	314	318	231	228	219	259	277	284
Schedule 41				86	71	55	13	2	2	2	2	4	16	57	65
Schedule 54				0	0	0	0	1	0	0	0	0	0	0	0

Three-Year Average Weighting Factor	23.64%	16.15%	1.48%	3.40%	2.24%	5.69%	21.71%	10.90%	5.90%	2.51%	2.14%	4.23%		
	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23		
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		
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%		
	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24		
Substation Peaks	35,151	1,098,187	23,763	13,991	119,115	-	945,934	107,872	322,382	102,365	52,537	58,880		
Weighting Factor	1.22%	38.13%	0.83%	0.49%	4.14%	0.00%	32.84%	3.75%	11.19%	3.55%	1.82%	2.04%		
	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25		
Substation Peaks	889,440	246,764	77,638	328,560	9,653	120,593	275,524	839,734	111,915	85,104	115,859	308,868		
Weighting Factor	26.09%	7.24%	2.28%	9.64%	0.28%	3.54%	8.08%	24.63%	3.28%	2.50%	3.40%	9.06%		

12 ME June 2023 Distribution Substation Peak kW

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
REDACTED	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

REDACTED	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

12 ME June 2024 Distribution Substation Peak kW

Substation	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Peak Month	Peak Load
Agness Avenue	17,242	18,481	14,347	14,502	16,442	14,712	15,082	14,534	15,609	13,690	14,048	15,778	Aug-23	18,481
Albina	22,764	25,923	21,272	20,391	19,051	18,059	20,946	19,863	19,786	18,711	20,176	20,321	Aug-23	25,923
Alderwood	23,724	26,276	22,612	20,155	19,509	19,198	21,336	19,788	21,268	21,002	22,951	24,943	Aug-23	26,276
Applegate	9,836	11,184	7,705	10,234	12,284	10,540	15,695	15,610	19,056	15,441	14,231	12,513	Mar-24	19,056
Ashland	15,871	17,334	12,013	14,496	14,388	14,350	14,894	13,501	18,859	12,236	10,464	13,290	Mar-24	18,859
Bandon	1,808	1,916	1,942	2,335	2,406	2,212	2,253	2,268	2,906	3,066	2,325	1,934	Apr-24	3,066
Beall Lane	18,210	19,482	14,160	11,427	15,286	14,972	15,328	14,168	15,258	13,008	14,168	16,910	Aug-23	19,482
Belknap	28,501	31,286	24,797	19,282	21,818	19,921	20,995	19,171	20,338	17,658	20,184	23,852	Aug-23	31,286
Bend Plant+	16,553	17,837	11,959	13,351	13,829	12,691	18,908	14,385	13,947	10,450	10,550	14,173	Jan-24	18,908
Bloss	268	265	233	231	226	204	211	148	153	127	174	227	Jul-23	268
Bly+	2,292	1,957	1,200	1,025	1,232	1,088	1,340	1,174	1,281	1,520	1,732	2,283	Jul-23	2,292
Bond Street	15,927	18,173	12,270	14,575	16,061	14,244	20,004	15,328	16,137	13,852	12,410	15,188	Jan-24	20,004
Brookhurst	36,631	40,114	30,680	21,787	26,631	24,275	24,734	22,610	25,262	19,577	25,008	31,800	Aug-23	40,114
Bryant	24,862	26,109	18,386	19,525	19,680	19,875	25,514	32,083	27,626	18,004	26,476	22,424	Feb-24	32,083
Buchanan++	23,542	27,307	21,931	23,294	26,851	22,050	39,986	22,175	23,758	19,590	18,650	19,298	Jan-24	39,986
Buckaroo+	16,449	17,563	13,649	13,497	18,102	13,363	16,958	17,481	14,014	12,745	12,108	14,101	Nov-23	18,102
Calapooya	5,723	5,606	8,681	5,431	5,630	5,624	10,602	5,637	6,142	5,532	4,691	10,349	Jan-24	10,602
Campbell	20,994	23,750	18,105	14,547	15,840	15,239	16,419	14,631	15,221	15,101	15,733	19,199	Aug-23	23,750
Cannon Beach	4,668	4,269	4,462	6,208	7,264	6,647	14,282	6,859	7,110	6,474	5,366	4,611	Jan-24	14,282
Canyonville	6,440	7,447	6,037	5,931	6,859	6,405	6,200	6,300	6,500	11,600	5,000	5,700	Apr-24	11,600
Casebeer+	7,893	7,368	4,066	3,309	5,134	2,957	3,438	3,021	3,302	3,110	7,136	7,908	Jun-24	7,908
Caveman	18,794	21,362	15,982	13,138	15,681	13,361	13,613	12,653	14,619	11,815	12,539	16,123	Aug-23	21,362
Cherry Lane+	7,373	7,455	13,389	8,896	7,586	7,365	7,588	7,827	8,020	7,609	7,776	7,903	Sep-23	13,389
Chiloquin	7,961	7,969	7,766	7,838	7,380	7,023	4,715	2,707	2,989	2,846	3,186	2,708	Aug-23	7,969
China Hat	19,702	19,959	15,168	20,639	23,071	20,883	28,603	21,168	32,004	20,123	30,391	16,137	Mar-24	32,004
Circle Blvd	15,886	16,627	15,203	14,633	14,132	14,970	12,867	12,883	13,460	13,173	13,523	13,839	Aug-23	16,627
Cleveland Ave.	32,591	28,771	12,332	13,172	14,102	13,021	19,051	15,215	13,853	14,427	11,217	13,721	Jul-23	32,591

Cloake	15,284	17,746	12,462	10,567	11,579	9,162	11,813	10,898	11,543	9,387	10,383	12,691	Aug-23	17,746
Coburg	2,427	2,736	2,020	1,913	2,174	1,954	3,823	1,978	2,118	1,828	1,723	2,575	Jan-24	3,823
Columbia	31,712	31,575	25,368	24,384	26,158	25,768	32,916	30,480	30,228	27,845	27,314	30,566	Jan-24	32,916
Coquille	10,297	11,425	10,633	14,061	16,190	15,109	18,454	9,738	15,891	10,805	7,606	5,257	Jan-24	18,454
Crowfoot	15,568	16,776	12,384	13,803	15,327	13,606	14,977	14,766	15,668	13,020	12,563	14,238	Aug-23	16,776
Cully	12,091	13,300	9,548	8,174	9,515	12,375	17,523	13,613	10,323	10,379	10,520	9,957	Jan-24	17,523
Culver+	6,710	7,021	4,618	6,697	8,038	6,669	10,441	7,794	8,648	7,088	5,875	5,664	Jan-24	10,441
Dairy+	9,741	8,482	4,407	2,023	2,487	2,475	2,474	4,276	2,864	5,928	8,381	11,497	Jun-24	11,497
Dallas	33,619	39,566	28,423	27,627	33,452	30,864	44,156	29,455	34,402	29,965	25,109	27,804	Jan-24	44,156
Dalreed+	49,971	50,241	40,226	15,581	9,956	8,492	14,580	9,831	21,246	28,190	30,998	45,914	Aug-23	50,241
Deschutes+	8,040	7,923	11,717	10,927	13,086	10,602	15,832	11,287	13,390	11,956	9,024	7,250	Jan-24	15,832
Devils Lake	19,228	20,140	19,463	27,293	31,000	28,459	37,368	32,096	40,462	27,486	23,823	21,472	Mar-24	40,462
Dixon	3,423	3,882	3,044	2,751	2,783	2,481	2,742	2,602	2,630	2,175	2,578	2,775	Aug-23	3,882
Dodge Bridge+	10,857	12,092	9,177	10,040	11,761	11,361	10,828	14,874	13,743	9,120	11,191	9,505	Feb-24	14,874
Dowell	15,556	17,933	13,018	11,170	13,121	11,356	11,350	11,150	12,120	10,300	10,790	13,870	Aug-23	17,933
Easy Valley	18,318	21,372	15,356	14,661	17,081	14,242	14,456	14,481	16,000	13,743	12,741	15,984	Aug-23	21,372
Empire	8,801	8,833	10,302	15,155	17,720	16,609	17,355	16,840	19,348	15,668	13,652	10,699	Mar-24	19,348
Fern Hill	1,821	1,978	1,803	2,656	2,906	3,529	4,855	14,410	3,272	2,582	2,533	2,420	Feb-24	14,410
Fielder Creek	10,415	11,433	8,090	10,715	22,205	10,243	16,200	10,441	11,243	10,252	10,315	9,070	Nov-23	22,205
Foothills Rd	14,367	15,805	12,054	10,061	11,148	10,640	9,784	9,360	9,807	8,684	10,712	13,012	Aug-23	15,805
Garden Valley	13,693	15,907	12,426	9,837	10,816	10,534	10,863	9,832	10,641	9,340	10,852	12,480	Aug-23	15,907
Glendale++	9,371	9,794	8,786	11,585	11,416	11,568	12,543	15,124	13,693	11,896	11,853	8,675	Feb-24	15,124
Gold Hill	7,738	8,714	6,521	7,042	8,462	7,539	7,610	7,325	8,089	6,929	6,307	6,703	Aug-23	8,714
Gordon Hollow	3,990	4,333	2,949	4,047	3,992	4,381	6,390	3,720	3,850	4,480	2,730	2,900	Jan-24	6,390
Goshen	5,966	6,732	5,295	5,949	6,711	5,887	7,168	5,800	6,670	5,110	4,660	5,040	Jan-24	7,168
Grant Street	24,747	29,441	20,781	23,129	28,820	25,396	33,892	25,928	27,062	22,020	19,764	20,110	Jan-24	33,892
Green	13,951	16,120	12,180	11,568	13,205	11,165	13,102	12,117	13,008	10,922	10,219	12,703	Aug-23	16,120
Harrisburg	7,576	8,750	5,959	7,483	8,797	7,620	10,749	7,761	8,675	6,732	6,302	6,398	Jan-24	10,749
Hazelwood	6,849	8,062	5,611	6,953	8,040	6,920	7,995	7,600	8,184	7,362	6,900	8,733	Jun-24	8,733
Hillview++	26,264	33,289	23,360	28,269	31,351	27,680	30,985	28,196	28,119	21,040	20,960	21,908	Aug-23	33,289
Holladay	20,038	21,968	17,824	17,553	16,815	16,704	23,630	17,190	17,517	14,581	17,204	17,636	Jan-24	23,630
Hollywood	30,724	36,411	26,401	20,053	24,679	23,647	33,711	27,084	26,432	22,118	24,570	27,303	Aug-23	36,411
Hood River	29,455	34,111	22,248	25,111	26,360	25,503	38,374	28,030	25,502	19,984	20,303	23,744	Jan-24	38,374
Hornet+	15,605	16,342	10,666	12,203	12,348	11,468	12,277	11,720	11,846	10,948	10,505	14,251	Aug-23	16,342
Independence	18,778	20,457	8,085	9,036	10,718	9,577	12,328	10,418	11,531	8,555	7,324	8,285	Aug-23	20,457
Jacksonville	16,475	19,561	12,361	11,501	14,317	14,085	14,745	13,268	14,660	12,551	10,821	14,070	Aug-23	19,561
Jefferson	13,426	16,863	11,740	11,176	14,163	11,471	20,600	12,200	15,300	9,500	12,700	10,100	Jan-24	20,600
Jerome Prairie++	13,305	14,727	10,226	14,588	15,913	13,688	13,585	13,895	15,020	12,938	15,526	11,082	Nov-23	15,913
Junction City	8,020	8,811	6,956	7,720	8,824	7,344	9,021	7,833	8,816	7,264	6,314	6,754	Jan-24	9,021
Kennedy	6,335	15,332	11,489	11,298	13,467	12,555	17,850	16,340	15,530	13,120	12,560	13,920	Jan-24	17,850
Killingsworth	20,842	20,814	16,019	16,596	20,317	18,200	22,286	17,372	15,010	12,781	12,820	12,252	Jan-24	22,286
Knappa Svensen	2,915	3,554	3,287	4,458	4,985	4,579	6,353	4,767	5,312	4,279	2,440	3,083	Jan-24	6,353
Knott	28,804	33,754	25,472	21,881	27,048	25,762	35,794	33,556	30,672	38,005	41,869	35,527	May-24	41,869
Lakeport++	18,191	18,584	16,447	17,159	18,366	16,720	19,035	19,053	18,643	17,687	17,168	17,518	Feb-24	19,053
Lancaster	7,931	8,513	7,339	8,900	8,658	4,945	10,506	3,003	7,004	6,197	7,526	15,694	Jun-24	15,694
Lebanon++	31,088	36,478	27,259	28,732	31,254	32,601	34,213	28,459	31,445	26,062	25,256	27,889	Aug-23	36,478
Lincoln	33,638	37,642	31,502	29,284	33,232	30,986	38,741	32,212	34,515	28,288	28,778	30,390	Jan-24	38,741
Lockhart	10,708	11,094	11,464	16,694	21,046	18,199	20,668	19,885	22,284	18,617	16,295	12,665	Mar-24	22,284
Lyons	17,848	18,325	16,757	18,770	19,126	19,715	20,909	21,041	21,691	19,090	18,668	16,576	Mar-24	21,691
Madras+	18,340	20,056	14,457	18,237	19,213	17,860	26,350	18,565	18,653	16,010	13,788	15,019	Jan-24	26,350
Mallory	12,545	19,418	13,805	11,959	14,527	13,763	16,411	11,820	11,680	9,434	9,728	10,880	Aug-23	19,418
Marys River	14,355	-	11,648	13,981	15,490	15,195	16,717	15,434	16,980	14,801	13,535	14,062	Mar-24	16,980
McKay	12,932	13,064	9,318	8,095	8,504	8,398	11,818	8,408	8,369	7,442	8,425	10,295	Aug-23	13,064
Medco	16,282	15,944	16,105	16,136	16,845	16,729	12,826	9,043	5,203	10,829	10,195	8,352	Nov-23	16,845
Medford	33,761	37,597	34,270	22,826	25,923	24,213	25,354	18,340	29,394	20,901	31,294	30,927	Aug-23	37,597
Merlin	21,443	24,962	16,361	24,806	28,048	22,047	22,447	23,007	26,109	21,424	19,246	16,602	Nov-23	28,048
Merrill+	8,455	7,679	4,643	4,781	4,933	4,842	9,813	9,792	5,927	6,238	10,668	8,612	May-24	10,668
Mile High+	9,789	10,256	9,549	11,258	11,910	11,717	13,710	12,399	12,547	11,669	11,759	8,701	Jan-24	13,710
Murder Creek	53,332	57,188	47,488	42,399	49,157	49,236	56,406	51,298	64,799	71,222	52,823	46,094	Apr-24	71,222

Oak Knoll	18,020	21,344	13,706	15,125	16,950	17,034	21,977	17,138	18,391	15,949	13,484	15,397	Jan-24	21,977
O'Brien++	1,187	1,374	986	1,353	2,811	1,303	1,519	1,548	1,572	1,367	1,304	1,035	Nov-23	2,811
REDACTED	27,237	27,924	26,152	23,957	23,597	23,078	26,258	27,337	27,782	25,158	24,968	25,575	Aug-23	27,924
Overpass+	31,109	34,655	23,697	30,067	34,247	30,433	40,295	31,181	32,777	31,468	26,717	28,445	Jan-24	40,295
Pallette	412	382	279	381	439	450	610	431	427	444	330	302	Jan-24	610
Park Street	31,910	35,833	26,630	24,589	28,057	23,791	24,363	23,556	26,272	22,015	22,810	27,633	Aug-23	35,833
Parkrose	27,565	32,694	23,644	22,065	25,309	23,094	34,557	26,346	42,716	22,522	21,754	24,324	Mar-24	42,716
Pendleton	22,043	22,498	15,733	16,171	17,789	17,040	23,217	17,204	16,632	14,297	13,476	17,001	Jan-24	23,217
Pilot Butte+	18,037	19,099	13,831	13,553	15,705	13,746	19,610	14,310	14,420	12,530	11,000	14,560	Jan-24	19,610
Prineville	34,536	39,458	28,305	34,893	39,011	33,135	48,109	35,986	37,073	34,289	32,390	32,967	Jan-24	48,109
Prospect Central+	2,258	2,121	2,514	4,637	1,931	4,183	5,023	2,251	4,308	4,802	4,740	4,422	Jan-24	5,023
Queen Ave	37,795	42,702	30,512	26,355	32,028	28,867	37,728	30,017	29,892	24,761	27,384	30,943	Aug-23	42,702
Redmond 115	36,454	40,009	29,043	36,267	40,821	34,851	46,296	36,601	37,915	20,813	20,039	20,250	Jan-24	46,296
REDACTED	15,061	15,756	12,534	15,991	18,294	15,323	17,659	16,290	18,519	14,610	13,640	12,310	Mar-24	18,519
REDACTED	11,182	10,898	10,883	10,810	10,892	10,773	11,625	12,328	12,141	12,047	11,859	11,531	Feb-24	12,328
REDACTED	21,937	25,705	19,153	18,946	21,979	17,986	21,992	19,003	21,680	17,677	19,014	18,530	Aug-23	25,705
Ross Ave	6,291	6,779	4,855	5,309	5,382	5,534	5,964	5,599	5,677	4,878	4,518	5,525	Aug-23	6,779
Roxy Ann	14,754	16,792	11,495	7,746	10,126	7,486	8,051	7,066	7,242	6,152	8,965	11,602	Aug-23	16,792
Russelville	28,298	34,734	26,288	23,566	29,230	29,938	41,888	28,909	27,399	22,755	27,204	27,437	Jan-24	41,888
Sage Road	29,654	31,472	28,857	24,056	23,972	24,088	23,454	24,328	22,600	26,249	21,676	27,032	Aug-23	31,472
Scenic	29,164	32,303	24,242	18,202	22,268	20,553	20,661	18,969	20,137	17,332	20,108	25,119	Aug-23	32,303
Scio	5,352	5,791	10,374	5,040	5,726	5,326	7,594	5,098	5,461	4,400	4,008	4,148	Sep-23	10,374
Seaside	14,310	14,547	14,199	18,279	20,321	22,887	26,289	20,481	21,072	20,206	15,842	14,114	Jan-24	26,289
Shevlin Park	23,601	25,516	15,813	17,516	19,427	19,191	26,452	19,920	19,825	17,186	15,058	20,656	Jan-24	26,452
Southgate++	13,713	14,765	13,610	12,691	13,860	12,838	14,355	13,336	15,410	13,242	11,883	13,313	Mar-24	15,410
State Street	18,780	18,274	23,152	26,956	30,775	28,632	32,128	29,404	33,836	27,789	24,551	20,177	Mar-24	33,836
Stayton++	35,618	38,959	27,711	29,976	36,604	31,567	39,938	32,025	34,635	28,446	25,044	29,425	Jan-24	39,938
Stevens Road++	22,273	27,433	18,420	14,855	19,173	17,428	17,580	14,201	16,333	12,891	14,551	23,484	Aug-23	27,433
Sutherlin	11,557	13,156	10,248	10,315	11,554	10,362	12,952	10,533	12,009	10,547	10,125	11,531	Aug-23	13,156
Sweet Home+	23,182	25,982	19,564	23,596	27,558	25,261	27,961	24,769	26,446	20,733	17,032	20,442	Jan-24	27,961
Takelma	8,678	10,066	7,205	9,331	10,718	10,384	9,809	9,281	10,277	16,477	8,168	9,469	Apr-24	16,477
Talent	19,326	22,864	15,061	16,093	19,628	18,314	19,227	17,666	19,195	15,212	13,975	17,392	Aug-23	22,864
Texum++	11,000	11,598	9,516	13,991	12,533	11,758	12,720	12,080	11,800	11,940	9,920	11,070	Oct-23	13,991
Umatilla	13,091	14,087	10,388	8,999	9,554	9,290	14,455	9,414	9,626	8,117	9,874	15,049	Jun-24	15,049
Vernon	31,052	37,758	25,357	22,276	26,880	26,311	37,593	25,938	26,507	20,796	23,320	25,604	Aug-23	37,758
Vilas Road+	20,268	22,879	17,742	14,317	15,912	15,672	15,795	14,345	15,056	13,554	15,818	18,780	Aug-23	22,879
Village Green+	12,199	14,249	10,632	12,298	14,240	12,623	18,546	11,539	12,592	10,441	9,832	9,778	Jan-24	18,546
Vine Street++	21,732	25,170	17,608	14,493	15,828	15,159	20,016	14,648	15,234	12,539	15,727	17,648	Aug-23	25,170
Warrenton	17,252	18,180	16,470	17,795	19,263	18,025	20,320	20,109	21,217	18,949	16,945	17,016	Mar-24	21,217
Weston	9,112	11,089	8,495	9,031	8,760	5,862	6,529	5,842	7,077	5,696	5,302	8,076	Aug-23	11,089
Westside+	13,894	14,648	10,463	11,763	13,426	12,312	14,707	14,068	13,567	10,850	11,049	11,711	Jan-24	14,707
REDACTED	11,250	14,702	8,801	8,696	15,190	8,922	5,413	5,200	5,054	4,885	6,514	6,750	Nov-23	15,190
White City	40,764	42,582	36,417	34,310	38,152	37,157	38,813	39,923	38,257	35,466	35,606	39,642	Aug-23	42,582
Winchester	23,461	27,361	20,265	18,697	21,392	17,281	21,200	18,580	21,072	17,239	16,748	20,157	Aug-23	27,361
Yew Ave	19,082	20,457	14,911	15,960	18,013	15,871	22,974	16,436	17,676	18,076	16,576	19,875	Jan-24	22,974

12 ME June 2025 Distribution Substation Peak kW

Substation	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Peak Month	Peak Load
Agness Avenue	19,807	19,259	16,643	13,690	15,525	16,390	17,149	17,402	15,420	15,504	15,188	18,900	Jul-24	19,807
Albina	24,004	25,957	24,813	20,645	21,699	22,441	22,441	23,906	21,367	20,488	26,283	25,840	May-25	26,283
Alderwood	26,659	27,460	25,522	21,439	19,963	20,463	20,758	21,827	20,708	21,174	22,344	25,570	Aug-24	27,460
Applegate	15,669	15,314	13,368	14,355	16,157	28,299	18,999	19,839	15,490	45,445	11,946	9,538	Apr-25	45,445
Ashland	17,973	17,129	15,484	12,194	15,400	15,695	16,075	22,614	12,995	11,729	12,278	15,653	Feb-25	22,614
Bandon	2,066	2,010	2,085	2,218	2,908	3,333	2,671	2,780	3,276	2,579	2,652	2,039	Dec-24	3,333
Beacon	5,906	-	-	47,555	5,109	5,484	6,000	6,188	4,594	3,656	5,578	7,172	Oct-24	47,555
Beall Lane	19,090	19,512	18,703	13,535	13,676	16,559	16,664	16,383	14,379	12,762	16,523	18,070	Aug-24	19,512
Belknap	29,634	28,780	26,725	19,035	20,200	22,981	23,139	23,561	18,733	17,168	22,994	27,442	Jul-24	29,634
Bend Plant+	19,139	18,867	14,740	16,323	13,116	14,272	14,352	16,743	12,653	12,063	11,615	15,454	Jul-24	19,139
Bloss	232	221	206	232	216	243	237	253	206	179	190	200	Feb-25	253

Bly+	2,102	2,808	1,990	1,600	1,448	1,368	1,386	2,205	2,486	3,539	3,420	4,648	Jun-25	4,648
REDACTED	117	189	79	106	137	150	151	169	234	155	108	82	Mar-25	234
Bond Street	20,320	20,250	15,328	13,887	14,977	16,102	19,195	19,406	13,922	13,852	17,789	22,289	Jun-25	22,289
Brookhurst	40,238	38,636	35,669	22,200	26,156	29,220	29,215	30,469	22,901	20,189	29,826	36,668	Jul-24	40,238
Bryant	25,848	22,951	14,168	10,918	17,469	13,203	12,391	17,113	18,464	18,051	18,480	23,153	Jul-24	25,848
Buchanan++	25,597	29,006	23,571	20,293	22,220	24,732	26,443	26,293	21,425	19,837	16,748	24,168	Aug-24	29,006
Buckaroo+	18,066	16,300	14,483	12,885	13,471	14,357	15,407	15,712	13,461	12,679	12,921	15,529	Jul-24	18,066
Calapooya	5,722	5,890	5,217	5,701	5,217	5,890	6,142	6,815	5,048	5,027	4,544	6,142	Feb-25	6,815
Campbell	22,590	22,312	20,756	14,576	15,595	17,311	16,749	17,508	13,786	12,728	17,528	21,206	Jul-24	22,590
Cannon Beach	4,846	4,548	4,776	5,009	7,272	14,362	8,119	11,328	6,281	5,633	4,655	4,981	Dec-24	14,362
Canyonville	6,900	7,000	6,600	5,700	6,300	6,700	7,800	10,300	12,700	5,700	5,300	6,400	Mar-25	12,700
Casebeer+	8,365	8,587	5,438	3,035	3,926	3,455	3,710	4,491	3,009	3,137	6,859	8,580	Aug-24	8,587
Caveman	20,414	20,344	18,324	12,045	12,803	14,432	16,266	16,508	14,185	13,885	14,984	19,058	Jul-24	20,414
Cherry Lane+	7,999	9,943	9,077	7,737	8,113	7,681	7,609	8,255	7,821	8,550	13,222	10,963	May-25	13,222
Chiloquin	2,811	6,444	2,729	3,103	5,234	5,408	5,131	5,225	2,975	2,721	9,814	3,520	May-25	9,814
China Hat	21,879	11,786	22,054	18,383	21,421	21,848	23,968	28,334	31,720	31,641	16,864	18,826	Mar-25	31,720
Circle Blvd	15,091	15,350	14,045	13,409	12,648	12,664	13,002	13,633	13,645	13,201	13,088	14,866	Aug-24	15,350
Clearwater	297	221	281	372	454	552	853	596	814	427	306	225	Jan-25	853
Cleveland Ave.	31,832	34,486	28,119	22,047	27,276	29,706	31,404	34,415	26,935	26,461	21,647	29,238	Aug-24	34,486
Cloake	17,039	15,469	15,316	9,352	10,359	12,223	22,020	13,594	10,418	9,000	10,301	15,715	Jan-25	22,020
Coburg	2,725	2,689	2,364	2,364	1,951	2,259	2,382	2,382	1,898	3,155	1,626	2,435	Apr-25	3,155
Columbia	35,869	34,680	34,092	27,959	29,532	31,125	32,079	32,702	27,562	27,039	27,176	40,500	Jun-25	40,500
Coquille	10,083	10,098	11,194	15,920	16,848	20,426	20,534	19,996	21,391	14,685	12,978	15,457	Mar-25	21,391
Crowfoot	17,262	15,609	15,539	12,961	14,016	15,891	16,570	17,578	13,289	12,914	11,637	16,242	Feb-25	17,578
Cully	15,217	13,192	12,151	10,548	11,195	13,248	16,820	13,585	10,717	9,423	9,760	12,207	Jan-25	16,820
Culver+	8,258	6,550	6,223	6,518	7,161	8,406	8,332	9,777	11,306	7,151	5,337	6,613	Mar-25	11,306
Dairy+	12,582	11,351	22,510	3,491	5,959	5,914	2,454	3,695	6,727	2,478	10,287	10,246	Sep-24	22,510
Dallas	38,679	37,354	34,852	26,351	31,156	35,058	35,324	36,386	29,805	25,793	22,275	34,499	Jul-24	38,679
Dalreed+	49,532	53,184	40,700	27,718	10,711	13,648	9,589	12,568	16,659	22,858	42,033	60,889	Jun-25	60,889
Deschutes+	8,740	13,925	8,882	9,565	11,985	12,434	13,280	16,547	9,783	9,580	7,246	8,520	Feb-25	16,547
Devils Lake	21,111	19,629	20,480	24,269	32,030	30,665	34,189	34,870	28,259	24,979	21,501	22,988	Feb-25	34,870
Dixon	3,567	3,431	3,169	2,236	2,409	2,855	2,831	2,700	2,391	2,119	2,536	3,159	Jul-24	3,567
Dodge Bridge+	11,864	11,585	10,306	9,554	10,106	13,156	13,436	13,668	9,561	8,477	19,153	10,303	May-25	19,153
Dowell	17,139	16,330	14,810	9,830	11,180	12,340	14,150	14,710	11,050	9,930	12,630	16,240	Jul-24	17,139
Easy Valley	20,302	19,216	16,947	12,941	14,639	15,727	18,309	18,915	14,532	13,103	14,294	19,099	Jul-24	20,302
Empire	9,234	9,398	11,074	13,957	18,773	18,293	19,441	21,000	15,691	14,953	12,727	10,125	Feb-25	21,000
Fern Hill	2,097	1,928	2,153	2,765	3,610	3,673	3,680	4,827	3,089	2,491	3,096	1,942	Feb-25	4,827
Fielder Creek	11,623	10,779	9,471	10,104	9,956	11,306	12,530	13,015	10,252	9,872	8,269	10,821	Feb-25	13,015
Foothills Rd	15,395	15,007	13,750	9,261	9,601	10,478	10,642	11,020	9,145	8,277	11,747	13,888	Jul-24	15,395
REDACTED	143,110	143,483	148,810	211,006	161,970	167,450	172,833	179,693	184,700	185,117	189,200	195,583	Oct-24	211,006
Garden Valley	16,031	15,082	14,684	10,242	11,719	10,477	16,512	11,859	17,027	8,742	10,781	14,367	Mar-25	17,027
Glendale++	9,813	9,526	9,058	11,120	11,582	12,444	13,701	13,332	11,225	10,281	9,885	9,278	Jan-25	13,701
Gordon Hollow	4,210	3,930	3,150	3,280	3,590	4,070	6,390	3,720	3,850	4,480	2,730	2,900	Jan-25	6,390
Goshen	6,540	6,310	5,550	4,960	5,660	6,390	7,168	5,800	6,670	5,110	4,660	5,040	Jan-25	7,168
Grant Street	28,080	25,884	24,542	22,425	25,672	29,617	28,246	29,220	24,977	20,572	18,215	26,423	Dec-24	29,617
Green	15,422	14,766	14,977	10,477	11,133	12,891	24,656	15,984	15,328	11,063	13,898	14,461	Jan-25	24,656
Harrisburg	8,033	8,060	7,233	6,987	7,330	8,587	9,606	9,457	7,831	7,031	6,029	7,884	Jan-25	9,606
Hazelwood	9,218	8,859	7,952	7,488	7,741	9,000	9,197	7,600	7,615	7,066	6,900	8,501	Jul-24	9,218
Hillview++	37,057	34,724	27,264	22,066	27,338	24,909	28,480	27,020	22,788	18,828	19,291	27,878	Jul-24	37,057
Holladay	21,319	20,515	21,982	16,767	17,143	17,785	17,976	19,280	17,294	15,367	17,263	19,765	Sep-24	21,982
Hollywood	36,194	34,672	32,699	21,556	24,684	26,249	26,089	29,934	23,451	21,526	23,130	31,540	Jul-24	36,194
Hood River	31,752	32,198	26,126	21,588	25,473	27,758	31,037	33,038	23,259	20,473	20,387	28,858	Feb-25	33,038
Hornet+	17,491	15,770	13,504	11,011	12,720	13,023	13,150	22,452	11,707	11,391	11,429	14,934	Feb-25	22,452
REDACTED	64,338	66,348	67,378	69,908	70,818	69,018	70,028	70,498	70,588	69,912	71,008	75,718	Jun-25	75,718
Independence	11,930	10,418	15,422	8,824	9,129	10,980	11,027	11,379	9,820	8,063	7,301	9,949	Sep-24	15,422
Jacksonville	18,689	17,866	15,736	11,222	14,895	15,864	15,834	20,288	12,931	11,672	12,555	16,426	Feb-25	20,288
Jefferson	13,000	12,500	11,300	8,600	10,200	11,100	12,400	13,400	10,200	9,200	10,200	12,300	Feb-25	13,400
Jerome Prairie++	14,457	13,473	11,307	12,488	13,585	14,767	17,438	17,888	13,754	12,320	9,592	12,657	Feb-25	17,888
Junction City	8,834	8,117	8,013	7,225	7,661	8,810	9,593	9,404	7,503	36,504	30,949	8,245	Apr-25	36,504

Kennedy	18,450	17,250	16,580	12,800	14,510	14,860	16,010	17,430	14,090	13,460	12,700	16,620	Jul-24	18,450
Killingsworth	15,491	15,729	15,812	13,912	14,612	16,311	18,849	16,624	14,407	14,003	12,361	14,525	Jan-25	18,849
Knappa Svensen	3,509	3,326	3,537	3,625	5,119	4,936	5,418	7,200	4,507	4,373	3,410	3,104	Feb-25	7,200
Knott	33,032	21,630	20,622	23,091	29,435	24,446	30,152	29,569	32,356	32,392	47,387	38,310	May-25	47,387
Lakeport++	18,934	18,214	17,447	18,093	19,180	20,026	19,640	20,201	18,250	18,031	19,008	17,743	Feb-25	20,201
Lancaster	9,366	9,283	8,381	12,346	8,927	11,076	12,679	11,919	10,506	9,283	8,179	8,963	Jan-25	12,679
Lebanon++	34,859	34,174	32,759	27,728	28,812	32,410	34,237	35,350	31,445	26,464	24,543	32,453	Feb-25	35,350
Lemolo 1	889	860	861	923	984	1,046	1,105	1,140	1,169	1,197	1,226	1,254	Jun-25	1,254
Lincoln	35,620	34,844	33,192	27,810	31,609	32,212	33,517	36,863	30,050	28,382	32,173	36,880	Jun-25	36,880
Lockhart	11,790	10,629	12,605	19,608	19,400	21,616	22,589	23,666	18,062	16,848	15,341	11,510	Feb-25	23,666
Lyons	19,063	16,770	18,202	18,809	19,672	21,410	21,937	20,760	19,327	18,668	17,977	18,571	Jan-25	21,937
Madras+	18,158	17,460	14,852	14,156	16,815	20,056	21,521	23,949	16,782	19,488	14,970	16,879	Feb-25	23,949
Mallory	28,301	13,968	13,406	9,813	12,269	11,792	11,567	13,083	10,444	9,602	8,872	12,690	Jul-24	28,301
Marys River	16,594	70	14,924	15,820	14,186	15,135	17,877	18,158	15,135	14,994	13,289	16,049	Feb-25	18,158
McKay	13,293	13,187	11,732	7,382	8,154	15,216	9,721	11,111	7,801	6,922	14,530	12,360	Dec-24	15,216
Medco	11,558	8,102	6,163	3,821	11,117	4,954	1,824	10,925	13,114	9,350	10,906	11,213	Mar-25	13,114
Medford	38,052	37,396	36,938	23,853	25,925	30,696	28,329	28,390	29,662	24,524	28,643	35,102	Jul-24	38,052
Merlin	23,323	21,709	18,205	20,836	22,283	24,940	29,936	30,840	22,524	19,916	15,259	20,892	Feb-25	30,840
Merrill+	9,007	8,425	5,841	3,984	9,653	4,672	4,715	5,885	5,042	6,654	6,597	8,282	Nov-24	9,653
Mile High+	8,514	10,993	8,622	11,791	12,528	13,233	13,165	15,983	12,389	11,817	9,705	8,417	Feb-25	15,983
Minam	47	44	36	33	33	24	13	47	47	42	2,278	25,056	Jun-25	25,056
Murder Creek	50,224	47,547	49,116	43,488	46,714	46,020	46,623	48,601	42,376	43,288	43,628	43,073	Jul-24	50,224
Oak Knoll	21,435	20,326	18,462	15,077	18,923	18,947	18,920	21,499	16,952	15,112	14,037	18,781	Feb-25	21,499
O'Brien++	1,357	1,240	1,045	1,299	1,509	1,675	1,685	2,017	1,475	1,353	1,064	4,277	Jun-25	4,277
REDACTED	28,876	30,108	27,769	24,204	26,113	26,977	22,283	26,922	25,553	24,623	23,773	24,746	Aug-24	30,108
Overpass+	36,759	35,580	29,462	31,293	30,154	33,402	34,007	38,738	30,525	29,605	25,535	31,641	Feb-25	38,738
REDACTED	3,383	3,364	3,789	3,421	3,374	3,450	3,451	3,647	4,424	4,316	3,414	3,381	Mar-25	4,424
Pallette	421	399	360	319	396	437	573	616	374	381	287	343	Feb-25	616
Parkrose	31,903	31,013	29,160	22,336	25,674	27,180	27,557	31,108	23,593	22,117	22,116	28,702	Jul-24	31,903
Pendleton	22,737	22,531	20,835	14,019	15,237	17,490	19,158	21,735	15,128	13,133	15,176	20,927	Jul-24	22,737
Pilot Butte+	19,460	18,510	15,200	11,950	13,440	14,800	19,610	14,310	14,420	12,530	11,000	14,560	Jan-25	19,610
Powell Butte	3,837	3,465	3,225	3,712	3,535	4,242	4,611	4,920	3,744	3,834	3,622	3,459	Feb-25	4,920
Prineville	41,203	38,768	32,462	30,758	33,555	37,649	40,779	47,081	33,600	30,920	30,197	35,792	Feb-25	47,081
Prospect Central+	2,258	2,121	2,514	4,637	1,931	4,183	34,034	34,516	18,427	33,426	32,910	5,620	Feb-25	34,516
Queen Ave	40,972	40,058	35,898	25,318	28,459	32,373	39,273	33,558	26,603	23,730	25,395	37,994	Jul-24	40,972
Redmond 115	38,031	41,590	32,580	13,005	13,815	34,878	39,305	45,321	32,861	31,241	27,451	36,081	Feb-25	45,321
REDACTED	4,645	9,560	10,123	2,047	6,030	1,826	11,226	6,349	8,187	10,001	6,373	5,638	Jan-25	11,226
REDACTED	15,520	14,800	13,510	12,290	12,490	14,840	17,759	17,809	15,380	12,570	11,240	13,870	Feb-25	17,809
REDACTED	11,953	11,859	11,484	12,328	12,188	12,328	12,750	12,422	12,188	12,609	12,094	11,813	Jan-25	12,750
REDACTED	24,089	22,344	21,789	17,161	18,733	21,053	35,612	25,109	18,316	32,847	15,021	22,039	Jan-25	35,612
Ross Ave	14,812	6,838	5,890	5,040	5,658	5,721	5,751	7,051	5,288	5,083	4,713	6,129	Jul-24	14,812
Roxy Ann	15,926	14,977	13,219	7,488	14,730	7,945	8,086	8,648	6,574	5,766	10,723	13,746	Jul-24	15,926
Russelville	34,477	33,429	30,370	22,264	26,304	28,639	29,065	34,399	25,159	25,543	22,239	30,414	Jul-24	34,477
Sage Road	31,251	30,600	28,775	22,456	21,887	25,118	25,157	25,061	26,553	19,783	24,936	29,489	Jul-24	31,251
Savage Rapids	1,345	1,345	1,347	134	62	63	63	62	53	49	1,235	1,357	Jun-25	1,357
Scenic	30,849	29,933	27,493	17,449	20,872	23,058	22,845	22,595	17,871	16,540	23,783	29,222	Jul-24	30,849
Scio	5,479	5,174	4,922	5,684	5,016	5,385	6,182	6,340	4,658	4,295	3,586	5,379	Feb-25	6,340
Seaside	15,529	13,885	33,209	16,133	36,479	40,097	28,052	32,412	17,831	20,545	6,505	6,317	Dec-24	40,097
Shevlin Park	29,445	27,398	20,828	21,197	20,476	21,270	21,713	25,109	19,930	18,187	17,837	25,446	Jul-24	29,445
Southgate++	16,840	15,105	16,406	12,422	13,371	15,539	19,219	16,945	13,277	12,598	11,953	14,789	Jan-25	19,219
State Street	18,934	18,221	20,956	24,553	31,634	31,572	34,360	36,481	29,188	26,418	22,472	19,110	Feb-25	36,481
Stayton++	38,563	36,744	34,608	27,876	30,305	39,966	37,668	40,121	29,144	27,796	23,814	35,972	Feb-25	40,121
Stevens Road++	24,845	25,402	23,689	13,161	17,052	18,679	19,328	20,230	14,531	13,734	18,001	23,437	Aug-24	25,402
Sutherlin	14,484	13,472	13,317	10,884	12,023	13,008	22,430	14,991	11,517	20,377	9,802	13,219	Jan-25	22,430
Sweet Home+	26,123	25,745	24,245	21,996	22,102	26,001	29,957	30,927	21,818	20,148	17,037	24,055	Feb-25	30,927
Takelma	10,113	9,164	8,179	8,098	10,920	10,956	11,880	12,300	9,273	8,126	6,609	8,459	Feb-25	12,300
Talent	22,492	21,938	19,382	15,266	20,379	22,153	21,742	24,380	17,219	15,407	15,349	19,649	Feb-25	24,380
Texum++	15,650	14,170	12,800	14,070	14,210	15,610	15,940	17,879	13,970	11,360	9,520	12,040	Feb-25	17,879
Umatilla	18,561	14,863	13,333	9,789	9,770	11,111	14,066	15,792	9,424	8,692	11,533	14,724	Jul-24	18,561

Vernon	37,368	35,212	32,673	21,455	30,034	27,301	27,658	31,505	25,369	22,333	23,250	36,024	Jul-24	37,368
Vilas Road+	22,772	22,403	20,764	14,468	14,622	17,265	17,169	16,965	14,375	13,447	17,172	21,207	Jul-24	22,772
Village Green+	13,665	13,454	12,791	10,788	12,285	13,949	15,870	16,193	12,727	9,900	8,980	12,164	Feb-25	16,193
Vine Street++	24,938	23,320	21,516	12,867	15,070	16,594	16,031	16,711	13,594	12,656	13,805	22,266	Jul-24	24,938
Warrenton	19,723	18,475	18,703	17,965	20,197	22,676	21,586	21,656	19,283	18,475	16,717	36,000	Jun-25	36,000
Weston	8,689	9,589	8,644	7,464	8,700	6,086	6,348	6,578	5,617	8,106	5,576	8,851	Aug-24	9,589
Westside+	14,446	13,474	17,723	12,408	13,840	14,753	15,151	16,539	13,881	13,299	11,324	12,955	Sep-24	17,723
REDACTED	5,042	4,896	4,638	4,998	10,152	17,969	12,848	7,940	5,099	5,144	4,313	6,648	Dec-24	17,969
White City	43,618	47,264	41,572	35,625	36,544	40,050	41,550	39,650	36,681	33,479	36,917	43,622	Aug-24	47,264
Winchester	26,644	24,640	24,301	70,000	18,000	20,566	33,449	24,409	17,478	17,192	16,819	24,359	Oct-24	70,000
Yew Ave	25,114	20,175	18,336	16,096	17,876	19,975	20,975	24,974	16,936	15,876	15,316	21,295	Jul-24	25,114
Youngs Bay	17,430	17,070	17,570	16,850	20,280	20,520	21,760	24,680	19,020	17,590	16,400	15,760	Feb-25	24,680

Present Revenues and Net Write-Offs by Class, Schedule and Voltage

				23		28		30		48				
		Total	4	Secondary	Primary	Secondary	Primary	Secondary	Primary	Secondary	Primary	Transmission	41	51,15,53,54
Present Revenue ($)	Residential	801,274,908	801,274,908											
Present Revenue ($)	Commercial	817,785,055		162,040,118	344,135	186,141,843	1,400,262	95,638,229	5,239,482	28,901,103	161,994,548	176,085,335		
Present Revenue ($)	Industrial	120,588,214		2,295,217	14,577	7,143,206	340,241	14,549,430	1,623,531	20,134,308	72,704,834	1,782,870		
Present Revenue ($)	Irrigation	34,895,623											34,895,623	
Present Revenue ($)	Lighting	4,644,962												4,644,962
Net Write-off $	Residential	10,308,516	10,308,516	-	-	-	-	-	-	-	-	-	-	-
Net Write-off $	Commercial	2,405,928	-	476,723	1,012	547,630	4,120	281,368	15,415	85,027	476,589	518,044	-	-
Net Write-off $	Industrial	46,270	-	881	6	2,741	131	5,583	623	7,726	27,897	684	-	-
Net Write-off $	Irrigation	197,311	-	-	-	-	-	-	-	-	-	-	197,311	-
Net Write-off $	Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-

Annual Charges		
	System Transmission	Distribution
Levelized Income Taxes	0.87%	0.79%
Levelized Property Tax	0.68%	0.74%
Total	1.55%	1.53%
Levelized Income & Property Taxes	$15.50	$15.30
Expected Life	65	54
Nominal Interest Rate	7.56%	7.56%
Present Value	$203.36	$198.55
Removal Cost Per $1,000 Investment	$179.61	$472.09
Present Value	$1.58	$9.25
Investment and Taxes	$1,204.94	$1,207.79
PVCD Factor	0.041276	0.042267
PVCD $	$49.74	$51.05
Total	$1,254.67	$1,258.84
Annual Charge	$65.02	$67.12
Annual Economic Carrying	6.50%	6.71%
Adm & Gen Expense Loading Factor	1.22%	1.22%
Annual Econ Carrying + A&G Loading	7.72%	7.93%
Weighted Cost of Capital	7.56%	
Average Inflation	2.18%	
Real Cost of Capital	5.26%	

Administrative & General Expense Loading Factor			
	Administrative and General Expenses ($000)	Electric Plant in Service ($000)	Admin. & General to Electric Plant In Service Loading Factor
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%
2023	1,953,618	33,849,235	5.77%
2024	656,914	37,952,649	1.73%
10-Year Average			1.22%
Sources: FERC Form 1, Page 323, line 197 FERC Form 1, Page 207, line 104			

Transmission O & M Expenses

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Transmission O&M Expense	215,664	203,261	204,806	206,506	218,367	210,892	232,302	239,534	258,594	272,279
Wheeling	148,425	130,789	134,473	135,022	145,825	141,188	159,058	163,235	165,142	176,350
Net Transmission O&M	67,239	72,472	70,333	71,484	72,541	69,703	73,243	76,299	93,452	95,928
Transmission Plant	5,910,756	6,051,720	6,222,286	6,353,045	6,478,620	7,630,241	7,892,551	8,048,836	8,213,839	10,994,499
Transmission O&M Loading	1.14%	1.20%	1.13%	1.13%	1.12%	0.91%	0.93%	0.95%	1.14%	0.87%
Average Transmission O&M Loading	1.05%									

Source:
PacifiCorp FERC Form 1
Page 321, line 112
Page 321, line 96
Page 206-207, line 58

Distribution O&M Expense

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Distribution O&M Expense	69,136,197	61,535,374	61,513,756	61,139,370	68,212,991	83,124,296	90,983,613	114,178,049	176,892,710	211,065,153
Less:										
586 Meter Expense	2,616,262	1,645,292	1,079,103	883,546	655,758	1,279,281	1,305,324	1,394,304	1,150,746	1,404,932
587 Customer Installation Expense	4,157,616	5,227,622	5,089,251	5,107,333	5,763,027	6,702,788	6,553,641	6,997,994	6,808,979	6,693,168
597 Main. of Meters	1,198,881	10,098	59,787	85,408	231,001	235,870	158,233	185,682	167,740	115,609
Adjusted Distribution O&M Expense	61,163,438	54,652,362	55,285,614	55,063,083	61,563,205	74,906,357	82,966,414	105,600,068	168,765,245	202,851,444
Total Distribution Plant	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	2,640,927,937	2,981,612,553
Less:										
370 Meters	60,993,623	62,541,755	65,791,804	76,927,946	90,849,203	96,302,523	97,893,679	101,011,391	105,251,378	109,155,625
Adjusted Distribution Plant	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	2,535,676,559	2,872,456,928
Distribution O&M Loading	3.30%	2.86%	2.80%	2.68%	2.95%	3.38%	3.59%	4.38%	6.66%	7.06%
Average Distribution O&M Loading	3.97%									
Annualized Distribution O&M Loading Factor	49.99%									

Distribution Meter Expense

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
586 Meter Expense	2,616,262	1,645,292	1,079,103	883,546	655,758	1,279,281	1,305,324	1,394,304	1,150,746	1,404,932
597 Main. of Meters	1,198,881	10,098	59,787	85,408	231,001	235,870	158,233	185,682	167,740	115,609
Adjusted Distribution Meters Expense	3,815,143	1,655,390	1,138,890	968,955	886,759	1,515,150	1,463,558	1,579,986	1,318,486	1,520,540
370 Meters	60,993,623	62,541,755	65,791,804	76,927,946	90,849,203	96,302,523	97,893,679	101,011,391	105,251,378	109,155,625
Meter O&M Loading	6.25%	2.65%	1.73%	1.26%	0.98%	1.57%	1.50%	1.56%	1.25%	1.39%
Average Meter O&M Loading	2.01%									
Annualized Meter O&M Loading Factor	25.40%									

Source: FERC Form 1 (State of Oregon) & Results of Operations

Depreciation

Account Number	Description	6/30/2025 Balance	Iowa Curve	Average Life	Net Salvage Percent	Net Salvage Amount
		$		Yrs	%	$
350.2	Land Rights	375,056,914	R4	90.00	0.00%	-
352.0	Structures & Improvements	475,456,182	R2.5	75.00	-5.00%	(23,772,809)
353.0	Station Equipment	2,999,976,065	S0	60.00	-10.00%	(299,997,607)
353.7	Supervisory Equipment	-				-
354.0	Towers & Fixtures	2,589,458,008	R4	72.00	-8.00%	(207,156,641)
355.0	Poles & Fixtures	1,559,870,627	R2.5	62.00	-40.00%	(623,948,251)
356.0	OH Conductors & Devices	2,376,247,353	R2.5	68.00	-30.00%	(712,874,206)
356.2	Clearing	-				-
357.0	UG Conduit	3,924,286	S2.5	60.00	0.00%	-
358.0	UG Conductors & Devices	9,083,639	S2.5	60.00	-5.00%	(454,182)
359.0	Roads & Trails	12,141,468	R5	75.00	0.00%	-
	Total Transmission Plant	10,401,214,544		65.40	-17.96%	(1,868,203,695)
	Excluding land accounts:					
352.0	Structures & Improvements	475,456,182	2.5	4.74%	0.12	
353.0	Station Equipment	2,999,976,065		29.92%	-	
353.7	Supervisory Equipment	-		0.00%	-	
354.0	Towers & Fixtures	2,589,458,008	4.0	25.83%	1.03	
355.0	Poles & Fixtures	1,559,870,627	2.5	15.56%	0.39	
356.0	OH Conductors & Devices	2,376,247,353	2.5	23.70%	0.59	
356.2	Clearing	-		0.00%	-	
357.0	UG Conduit	3,924,286	2.5	0.04%	0.00	
358.0	UG Conductors & Devices	9,083,639	2.5	0.09%	0.00	
359.0	Roads & Trails	12,141,468	5.0	0.12%	0.01	
	Total Transmission Plant	10,026,157,629		100.00%	2.14	

Account Number	Description	6/30/2025 Balance	Iowa Curve	Average Life	Net Salvage Percent	Net Salvage Amount
		$		Yrs	%	$
360.2	Land Rights	6,478,895	S1.5	70.00	0.00%	-
361.0	Structures & Improvements	39,449,050	R2	67.00	-10.00%	(3,944,905)
362.0	Station Equipment	326,646,954	R1	53.00	-20.00%	(65,329,391)
362.7	Supervisory & Alarm Equipment					-
364.0	Poles, Towers & Fixtures	652,713,426	R1	58.00	-100.00%	(652,713,426)
365.0	OH Conductors & Devices	422,910,335	R1	65.00	-50.00%	(211,455,168)
366.0	UG Conduit	134,110,659	R3	75.00	-45.00%	(60,349,797)
367.0	UG Conductors & Devices	255,830,480	R2.5	60.00	-35.00%	(89,540,668)
368.0	Line Transformers	570,186,837	R1.5	46.00	-25.00%	(142,546,709)
369.1	Overhead Services	137,574,643	R2	60.00	-35.00%	(48,151,125)
369.2	Underground Services	256,399,008	R4	60.00	-40.00%	(102,559,603)
370.0	Meters	111,652,839	S3	20.00	-3.00%	(3,349,585)
371.0	I.O.C.P.	2,755,753	L0	27.00	-50.00%	(1,377,876)
373.0	Street Lighting & Signal Systems	25,386,390	R1	45.00	-30.00%	(7,615,917)
	Total Oregon Distribution Plant	2,942,095,270		53.60	-47.21%	(1,388,934,170)
	Excluding land accounts:					
361.0	Structures & Improvements	39,449,050	2.0	1.34%	0.03	
362.0	Station Equipment	326,646,954	1.0	11.13%	0.11	
362.7	Supervisory & Alarm Equipment	-		0.00%	-	
364.0	Poles, Towers & Fixtures	652,713,426	1.0	22.23%	0.22	
365.0	OH Conductors & Devices	422,910,335	1.0	14.41%	0.14	
366.0	UG Conduit	134,110,659	3.0	4.57%	0.14	
367.0	UG Conductors & Devices	255,830,480	2.5	8.71%	0.22	
368.0	Line Transformers	570,186,837	1.5	19.42%	0.29	
369.1	Overhead Services	137,574,643	2.0	4.69%	0.09	
369.2	Underground Services	256,399,008	4.0	8.73%	0.35	
370.0	Meters	111,652,839	3.0	3.80%	0.11	
371.0	I.O.C.P.	2,755,753		0.09%	-	
373.0	Street Lighting & Signal Systems	25,386,390	1.0	0.86%	0.01	
	Total OREGON Distribution Plant	2,935,616,375		100.00%	1.72	

Present Value of Cost of Dispersion (PVCD) Factor per Iowa Curve R 2.0 & 65 Year Average Life										
Year	PVCD	% Renewed	Num1	Dem1	Num1/Dem1	Num2	Dem2	Num2/Dem2	Instance	Iowa R 2.0
1	0.00071	7.82%	0.0782	1.05260	0.07425	0.0782	28.00309	0.00279	0.07146	99.9218
2	0.00207	15.63%	0.1563	1.10797	0.14108	0.1563	28.00309	0.00558	0.13549	99.7655
3	0.00335	15.63%	0.1563	1.16626	0.13403	0.1563	28.00309	0.00558	0.12844	99.6092
4	0.00463	16.32%	0.1632	1.22761	0.13297	0.1632	28.00309	0.00583	0.12714	99.4460
5	0.00598	18.40%	0.1840	1.29218	0.14239	0.1840	28.00309	0.00657	0.13582	99.2620
6	0.00727	18.40%	0.1840	1.36015	0.13528	0.1840	28.00309	0.00657	0.12871	99.0780
7	0.00849	18.40%	0.1840	1.43170	0.12852	0.1840	28.00309	0.00657	0.12195	98.8940
8	0.00985	21.60%	0.2160	1.50702	0.14333	0.2160	28.00309	0.00771	0.13562	98.6780
9	0.01113	21.60%	0.2160	1.58629	0.13617	0.2160	28.00309	0.00771	0.12845	98.4620
10	0.01235	21.60%	0.2160	1.66973	0.12936	0.2160	28.00309	0.00771	0.12165	98.2460
11	0.01364	24.28%	0.2428	1.75757	0.13813	0.2428	28.00309	0.00867	0.12946	98.0032
12	0.01491	25.17%	0.2517	1.85002	0.13605	0.2517	28.00309	0.00899	0.12706	97.7515
13	0.01612	25.17%	0.2517	1.94734	0.12925	0.2517	28.00309	0.00899	0.12026	97.4998
14	0.01734	27.18%	0.2718	2.04977	0.13262	0.2718	28.00309	0.00971	0.12291	97.2280
15	0.01859	29.20%	0.2920	2.15760	0.13534	0.2920	28.00309	0.01043	0.12491	96.9360
16	0.01977	29.20%	0.2920	2.27109	0.12857	0.2920	28.00309	0.01043	0.11814	96.6440
17	0.02094	30.33%	0.3033	2.39056	0.12688	0.3033	28.00309	0.01083	0.11605	96.3407
18	0.02215	33.72%	0.3372	2.51631	0.13402	0.3372	28.00309	0.01204	0.12198	96.0035
19	0.02331	33.72%	0.3372	2.64868	0.12732	0.3372	28.00309	0.01204	0.11528	95.6662
20	0.02440	33.72%	0.3372	2.78801	0.12096	0.3372	28.00309	0.01204	0.10891	95.3290
21	0.02558	38.71%	0.3871	2.93467	0.13190	0.3871	28.00309	0.01382	0.11808	94.9419
22	0.02669	38.71%	0.3871	3.08904	0.12531	0.3871	28.00309	0.01382	0.11148	94.5548
23	0.02774	38.71%	0.3871	3.25153	0.11904	0.3871	28.00309	0.01382	0.10522	94.1678
24	0.02885	42.91%	0.4291	3.42257	0.12537	0.4291	28.00309	0.01532	0.11004	93.7387
25	0.02992	44.31%	0.4431	3.60261	0.12299	0.4431	28.00309	0.01582	0.10717	93.2956
26	0.03093	44.31%	0.4431	3.79212	0.11684	0.4431	28.00309	0.01582	0.10102	92.8525
27	0.03195	47.40%	0.4740	3.99160	0.11875	0.4740	28.00309	0.01693	0.10182	92.3785
28	0.03297	50.49%	0.5049	4.20157	0.12017	0.5049	28.00309	0.01803	0.10214	91.8736
29	0.03393	50.49%	0.5049	4.42259	0.11417	0.5049	28.00309	0.01803	0.09614	91.3687
30	0.03486	52.20%	0.5220	4.65523	0.11213	0.5220	28.00309	0.01864	0.09349	90.8467
31	0.03583	57.32%	0.5732	4.90011	0.11698	0.5732	28.00309	0.02047	0.09651	90.2735
32	0.03673	57.32%	0.5732	5.15787	0.11114	0.5732	28.00309	0.02047	0.09067	89.7002
33	0.03759	57.32%	0.5732	5.42919	0.10558	0.5732	28.00309	0.02047	0.08511	89.1270
34	0.03849	64.83%	0.6483	5.71479	0.11344	0.6483	28.00309	0.02315	0.09029	88.4787
35	0.03934	64.83%	0.6483	6.01540	0.10777	0.6483	28.00309	0.02315	0.08462	87.8304
36	0.04013	64.83%	0.6483	6.33183	0.10239	0.6483	28.00309	0.02315	0.07924	87.1821
37	0.04094	70.97%	0.7097	6.66491	0.10648	0.7097	28.00309	0.02534	0.08114	86.4724
38	0.04172	73.02%	0.7302	7.01550	0.10408	0.7302	28.00309	0.02607	0.07800	85.7422
39	0.04245	73.02%	0.7302	7.38454	0.09888	0.7302	28.00309	0.02607	0.07280	85.0121
40	0.04317	77.46%	0.7746	7.77299	0.09965	0.7746	28.00309	0.02766	0.07199	84.2375
41	0.04388	81.91%	0.8191	8.18188	0.10011	0.8191	28.00309	0.02925	0.07086	83.4184
42	0.04453	81.91%	0.8191	8.61227	0.09511	0.8191	28.00309	0.02925	0.06586	82.5993
43	0.04516	84.31%	0.8431	9.06530	0.09300	0.8431	28.00309	0.03011	0.06289	81.7562
44	0.04580	91.51%	0.9151	9.54217	0.09590	0.9151	28.00309	0.03268	0.06322	80.8412
45	0.04638	91.51%	0.9151	10.04412	0.09111	0.9151	28.00309	0.03268	0.05843	79.9261
46	0.04692	91.51%	0.9151	10.57247	0.08655	0.9151	28.00309	0.03268	0.05388	79.0110
47	0.04747	101.66%	1.0166	11.12862	0.09135	1.0166	28.00309	0.03630	0.05505	77.9944
48	0.04797	101.66%	1.0166	11.71402	0.08679	1.0166	28.00309	0.03630	0.05048	76.9778
49	0.04843	101.66%	1.0166	12.33021	0.08245	1.0166	28.00309	0.03630	0.04615	75.9612
50	0.04889	109.65%	1.0965	12.97882	0.08448	1.0965	28.00309	0.03916	0.04533	74.8647
51	0.04931	112.31%	1.1231	13.66155	0.08221	1.1231	28.00309	0.04011	0.04210	73.7416
52	0.04969	112.31%	1.1231	14.38019	0.07810	1.1231	28.00309	0.04011	0.03799	72.6185
53	0.05005	117.74%	1.1774	15.13664	0.07778	1.1774	28.00309	0.04204	0.03574	71.4412
54	0.05038	123.17%	1.2317	15.93287	0.07731	1.2317	28.00309	0.04398	0.03332	70.2095
55	0.05067	123.17%	1.2317	16.77100	0.07344	1.2317	28.00309	0.04398	0.02946	68.9778
56	0.05094	125.87%	1.2587	17.65320	0.07130	1.2587	28.00309	0.04495	0.02635	67.7191
57	0.05118	133.97%	1.3397	18.58182	0.07210	1.3397	28.00309	0.04784	0.02426	66.3794
58	0.05139	133.97%	1.3397	19.55928	0.06849	1.3397	28.00309	0.04784	0.02065	65.0397
59	0.05156	133.97%	1.3397	20.58817	0.06507	1.3397	28.00309	0.04784	0.01723	63.7000
60	0.05171	144.25%	1.4425	21.67117	0.06656	1.4425	28.00309	0.05151	0.01505	62.2575
61	0.05183	144.25%	1.4425	22.81114	0.06323	1.4425	28.00309	0.05151	0.01172	60.8151
62	0.05191	144.25%	1.4425	24.01109	0.06007	1.4425	28.00309	0.05151	0.00856	59.3726
63	0.05197	151.15%	1.5115	25.27415	0.05980	1.5115	28.00309	0.05397	0.00583	57.8612
64	0.05200	153.45%	1.5345	26.60365	0.05768	1.5345	28.00309	0.05480	0.00288	56.3267
65	0.05200	153.45%	1.5345	28.00309	0.05480	1.5345	28.00309	0.05480	-	54.7922
66	0.05197	157.20%	1.5720	29.47614	0.05333	1.5720	28.00309	0.05614	(0.00281)	53.2202
67	0.05192	160.95%	1.6095	31.02668	0.05188	1.6095	28.00309	0.05748	(0.00560)	51.6107
68	0.05183	160.95%	1.6095	32.65879	0.04928	1.6095	28.00309	0.05748	(0.00819)	50.0012
69	0.05173	162.24%	1.6224	34.37674	0.04719	1.6224	28.00309	0.05794	(0.01074)	48.3788
70	0.05159	166.09%	1.6609	36.18507	0.04590	1.6609	28.00309	0.05931	(0.01341)	46.7178
71	0.05144	166.09%	1.6609	38.08852	0.04361	1.6609	28.00309	0.05931	(0.01571)	45.0569
72	0.05126	166.09%	1.6609	40.09210	0.04143	1.6609	28.00309	0.05931	(0.01788)	43.3960
73	0.05105	168.18%	1.6818	42.20108	0.03985	1.6818	28.00309	0.06006	(0.02021)	41.7142
74	0.05083	168.18%	1.6818	44.42099	0.03786	1.6818	28.00309	0.06006	(0.02220)	40.0323
75	0.05059	168.18%	1.6818	46.75768	0.03597	1.6818	28.00309	0.06006	(0.02409)	38.3505
76	0.05033	167.10%	1.6710	49.21729	0.03395	1.6710	28.00309	0.05967	(0.02572)	36.6795
77	0.05006	166.74%	1.6674	51.80628	0.03218	1.6674	28.00309	0.05954	(0.02736)	35.0121
78	0.04977	166.74%	1.6674	54.53146	0.03058	1.6674	28.00309	0.05954	(0.02897)	33.3447
79	0.04947	164.06%	1.6406	57.39999	0.02858	1.6406	28.00309	0.05859	(0.03000)	31.7041
80	0.04916	161.38%	1.6138	60.41941	0.02671	1.6138	28.00309	0.05763	(0.03092)	30.0902
81	0.04884	161.38%	1.6138	63.59767	0.02538	1.6138	28.00309	0.05763	(0.03226)	28.4764
82	0.04851	159.09%	1.5909	66.94311	0.02377	1.5909	28.00309	0.05681	(0.03305)	26.8855
83	0.04818	152.22%	1.5222	70.46454	0.02160	1.5222	28.00309	0.05436	(0.03275)	25.3633
84	0.04784	152.22%	1.5222	74.17120	0.02052	1.5222	28.00309	0.05436	(0.03383)	23.8412

85	0.04749	152.22%	1.5222	78.07285	0.01950	1.5222	28.00309	0.05436	(0.03486)	22.3190
86	0.04717	139.60%	1.3960	82.17974	0.01699	1.3960	28.00309	0.04985	(0.03286)	20.9230
87	0.04683	139.60%	1.3960	86.50266	0.01614	1.3960	28.00309	0.04985	(0.03371)	19.5270
88	0.04648	139.60%	1.3960	91.05298	0.01533	1.3960	28.00309	0.04985	(0.03452)	18.1310
89	0.04616	128.13%	1.2813	95.84266	0.01337	1.2813	28.00309	0.04576	(0.03239)	16.8497
90	0.04584	124.31%	1.2431	100.88430	0.01232	1.2431	28.00309	0.04439	(0.03207)	15.6066
91	0.04551	124.31%	1.2431	106.19114	0.01171	1.2431	28.00309	0.04439	(0.03268)	14.3635
92	0.04520	115.85%	1.1585	111.77714	0.01036	1.1585	28.00309	0.04137	(0.03101)	13.2051
93	0.04491	107.38%	1.0738	117.65698	0.00913	1.0738	28.00309	0.03835	(0.02922)	12.1312
94	0.04461	107.38%	1.0738	123.84612	0.00867	1.0738	28.00309	0.03835	(0.02968)	11.0574
95	0.04432	103.02%	1.0302	130.36082	0.00790	1.0302	28.00309	0.03679	(0.02889)	10.0272
96	0.04407	89.94%	0.8994	137.21823	0.00655	0.8994	28.00309	0.03212	(0.02556)	9.1278
97	0.04381	89.94%	0.8994	144.43635	0.00623	0.8994	28.00309	0.03212	(0.02589)	8.2284
98	0.04355	89.94%	0.8994	152.03417	0.00592	0.8994	28.00309	0.03212	(0.02620)	7.3290
99	0.04333	72.86%	0.7286	160.03166	0.00455	0.7286	28.00309	0.02602	(0.02147)	6.6004
100	0.04312	72.86%	0.7286	168.44985	0.00433	0.7286	28.00309	0.02602	(0.02169)	5.8718
101	0.04290	72.86%	0.7286	177.31086	0.00411	0.7286	28.00309	0.02602	(0.02191)	5.1432
102	0.04271	60.84%	0.6084	186.63799	0.00326	0.6084	28.00309	0.02173	(0.01847)	4.5348
103	0.04254	56.83%	0.5683	196.45575	0.00289	0.5683	28.00309	0.02029	(0.01740)	3.9665
104	0.04236	56.83%	0.5683	206.78996	0.00275	0.5683	28.00309	0.02029	(0.01755)	3.3982
105	0.04221	49.42%	0.4942	217.66778	0.00227	0.4942	28.00309	0.01765	(0.01538)	2.9040
106	0.04208	42.00%	0.4200	229.11782	0.00183	0.4200	28.00309	0.01500	(0.01317)	2.4840
107	0.04194	42.00%	0.4200	241.17016	0.00174	0.4200	28.00309	0.01500	(0.01326)	2.0640
108	0.04182	38.63%	0.3863	253.85649	0.00152	0.3863	28.00309	0.01380	(0.01227)	1.6777
109	0.04173	28.52%	0.2852	267.21017	0.00107	0.2852	28.00309	0.01019	(0.00912)	1.3925
110	0.04164	28.52%	0.2852	281.26629	0.00101	0.2852	28.00309	0.01019	(0.00917)	1.1072
111	0.04155	28.52%	0.2852	296.06181	0.00096	0.2852	28.00309	0.01019	(0.00922)	0.8220
112	0.04149	16.68%	0.1668	311.63563	0.00054	0.1668	28.00309	0.00596	(0.00542)	0.6552
113	0.04144	16.68%	0.1668	328.02867	0.00051	0.1668	28.00309	0.00596	(0.00545)	0.4885
114	0.04138	16.68%	0.1668	345.28405	0.00048	0.1668	28.00309	0.00596	(0.00547)	0.3217
115	0.04135	9.57%	0.0957	363.44711	0.00026	0.0957	28.00309	0.00342	(0.00315)	0.2260
116	0.04133	7.20%	0.0720	382.56561	0.00019	0.0720	28.00309	0.00257	(0.00238)	0.1540
117	0.04130	7.20%	0.0720	402.68980	0.00018	0.0720	28.00309	0.00257	(0.00239)	0.0820
118	0.04129	4.31%	0.0431	423.87260	0.00010	0.0431	28.00309	0.00154	(0.00144)	0.0389
119	0.04128	1.42%	0.0142	446.16967	0.00003	0.0142	28.00309	0.00051	(0.00047)	0.0248
120	0.04128	1.42%	0.0142	469.63965	0.00003	0.0142	28.00309	0.00051	(0.00048)	0.0106
121	0.04128	1.06%	0.0106	494.34422	0.00002	0.0106	28.00309	0.00038	(0.00036)	-

Present Value of Cost of Dispersion (PVCD) Factor per Iowa Curve R 2.0 & 54 Year Average Life										
Year	PVCD	% Renewed	Num1	Dem1	Num1/Dem1	Num2	Dem2	Num2/Dem2	Instance	Iowa R 2.0
1	0.00083	9.41%	0.0941	1.05260	0.08937	0.0941	15.93287	0.00590	0.08347	99.9059
2	0.00241	18.81%	0.1881	1.10797	0.16981	0.1881	15.93287	0.01181	0.15800	99.7178
3	0.00391	18.81%	0.1881	1.16626	0.16133	0.1881	15.93287	0.01181	0.14952	99.5296
4	0.00552	21.48%	0.2148	1.22761	0.17499	0.2148	15.93287	0.01348	0.16150	99.3148
5	0.00710	22.15%	0.2215	1.29218	0.17140	0.2215	15.93287	0.01390	0.15750	99.0933
6	0.00862	22.53%	0.2253	1.36015	0.16567	0.2253	15.93287	0.01414	0.15152	98.8680
7	0.01027	26.00%	0.2600	1.43170	0.18160	0.2600	15.93287	0.01632	0.16528	98.6080
8	0.01183	26.00%	0.2600	1.50702	0.17253	0.2600	15.93287	0.01632	0.15621	98.3480
9	0.01340	27.72%	0.2772	1.58629	0.17474	0.2772	15.93287	0.01740	0.15734	98.0708
10	0.01503	30.30%	0.3030	1.66973	0.18144	0.3030	15.93287	0.01901	0.16243	97.7679
11	0.01656	30.30%	0.3030	1.75757	0.17238	0.3030	15.93287	0.01901	0.15336	97.4649
12	0.01817	33.69%	0.3369	1.85002	0.18212	0.3369	15.93287	0.02115	0.16097	97.1280
13	0.01976	35.15%	0.3515	1.94734	0.18049	0.3515	15.93287	0.02206	0.15843	96.7765
14	0.02125	35.15%	0.3515	2.04977	0.17147	0.3515	15.93287	0.02206	0.14941	96.4250
15	0.02288	40.59%	0.4059	2.15760	0.18814	0.4059	15.93287	0.02548	0.16266	96.0191
16	0.02441	40.59%	0.4059	2.27109	0.17874	0.4059	15.93287	0.02548	0.15326	95.6131
17	0.02592	42.39%	0.4239	2.39056	0.17733	0.4239	15.93287	0.02661	0.15073	95.1892
18	0.02748	46.59%	0.4659	2.51631	0.18516	0.4659	15.93287	0.02924	0.15592	94.7233
19	0.02894	46.59%	0.4659	2.64868	0.17591	0.4659	15.93287	0.02924	0.14667	94.2574
20	0.03044	50.64%	0.5064	2.78801	0.18162	0.5064	15.93287	0.03178	0.14984	93.7510
21	0.03192	53.33%	0.5333	2.93467	0.18174	0.5333	15.93287	0.03347	0.14826	93.2177
22	0.03331	53.33%	0.5333	3.08904	0.17265	0.5333	15.93287	0.03347	0.13918	92.6843
23	0.03478	60.03%	0.6003	3.25153	0.18463	0.6003	15.93287	0.03768	0.14695	92.0840
24	0.03618	60.78%	0.6078	3.42257	0.17758	0.6078	15.93287	0.03815	0.13943	91.4762
25	0.03752	62.42%	0.6242	3.60261	0.17327	0.6242	15.93287	0.03918	0.13409	90.8520
26	0.03891	69.00%	0.6900	3.79212	0.18196	0.6900	15.93287	0.04331	0.13865	90.1620
27	0.04020	69.00%	0.6900	3.99160	0.17286	0.6900	15.93287	0.04331	0.12956	89.4720
28	0.04149	73.52%	0.7352	4.20157	0.17498	0.7352	15.93287	0.04614	0.12884	88.7368
29	0.04276	78.04%	0.7804	4.42259	0.17645	0.7804	15.93287	0.04898	0.12747	87.9564
30	0.04395	78.04%	0.7804	4.65523	0.16763	0.7804	15.93287	0.04898	0.11865	87.1761
31	0.04517	85.92%	0.8592	4.90011	0.17534	0.8592	15.93287	0.05393	0.12141	86.3169
32	0.04632	87.89%	0.8789	5.15787	0.17040	0.8789	15.93287	0.05516	0.11524	85.4380
33	0.04740	88.96%	0.8896	5.42919	0.16385	0.8896	15.93287	0.05583	0.10802	84.5484
34	0.04850	98.59%	0.9859	5.71479	0.17252	0.9859	15.93287	0.06188	0.11064	83.5625
35	0.04952	98.59%	0.9859	6.01540	0.16390	0.9859	15.93287	0.06188	0.10202	82.5766
36	0.05051	103.21%	1.0321	6.33183	0.16301	1.0321	15.93287	0.06478	0.09823	81.5444
37	0.05147	110.15%	1.1015	6.66491	0.16527	1.1015	15.93287	0.06913	0.09613	80.4429
38	0.05235	110.15%	1.1015	7.01550	0.15701	1.1015	15.93287	0.06913	0.08787	79.3414
39	0.05321	118.70%	1.1870	7.38454	0.16075	1.1870	15.93287	0.07450	0.08624	78.1544
40	0.05402	122.37%	1.2237	7.77299	0.15743	1.2237	15.93287	0.07680	0.08063	76.9307
41	0.05474	122.37%	1.2237	8.18188	0.14956	1.2237	15.93287	0.07680	0.07276	75.7070
42	0.05546	135.19%	1.3519	8.61227	0.15697	1.3519	15.93287	0.08485	0.07212	74.3551
43	0.05611	135.19%	1.3519	9.06530	0.14912	1.3519	15.93287	0.08485	0.06428	73.0033
44	0.05669	139.11%	1.3911	9.54217	0.14578	1.3911	15.93287	0.08731	0.05847	71.6122
45	0.05724	148.26%	1.4826	10.04412	0.14761	1.4826	15.93287	0.09305	0.05456	70.1296
46	0.05771	148.26%	1.4826	10.57247	0.14023	1.4826	15.93287	0.09305	0.04718	68.6470
47	0.05813	156.06%	1.5606	11.12862	0.14023	1.5606	15.93287	0.09795	0.04228	67.0864
48	0.05850	161.26%	1.6126	11.71402	0.13766	1.6126	15.93287	0.10121	0.03645	65.4739
49	0.05879	161.26%	1.6126	12.33021	0.13078	1.6126	15.93287	0.10121	0.02957	63.8613
50	0.05904	172.39%	1.7239	12.97882	0.13283	1.7239	15.93287	0.10820	0.02463	62.1373
51	0.05922	173.63%	1.7363	13.66155	0.12709	1.7363	15.93287	0.10898	0.01812	60.4010
52	0.05934	175.84%	1.7584	14.38019	0.12228	1.7584	15.93287	0.11037	0.01192	58.6426
53	0.05940	184.70%	1.8470	15.13664	0.12202	1.8470	15.93287	0.11593	0.00610	56.7956
54	0.05940	184.70%	1.8470	15.93287	0.11593	1.8470	15.93287	0.11593	-	54.9485
55	0.05934	189.22%	1.8922	16.77100	0.11283	1.8922	15.93287	0.11876	(0.00594)	53.0563
56	0.05922	193.74%	1.9374	17.65320	0.10975	1.9374	15.93287	0.12160	(0.01185)	51.1189
57	0.05905	193.74%	1.9374	18.58182	0.10426	1.9374	15.93287	0.12160	(0.01733)	49.1815
58	0.05882	198.69%	1.9869	19.55928	0.10158	1.9869	15.93287	0.12470	(0.02312)	47.1946
59	0.05853	199.93%	1.9993	20.58817	0.09711	1.9993	15.93287	0.12548	(0.02837)	45.1953
60	0.05820	200.18%	2.0018	21.67117	0.09237	2.0018	15.93287	0.12564	(0.03327)	43.1936
61	0.05782	202.44%	2.0244	22.81114	0.08875	2.0244	15.93287	0.12706	(0.03831)	41.1691
62	0.05739	202.44%	2.0244	24.01109	0.08431	2.0244	15.93287	0.12706	(0.04275)	39.1447
63	0.05692	201.75%	2.0175	25.27415	0.07982	2.0175	15.93287	0.12662	(0.04680)	37.1272
64	0.05642	200.70%	2.0070	26.60365	0.07544	2.0070	15.93287	0.12597	(0.05053)	35.1201
65	0.05587	200.70%	2.0070	28.00309	0.07167	2.0070	15.93287	0.12597	(0.05430)	33.1131
66	0.05531	196.19%	1.9619	29.47614	0.06656	1.9619	15.93287	0.12314	(0.05658)	31.1512
67	0.05472	194.26%	1.9426	31.02668	0.06261	1.9426	15.93287	0.12192	(0.05931)	29.2086
68	0.05409	194.26%	1.9426	32.65879	0.05948	1.9426	15.93287	0.12192	(0.06244)	27.2660
69	0.05347	183.22%	1.8322	34.37674	0.05330	1.8322	15.93287	0.11500	(0.06170)	25.4338
70	0.05283	183.22%	1.8322	36.18507	0.05063	1.8322	15.93287	0.11500	(0.06436)	23.6016
71	0.05218	178.67%	1.7867	38.08852	0.04691	1.7867	15.93287	0.11214	(0.06523)	21.8149
72	0.05154	168.04%	1.6804	40.09210	0.04191	1.6804	15.93287	0.10547	(0.06355)	20.1345
73	0.05089	168.04%	1.6804	42.20108	0.03982	1.6804	15.93287	0.10547	(0.06565)	18.4541
74	0.05025	156.99%	1.5699	44.42099	0.03534	1.5699	15.93287	0.09853	(0.06319)	16.8842
75	0.04964	149.63%	1.4963	46.75768	0.03200	1.4963	15.93287	0.09391	(0.06191)	15.3879
76	0.04900	149.63%	1.4963	49.21729	0.03040	1.4963	15.93287	0.09391	(0.06351)	13.8916
77	0.04843	131.30%	1.3130	51.80628	0.02534	1.3130	15.93287	0.08241	(0.05706)	12.5787
78	0.04786	129.26%	1.2926	54.53146	0.02370	1.2926	15.93287	0.08113	(0.05742)	11.2861
79	0.04729	125.06%	1.2506	57.39999	0.02179	1.2506	15.93287	0.07849	(0.05670)	10.0355
80	0.04679	108.26%	1.0826	60.41941	0.01792	1.0826	15.93287	0.06795	(0.05003)	8.9529
81	0.04628	108.26%	1.0826	63.59767	0.01702	1.0826	15.93287	0.06795	(0.05092)	7.8703
82	0.04581	97.98%	0.9798	66.94311	0.01464	0.9798	15.93287	0.06150	(0.04686)	6.8905
83	0.04538	87.70%	0.8770	70.46454	0.01245	0.8770	15.93287	0.05505	(0.04260)	6.0134
84	0.04495	87.70%	0.8770	74.17120	0.01182	0.8770	15.93287	0.05505	(0.04322)	5.1364

85	0.04459	72.27%	0.7227	78.07285	0.00926	0.7227	15.93287	0.04536	(0.03610)	4.4137
86	0.04424	68.41%	0.6841	82.17974	0.00832	0.6841	15.93287	0.04293	(0.03461)	3.7297
87	0.04390	66.62%	0.6662	86.50266	0.00770	0.6662	15.93287	0.04181	(0.03411)	3.0634
88	0.04364	50.56%	0.5056	91.05298	0.00555	0.5056	15.93287	0.03173	(0.02618)	2.5579
89	0.04338	50.56%	0.5056	95.84266	0.00527	0.5056	15.93287	0.03173	(0.02646)	2.0523
90	0.04314	44.07%	0.4407	100.88430	0.00437	0.4407	15.93287	0.02766	(0.02329)	1.6117
91	0.04296	34.33%	0.3433	106.19114	0.00323	0.3433	15.93287	0.02155	(0.01832)	1.2683
92	0.04278	34.33%	0.3433	111.77714	0.00307	0.3433	15.93287	0.02155	(0.01848)	0.9250
93	0.04264	24.35%	0.2435	117.65698	0.00207	0.2435	15.93287	0.01528	(0.01321)	0.6815
94	0.04253	20.07%	0.2007	123.84612	0.00162	0.2007	15.93287	0.01260	(0.01098)	0.4807
95	0.04242	20.07%	0.2007	130.36082	0.00154	0.2007	15.93287	0.01260	(0.01106)	0.2800
96	0.04238	8.67%	0.0867	137.21823	0.00063	0.0867	15.93287	0.00544	(0.00481)	0.1933
97	0.04233	8.67%	0.0867	144.43635	0.00060	0.0867	15.93287	0.00544	(0.00484)	0.1067
98	0.04229	6.58%	0.0658	152.03417	0.00043	0.0658	15.93287	0.00413	(0.00370)	0.0409
99	0.04228	1.70%	0.0170	160.03166	0.00011	0.0170	15.93287	0.00107	(0.00096)	0.0239
100	0.04227	1.70%	0.0170	168.44985	0.00010	0.0170	15.93287	0.00107	(0.00097)	0.0068
101	0.04227	0.68%	0.0068	177.31086	0.00004	0.0068	15.93287	0.00043	(0.00039)	-

Docket No. UE 470
Exhibit PAC/908
Witness: Kenneth Lee Elder, Jr.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Kenneth Lee Elder, Jr.

Residential Basic Charge Calculation

May 2026

Residential Basic Charge Calculation
20 Year Residential Marginal Unit Costs
December 2027 Dollars per Customer per Year

	All Residential	Single Family	Multi-Family
Poles	$110.52	$127.75	$46.66
Conductor	$53.98	$62.39	$22.79
Transformers	$137.75	$175.65	$50.83
Service Drop	$97.15	$97.15	$97.15
Meters	$24.01	$24.01	$24.01
Billing & Collections	$21.96	$21.96	$21.96
Uncollectables	$14.37	$14.37	$14.37
Customer Service / Other	$10.89	$10.89	$10.89
Total per Year	$470.62	$534.17	$288.65
Total per Month	$39.22	**$44.51**	**$24.05**
Current Basic Charge		$14.00	$8.00
Proposed Basic Charge		**$17.00**	**$9.00**

Docket No. UE 470
Exhibit PAC/1000
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

May 2026

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ATTACHED EXHIBITS

Exhibit PAC/1001—Summary of Proposed Rate Changes in this General Rate Case and Summary of Proposed Rate Changes Including TAM and PCAM Rate Cancellations

Exhibit PAC/1002—Proposed Interim Rate Adjustment, Interim Tariffs and Estimated Effect of Proposed Interim Rate Adjustment

Exhibit PAC/1003—Proposed General Rate Case Tariffs

Exhibit PAC/1004—Target Functionalized Revenues, Billing Determinants and Proposed Base Rates

Exhibit PAC/1005—Estimated Effect of Proposed Price Changes and Monthly Billing Comparisons

Exhibit PAC/1006—Proposed Adjustment Schedule Calculations

Exhibit PAC/1007—Proposed Adjustments Related to the Washington Service Area Transfer

Exhibit PAC/1008—Calculation of Proposed Schedule 300 Facilities Charges

Exhibit PAC/1009—Cumulative Economic Impact Analysis

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power.

A. My name is Judith M. Ridenour. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My current position is Specialist, Pricing and Cost of Service, in the regulation department.

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Arts degree in Mathematics from Reed College. I joined the company in the regulation department in October 2000. I assumed my present responsibilities in May 2001. In my current position, I am responsible for the preparation of rate design used in retail price filings and related analyses. Since 2001, with levels of increasing responsibility, I have analyzed and implemented rate design proposals throughout the company's six-state service territory.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What are your responsibilities in these proceedings?

A. I am responsible for the design of the company's proposed prices in this proceeding. I present the company's proposed rate spread, rates, and tariffs, and the impacts of the proposed rate changes on customers. I also present the newly required cumulative economic impact analysis.

Q. Please summarize your testimony.

A. The overall rate increase proposed by PacifiCorp in this case, including the effect of proposed changes to adjustment schedules related to wildfire mitigation, deferred insurance premiums and renewable resource deferred amounts but excluding the

proposed changes related to the transfer of the company's Washington service area, is $170.7 million or 8.6 percent. The company is proposing a base rate spread that is consistent with the cost-of-service study in this case. PacifiCorp's net rate spread proposes continued use of the Rate Mitigation Adjustment (RMA) to achieve a rate increase where no customer rate class will see a rate increase more than 10.8 percent.

PacifiCorp proposes to implement an interim rate increase of $55.1 million or 2.8 percent to take place 30 days after the filing of this case, June 4, 2026, subject to refund. This requested increase is the same percentage as the percentage reduction for residential customers recently implemented on May 1, 2026, to cancel the company's Power Cost Adjustment Mechanism (PCAM) rate recovering amounts related to 2022 deferred net power costs (NPC). Consistent with Oregon Revised Statute (ORS) § 757.215(5), the company proposes to maintain the revenue relationships among customer classes and between the revenues derived from demand charges and from energy charges by implementing this interim increase through a percentage surcharge applied to customer bills. PacifiCorp proposes that this surcharge will be canceled at such time as the main rate change in this case takes effect, expected to be July 15, 2027. If the interim increase is approved, the incremental impact to customers of the general rate case in 2027 would be an increase of $115.6 million or 5.7 percent. With the proposed RMA, no customer class will see an increase from the incremental general rate case more than 7.7 percent.

The company proposes two adjustments to deal with the pending sale of PacifiCorp's Washington service area and certain Washington-based assets to Gem Sub LLC, an affiliate of Portland General Electric Company (Service Area Transfer).

One adjustment will collect the increased revenue requirement from Oregon customers due to the change in allocations with the state of Washington removed. The other adjustment is a credit to Oregon customers passing back a portion of the benefits of the sale to customers as an outcome of the Service Area Transfer. Both of these adjustments would become effective at the same time as the main changes proposed in this case or on the date the Service Area Transfer transaction closes, whichever comes later. The incremental impact of these two adjustments would be a small overall increase of $3.0 million or 0.1 percent.

For rate design, the company largely proposes applying the price change to each rate in accordance with the functionalized change indicated by the cost of service study for each class of customers in the study. For residential customers, the company proposes increasing the single-family basic charge from $14 to $17 per month and the multi-family basic charge from $8 to $9.

The company proposes a periodic update to Schedule 300 facilities charges related to line extension requests based on the most current available inputs.

Finally, the company provides the cumulative economic impact analysis required by the new Oregon Administrative Rule (OAR) 860-022-0500.

Q. Have you prepared an exhibit which summarizes the rate impacts proposed by the company in this docket?

A. Yes. The table on page 1 of Exhibit PAC/1001 summarizes the three-part rate change proposed by the company in this docket: the interim change, the incremental general rate case change, and the Service Area Transfer change. These impacts are also provided in separate rate impact tables later in my testimony.

Q. What are the impacts to the average single-family and multi-family residential customer of the proposed rate changes in this docket?

A. The average residential customer living in a single-family dwelling using 900 kilowatt-hours per month will see a bill increase of $4.01 per month from the interim increase and an additional $11.60 per month from the final rate change in this case. This customer also would see an additional $0.82 per month increase from the Service Area Transfer. The average residential customer living in a multi-family dwelling using 550 kilowatt-hours per month will see a bill increase of $2.43 per month from the interim increase and an additional $6.26 per month from the final rate change in this case. This customer would be subject to an additional $0.50 per month increase from the Service Area Transfer. These increases will be largely offset by other expected rate decreases as I describe next.

Q. What is shown in the table in Exhibit PAC/1001 page 2?

A. Exhibit PAC/1001 page 2 provides a summary of the impacts of the rate changes proposed in this case alongside the expected rate changes related to the falling off of the four PCAM amortization rates for 2021 through 2024 and company's pending Transition Adjustment Mechanism (TAM). The company's 2022 PCAM amortization rate was turned off on May 1, 2026, resulting in a 3.2 percent overall rate decrease and a 2.8 percent decrease for residential customers. The TAM is currently expected to result in a decrease of 2.8 percent to customers on January 1, 2027. The 2021, 2023, and 2024 PCAM amortizations are expected to end in early 2027 for an overall decrease of approximately 4.7 percent. The net result of these rate decreases when

combined with the proposed rate changes in this case is an overall decrease of about 2.1 percent.

Residential customers will see no overall increase from the combination of the end of the 2022 PCAM amortization and the interim increase. Combining the interim increase, the incremental general rate case increase- which is mitigated for residential customers as I describe later in my testimony- and the Service Area Transfer increase with the anticipated 2026 and 2027 TAM and PCAM related decreases, residential customers overall will see a modest combined 1.9 percent increase.

III. INTERIM RATE INCREASE

Q. How does the company propose to implement the proposed interim rate increase?

A. The company proposes to collect the $55.1 million interim rate increase through a percentage surcharge of 2.8 percent applied to all customers' net bills prior to the application of pass-through adjustments such as the Public Purpose Charge. This methodology applies the interim increase uniformly to all customers based on their share of present revenues. This proposal is consistent with ORS 757.215(5), which provides that any interim increase must be implemented through a rate design that increases the utility's revenues "without materially changing the revenue relationships among customer classes or between the revenues derived from demand charges and from energy charges." A percentage surcharge is the simplest method to maintain these relationships.

Q. Please describe Exhibit PAC/1002.

A. Exhibit PAC/1002 provides the calculation of the proposed interim surcharge of 2.8 percent, presents the proposed tariffs necessary to implement the interim

surcharge, and, finally, shows the rate impact of the interim rate change by rate schedule. The average residential customer living in a single-family dwelling using 900 kilowatt-hours per month will see a bill increase of $4.01 per month from the interim increase. The change for this customer from the May 1 PCAM change was a bill decrease of $4.03, which means the interim increase for this average customer will result in a bill at the same level it was before the May 1 decrease. The average residential customer living in a multi-family dwelling using 550 kilowatt-hours per month will see a bill increase of $2.43 per month from the interim increase. The change for this customer from the May 1 PCAM change was a bill decrease of $2.46, which means the interim increase for this average customer also will result in a bill at the same level it was before the May 1 decrease. Exhibit PAC/1005 presented later in my testimony shows the monthly billing effects of the interim rate increase on customers of various sizes served under the major delivery service schedules.

Q. How long will the proposed Interim Rate Adjustment be in effect?

A. The proposed Schedule 80 – Interim Rate Adjustment would remain in effect until the implementation of the final rate change in this docket, anticipated to be July 15, 2027. As part of the final compliance filing in this case, the company will propose to cancel the Interim Rate Adjustment tariff effective as of the final rate change effective date of this docket. If the Oregon Public Utility Commission (Commission) ultimately were to order a refund of any portion of the interim increase, the company proposes instead to reset the Schedule 80 rate as a credit to pass required amounts back to customers over one year.

IV. PROPOSED TARIFFS

Q. Have you prepared an exhibit with the proposed tariffs to implement the main rate changes proposed in this proceeding?

A. Yes. Exhibit PAC/1003 contains the proposed tariffs for this general rate case proceeding and incorporates the main rate and tariff changes for the general rate case discussed in my testimony. Exhibit PAC/1003 also contains the proposed tariffs to implement the proposed surcharge and credit related to Service Area Transfer, discussed later in my testimony. These tariffs may ultimately have a different effective date than the final rate change in this docket; however, they are included within this exhibit for ease of presentation.

V. ALLOCATION OF THE FUNCTIONALIZED REVENUE REQUIREMENT

Q. How is the company proposing to allocate the functionalized revenue requirement across classes of customers in this proceeding?

A. The company is allocating the functionalized revenue requirement to classes consistent with the Commission's rules under OAR 860-038-0200 for Direct Access. These rules indicate that "rates for any class of consumer must be based on the unbundled costs to serve that class."[1] In this filing, the company has allocated the revenue requirement to each rate schedule based on the results of the functionalized class cost of service study. The proposed rates for each rate schedule included in the cost-of-service study are targeted to collect the cost of service for that rate schedule in the test period. Therefore, the proposed base rates for each class are based on the unbundled costs to serve that class.

[4] OAR 860-038-0240(3)(b).

Q. Do you have an exhibit that summarizes the functionalized results of the cost-of-service study?

A. Yes. Pages 1 and 2 of Exhibit PAC/1004 summarize the functionalized results of the cost-of-service study in column (4). This summary is provided at the level used to design rates. The cost of service for each rate schedule has been summarized into the following components: Transmission & Ancillary Services, System Usage, Distribution, Generation Energy Other Non-net Power Costs (Non-NPC), and Generation Energy NPC.

Q. What is the purpose of including this summary of cost components for the target functionalized revenue requirement?

A. The summary level for revenue requirement shown on pages 1 and 2 of Exhibit PAC/1004 summarizes the more granular cost-of-service results into the target revenue requirement components used in rate design.

The process of unbundling the company's proposed prices is consistent with the method the company first implemented in docket UE 116. For each rate schedule, the functionalized costs are applied to rates as follows: distribution, non-Federal Energy Regulatory Commission (FERC) transmission, billing, metering, and customer costs are included in each proposed delivery service schedule's Distribution rates; the FERC regulated transmission and ancillary services are included in each proposed delivery service schedule's Transmission & Ancillary Services rates; franchise fees are included in System Usage rates; non-NPC generation costs are included in Schedule 200, Base Supply Service rates; and NPC are included in Schedule 201, Net Power Costs, Cost-Based Supply Service rates.

Q. Have any adjustments been made to the functionalized revenue requirement by rate schedule resulting from the cost-of-service study?

A. Yes. Consistent with past cases, the functionalized revenue requirement has been adjusted to remove the proposed changes to NPC collected through Schedule 201. Changes to Schedule 201 are implemented through the TAM, which is a separate proceeding from this general rate case, and the Schedule 201 changes will be addressed in that proceeding. The modified cost of service results reflecting this adjustment to remove the NPC increase from the functionalized revenue requirement is shown in column (5) on pages 1 and 2 of Exhibit PAC/1004. This exhibit displays the target functionalized revenue requirement used in the design of rates proposed in this general rate case.

Q. Do the company's proposed rates collect the target functionalized revenues?

A. Yes. The revenues calculated by multiplying the test period billing determinants by the proposed rates are summarized in column (6) on pages 1 and 2 of Exhibit PAC/1004. A direct comparison to the target functionalized revenues shown in column (6) of this exhibit shows that the calculated revenues equal the target revenues with the exception of small differences due to the rounding of rates. The detailed calculation of proposed revenues based on billing determinants and proposed rates is shown on pages 3 through 11 of Exhibit PAC/1004.

Q. Have you prepared an exhibit showing the estimated effects of the prices proposed in this general rate case?

A. Yes. The first four pages of Exhibit PAC/1005 show the estimated effect of the company's proposed prices by delivery service rate schedule. It contains four

summary tables. Present revenues in Table 1005-1 assume the interim rate increase is approved, and the table shows the effect of the proposed prices for the incremental rate increase of $115.6 million or 5.7 percent overall. Table 1005-2 shows the full effect of the proposed general rate case prices from rates in effect today, an increase of 170.7 million or 8.6 percent overall. This would be the full impact of the general rate case if the interim rate increase step is not approved. Both these tables include the impacts of the proposed changes to adjustment schedules: $1.4 million additional for the Wildfire Mitigation Plan Cost Recovery Adjustment, $1.6 million additional for recovery of deferred amounts related to increased insurance premium costs, $6.0 million additional for the Renewable Resource Deferral Adjustment. The tables show the effect of the price changes on both base revenues and net revenues. Base revenues show the effect before the impacts of any adjustment tariffs. Net revenues include the effect of adjustment tariffs (discussed directly below) and the RMA.

The adder columns in Tables 1005-1 and 1005-2 show revenues from adjustment tariff schedules (Schedules 94, 190, 192, 203, 204, 206, 207, 291, and 299). Present adjustment schedules are shown in the present adders column, and proposed changes to adjustment schedules are reflected in the proposed adder column. The adder revenue is added to base revenue to get net revenue including adjustment schedules. Table 1005-3 shows the calculation of the present and proposed adjustment revenue shown in the adder columns in Tables 1005-1 and 1005-2. These adders exclude the effects of pass-through adjustment schedules for Low Income Bill Payment Assistance Charge (Schedule 91), the Low-Income Discount Cost Recovery Adjustment (Schedule 92), the Adjustment Associated with the Pacific Northwest

Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the Energy Trust of Oregon and Energy Efficiency Charge (Schedule 292). Table 1005-4 shows the present and proposed rates for each of the adjustment schedules.

Beginning on page 5 of Exhibit PAC/1005 are the monthly billing comparisons for each of the major delivery service rate schedules showing the customer bill impacts of the proposed prices at various levels of usage. The monthly billing comparisons include the effects of all adjustment schedules including the pass-through adjustment schedules listed above. Each page of the monthly billing comparisons in Exhibit PAC/1005 beginning on page 5 shows the estimated impact of the whole general rate case plus a break out of the anticipated two step impact of the interim rate increase and the incremental general rate case increase.

Q. What is the impact to the average single family and multi-family residential customer?

A. Table 1 below shows the two-step monthly interim/general rate case bill increase on the average single family and multi-family residential customer alongside the single step total general rate case increase with no interim increase.

Table 1

	Present Bill	Interim Increase	Incremental General Rate Case	Total General Rate Case	Proposed Bill
Single Family Dwelling (900 kWh per month)	$145.95	$4.01	$11.60	$15.61	$161.56
Multi-Family Dwelling (550 kWh per month)	$90.21	$2.43	$6.26	$8.69	$98.90

Q. Do the tables and calculations in Exhibit PAC/1005 include the impacts of the proposed rates related to the Service Area Transfer?

A. No. The impacts of the proposed rates related to the Service Area Transfer are not included in Exhibit PAC/1005. The impacts of those proposed changes are shown in a separate exhibit, discussed later in my testimony.

Q. What are the company's rate spread objectives in this case?

A. The company's rate spread objectives in this case are to minimize price impacts on customers while fairly reflecting cost of service and sending proper signals about increasing costs.

Q. What is the company's rate spread proposal in this case?

A. Table 2 below summarizes the company's proposed net percentage price changes of the interim increase and the incremental general rate case increase (labeled as "Incremental GRC" in the table), including the impact of proposed updated adjustment schedules, for the major rate schedule classes.

Table 2

Customer Type	Interim	Incremental GRC
Residential Schedule 4	2.8%	7.7%
General Service		
Schedule 23/723 (0-30kW)	2.8%	7.7%
Schedule 28/728 (31-200kW)	2.8%	5.7%
Schedule 30/730 (201-999kW)	2.8%	2.4%
Schedule 48/748 47/747 (≥1,000kW)	2.8%	2.4%
Agricultural Pumping Svc Schedule 41/741	2.8%	7.7%
Lighting Schedules	2.8%	0.0%
Overall	2.8%	5.7%

Under the company's proposal, the incremental general rate case rate change that takes effect at the end of this proceeding will result in no customer rate schedule class receiving an increase greater than 7.7 percent, or 1.35 times the overall increase of 5.7 percent, and no class will see a rate decrease. The company's proposed rate spread strikes a balance between moderating rate impacts on customers and sending proper price signals about increasing costs. The company proposes revisions to the RMA to achieve these goals.

Q. Please describe the RMA.

A. The RMA, Schedule 299, is designed to mitigate the impacts of changes in the functionalized revenue requirement on net rates across rate schedules. Net rates are the rates that customers pay once all tariff riders (including the RMA) are taken into account. The RMA is designed to be revenue neutral overall at the time a general rate case price change is implemented, resulting in RMA credits for some rate schedule classes requiring rate mitigation with offsetting RMA charges for others. The RMA was first implemented in docket UE 116 to transition to cost of service rates under

Senate Bill 1149. The Schedule 299 RMA tariff rider is included in customers' rates for delivery services in order to minimize the effect of the price change allocation across customer classes.

Q. Besides mitigation of rate changes across rate schedules, what other factors contribute to the adjustment of the RMA in a general rate case?

A. In each general rate case, the RMA must be rebalanced in order to achieve revenue neutrality so that the revenues from the RMA charges and the RMA credits are in balance. The present Schedule 299 RMA rates were designed to be revenue neutral in the calendar year 2025 forecast test period from the company's 2025 rate case, docket UE 433. Generally, due to changes in rate schedule loads, present Schedule 299 RMA rates would not produce revenue neutrality in the updated test year.[2] However, in this case, the existing RMA is nearly revenue neutral in the updated calendar year 2027 test period. The present RMA rates result in RMA charges that exceed RMA credits by just $2,000 for the 2027 test period loads (see Exhibit PAC/1005, Table 1005-3, Column 15, Row 18). The proposed RMA rates have been designed to be revenue neutral for the 2027 test period (see Exhibit PAC/1005, Table 1005-3, Column 16, Row 18). Since both present and proposed RMA rates are nearly revenue neutral, there is no discernable RMA rebalancing adjustment required in this case.

Q. What are the present and proposed RMA revenues and rates in this case?

A. The present and proposed RMA revenues are shown in Exhibit PAC/1005, Table 1005-3, columns (15) and (16). Present and proposed RMA rates are shown in Exhibit PAC/1005, Table 1005-4, columns (17) through (22).

[2] For example, in the 2023 Rate Case, the RMA required a rebalancing adjustment of $4.5 million. In the 2025 Rate Case, the RMA required a rebalancing adjustment of $0.4 million.

Q. What is the company's RMA objective in this case?

A. The company's RMA objective in this case is to minimize net impacts on customers while sending reasonable price signals about increasing costs. The company proposes increases to the RMA credits to cap the net rate increase for residential, small general service, and irrigation customers at 1.35 times the overall incremental general rate case increase. For larger general service and lighting schedules, changes in RMA surcharges, distinguished by voltage level, were required to ensure no customer class sees a decrease out of this case with overall increasing costs, and to balance the RMA.

Overall, these proposals result in just and reasonable rates and will mitigate rate impacts while sending reasonable price signals.

VI. RATE DESIGN

Q. Please generally describe the process for designing rates to collect the proposed revenue requirement.

A. Proposed rates are designed to collect the target functionalized revenue requirement based on customer billing determinants including number of monthly bills, kilowatts, and kilowatt-hours consumed for the rate case test period. The billing determinants used in this case reflect the forecast test period for the 12 months ending December 2027.

Q. How are the forecast billing determinants developed?

A. Forecast test period billing determinants are developed based on the company's forecast test period bills and energy forecasts along with the historical test period billing determinants.

A three-step process occurs in developing test period billing determinants. First, the company forecasts monthly test period bills and energy by class and by rate schedule, which is supported in the testimony of company witness Travis R. Walker.

Second, a full set of billing determinants, including all rate elements such as kilowatt demand, load size, reactive power quantities, and kilowatt-hour by rate block, are retrieved at the customer invoice level from the company's billing system for the base period—in this case, the 12 months ended June 2025. These historical billing determinants are summarized by class, rate schedule, and voltage level.

Finally, a full set of forecast billing determinants is developed using the historical base period data and the test period forecast. The forecast billing determinants are calculated based upon the ratio of historical bills and energy (temperature normalized) in the base period to the forecast bills and energy provided in the sales forecast.

Q. Have you provided an exhibit showing proposed rates and the billing determinants used to design rates?

A. Yes. Pages 3 through 11 of Exhibit PAC/1004 contain historical and forecast billing determinants along with present and proposed base rates.

Q. Please highlight and summarize the rate design changes proposed by the company.

A. In this case the company is proposing to increase the residential single-family basic charge from $14 to $17 and the multi-family basic charge from $8 to $9.

For other rate schedules, the company generally proposes applying the functionalized rate change on an equal percentage basis to the different functionalized prices.

Residential Rate Design

Q. Please explain the proposed tariffs and rates for residential customers.

A. The standard rate schedule for residential customers is Delivery Service Schedule 4. To recover distribution related costs, the company proposes increasing the basic charge from its current level of $14 per month to $17 for single-family customers and from $8 to $9 for multi-family customers. Volumetric distribution rates are updated to collect the remaining distribution related costs.

For residential customers, as well as for all classes of customers, Transmission and Ancillary Service charges and System Usage charges are updated to recover the costs for those functions as indicated in pages 1 and 2 of Exhibit PAC/1004. Non-NPC generation revenue requirement is recovered through updates to the relevant Schedule -200 Base Supply Service rates.

Q. Why is the company proposing an increase in its basic charge for residential customers?

A. The company's marginal cost-of-service study, which company witness Kenneth Lee Elder, Jr. presents as Exhibit PAC/907, shows on Table 2 that the annual marginal cost of billing- and commitment-related cost is about $39.22 per month. These are costs that do not vary with monthly customer usage and could reasonably be recovered through a fixed monthly charge. Exhibit PAC/908 shows the components of this cost for the total residential class as well as broken-out for single-family and multi-family

residential customers. At the present prices of $14 for single-family and $8 for multi-family, the company's basic charge falls far short of cost. Increasing basic charges by some amount better reflects the fixed costs of serving residential customers and more fairly apportions cost between fixed and volumetric charges. Increasing the amount of revenue collected through basic charges lowers the energy charge. Making movement towards a cost-based basic charge will help the company keep energy usage more affordable for its customers.

Q. How do the company's current and proposed basic charges compare to other utilities in Oregon?

A. PacifiCorp's current and proposed basic charges compare very favorably to the basic charges of other Oregon electric utilities. The company examined the residential rates of 15 other utilities including the other two electric investor-owned utilities in the state and 13 publicly owned electric utilities with service territory in close proximity to the company's. Table 3 below shows those basic charges as well as an average for all 15 utilities.

Table 3
Comparison of PacifiCorp's Current and Proposed Basic Charge to Other Oregon Electric Utilities

Utility	Single Family Basic Charge	Multi-Family Basic Charge
Current Pacific Power	$14.00	$8.00
Proposed Pacific Power	$17.00	$9.00
Portland General Electric	$13.00	$10.00
Idaho Power	$10.00	Same
Central Electric Coop	$32.56	Same
Central Lincoln PUD	$30.00	Same
City of Ashland	$16.25	Same
City of Hermiston	$24.25	Same
City of Monmouth	$13.73	Same
Coos-Curry Electric Coop	$35.79	Same
Eugene Water and Electric Board	$38.50	Same
Hood River Electric Coop	$27.00	Same
Lane Electric Coop	$49.00	Same
Salem Electric	$31.63	Same
Springfield Utility Board	$21.60	Same
Tillamook PUD	$45.00	Same
Umatilla Electric Coop	$28.60	Same
Average	$27.79	

Note - Prices were those available from each utility's website as of April 24, 2026

The average single family basic charge of all 15 utilities examined is $27.79 which is well above the company's proposed basic charge of $17 for single-family. Besides PacifiCorp, only Portland General Electric Company has a different basic charge for multi-family customers which is presently set at $10. This level is above both the company's current and proposed price for multi-family customers.

Non-Residential Rate Design

Q. What does the company propose for the rate design for non-residential customers?

A. The company is not proposing any changes to the underlying rate structures for non-residential customers. Prices were modified to collect the target revenue requirement and to track functionalized costs. Present and proposed rates for all schedules are detailed in Pages 3 through 11 of Exhibit PAC/1004.

Adjustment Schedules

Q. In addition to the proposed interim rate adjustment described above, please describe the company's proposed changes to existing adjustment schedules in this proceeding.

A. As described in the direct testimony of company witness Shelley E. McCoy, the company proposes changes in this proceeding outside of base rates. Based on the amounts presented in witness McCoy's testimony, PacifiCorp proposes an update to Schedule 190 – Wildfire Mitigation Plan Cost Recovery Adjustment, a new part to Schedule 192 – Deferred Accounting to recover deferred insurance premium costs, and an update to Schedule 203 – Renewable Resource Deferral Adjustment.

Q. Please describe the proposed changes to Schedule 190 – Wildfire Mitigation Plan Cost Recovery Adjustment.

A. PacifiCorp proposes to recover an additional $1.4 million in costs related to wildfire mitigation through Schedule 190 – Wildfire Mitigation Plan Cost Recovery Adjustment. The company proposes to continue use of a distribution rate spread to calculate cents per kilowatt-hour adder rates for Schedule 190, which will collect this

additional amount. The adder rates will be added to the existing Schedule 190 rates. The proposed adder rate calculations and proposed total Schedule 190 rates are shown in Exhibit PAC/1006, page 1.

Q. Please describe the proposed update to Schedule 192 – Deferred Accounting Adjustment.

A. PacifiCorp proposed to recover $1.6 million in deferred costs related to increased insurance premiums through a new part B to Schedule 192 – Deferred Accounting Adjustment. The company proposes an equal percentage of base revenues rate spread, collected on a cents per kilowatt-hour basis. The proposed Schedule 192 part B adjustment rate calculations and rates are shown in Exhibit PAC/1006, page 2.

Q. Please describe the proposed changes to Schedule 203 – Renewable Resource Deferral Adjustment.

A. The company proposes to recover $4.2 million in deferred costs related to Rock Creek I and Rock Creek II from all customers through the Schedule 203 – Renewable Resource Deferral Adjustment. Additionally, the company proposes to collect an annual amount of $1.8 million in deferred amounts related to the delay of the effective date for residential customers of the Renewable Adjustment Clause rate change from January 1, 2026, to April 1, 2026. Both parts are calculated as cents per kilowatt-hour adder rates to be added to the existing Schedule 203 rates. The company proposes to continue the use of a generation rate spread for collection of the Rock Creek I and II costs and proposes to recover the amount for the delayed effective date from only residential customers. The proposed adder rate calculations and total proposed Schedule 203 rates are shown in Exhibit PAC/1006 page 3.

Service Area Transfer Adjustment Schedules

Q. What adjustment rates does the company propose related to the pending Service Area Transfer?

A. The company proposes two adjustment schedule changes to reflect revenue requirement changes at the completion of the Washinton Service Area Transfer: a new credit distributed through the existing Schedule 96 – Property Sales Balancing Account Adjustment and a new adjustment Schedule 81 – Service Area Transfer Adjustment.

Q. Please describe the proposed changes to Schedule 96 – Property Sales Adjustment.

A. As described in the direct testimony of witness McCoy, the company proposes to distribute a credit of $14.3 million per year for three years passing back a portion of the benefits of the Service Area Transfer to Oregon customers through Schedule 96-Property Sales Balancing Account Adjustment. Schedule 96 is distributed on an equal cents per kilowatt-hour basis. Currently, Schedule 96 rates are at zero. The proposed rate calculation and rate is shown in Exhibit PAC/1007 on page 1.

Q. Please describe the proposed new adjustment Schedule 81 – Service Area Transfer Adjustment.

A. The company proposes a new base adjustment Schedule 81 – Service Area Transfer Adjustment to put into rates the additional revenue requirement related to the Service Area Transfer, as described by witness McCoy. The increased amounts are mainly related to company transmission and distribution costs, so the proposed rate spread for this new adjustment is a distribution rate spread recovered on a cents per kilowatt-

hour basis. The proposed rate calculation and rates are shown in Exhibit PAC/1007 on page 2.

Q. What effective date does the company propose for the adjustment rates related to the Service Area Transfer, Schedules 96 and 81?

A. The company proposes that the changes to adjustment Schedules 96 and 81 take effect upon the closing date of the Service Area Transfer or on the final effective date of this general rate case proceeding, whichever comes later.

Q. What is the net rate impact of these two proposed adjustments?

A. The overall net rate impact of the two proposed adjustments related to the Serviced Area Transfer is a small increase of $3.0 million or 0.1 percent. The table in Exhibit PAC/1007 page 3 shows the net impact of the two adjustments by rate schedule. Present revenues in this table reflect the proposed revenues coming out of the final general rate case change in this proceeding.

Schedule 300 Facilities Charges

Q. What are the Schedule 300 Facilities Charges and how do they apply to customers?

A. The Facilities Charges in the company's Schedule 300 recover the annualized cost of ownership from the customer whose line extension request causes the company to incur those costs. They apply, in accordance with Rule 13, to customers requesting a line extension to a new site or increased capacity at an existing site. The customer only pays that portion of the facilities charge not covered by the Contract Minimum Billing as given in Rule 13.

Q. How are the Schedule 300 Facilities Charges set?

A. The Schedule 300 Facilities Charges are set based on financial models which reflect factors such as return on capital and local property taxes. The charges are updated periodically in a general rate case. The last update was done in the company's docket UE 374 general rate case based on factors from 2018.

Q. What changes does the company propose for Schedule 300 Facilities Charges?

A. PacifiCorp is proposing to update the Schedule 300 Facilities Charges for new distribution and transmission service based on the most currently available factors from 2024. Table 4 below shows both the current Schedule 300 Facilities Charges and proposed Schedule 300 Facilities Charges by voltage.

Table 4

Schedule 300 Facilities Charges		
	Current	**Proposed**
Distribution-Voltage Equipment (<57,000 volts)		
On Consumer expense (advance)	0.40%	**0.74%**
On Company expense (allowance)	1.20%	**1.57%**
Transmission-Voltage Equipment (≥57,000 volts)		
On Consumer expense (advance)	0.20%	**0.19%**
On Company expense (allowance)	0.85%	**0.93%**

The calculation of the proposed Schedule 300 Facilities Charges are provided in Exhibit PAC/1008.

VII. CUMULATIVE ECONOMIC IMPACT ANALYSIS

Q. What are the requirements of OAR 860-022-0500 adopted by the Commission in November 2025 by Order No. 25-468?

A. OAR 860-022-0500 requires that, in determining whether a proposed residential rate to be established, increased, or modified is fair, just, and reasonable, the Commission must balance the interest of the utility and consumers by considering the cumulative economic impact of the proposed rates.

Q. What is the company's responsibility under OAR 860-022-0500?

A. The company is required, for any filing which will result in an increase to residential rates and where the company's return on equity is subject to review, to conduct an analysis of the cumulative economic impact of proposed rates on residential ratepayers.[3] OAR 860-022-0500 lays out the specific requirements of this economic impact analysis.

Q. Does this proceeding require the indicated economic impact analysis?

A. Yes. The company proposes an overall net 10.8 percent net increase for residential customers from this entire general rate case and the company's return on equity is subject to review.

Q. What are the key components of the required economic impact analysis?

A. The company must provide these key elements in its economic impact analysis:

- Distinguishing by single family and multi-family residential customers, the average monthly residential bill for the 18 months ending on the day before the proposed effective date of the rate change, the residential winter bill range for

[3] OAR 860-022-0500(3).

space heating customers over the prior two winters, and the annual estimated dollar and percentage increase in residential utility bills under the proposed rates.

- The average cost of living and fuel/utilities for the region using the Bureau of Labor Statistics most recent Consumer Price Index for All Urban Consumers, West Region (All items).
- The utility's residential disconnection data for the past twelve months, including total disconnections, disconnections among customers receiving energy assistance, the number of customers with medical certificates, and data on customers enrolled in energy assistance or disconnection moratorium programs.
- Data on overdue residential balances, including the number of customers with overdue bills, the average overdue amount, and the total overdue balances owed.
- The relative cost of energy for commercial and industrial customers compared with those in other regional states, including historical cost trends.
- Any other relevant data, as determined by the Commission.

Q. Has the company prepared the cumulative economic impact analysis that meets these requirements?

A. Yes. Exhibit PAC/1009 provides the cumulative economic impact analysis as required by OAR 860-022-0500. Note that the annual estimated dollar and percentage increase in residential utility bills under the proposed rates are provided in the rate impact tables and monthly billing comparisons accompanying my testimony in Exhibit PAC/1005.

VIII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 470
Exhibit PAC/1001
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Summary of Proposed Rate Changes in this General Rate Case and Summary of Proposed Rate Changes Including TAM and PCAM Rate Cancellations

May 2026

Rate Change Summary

PACIFIC POWER
SUMMARY OF ESTIMATED EFFECT OF PROPOSED PRICE CHANGES
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2027

Line No.	Description	Sch No.	No. of Cust	MWh	Present Net Revs ($000)	Interim Net Revs ($000)	Interim Change ($000)	Interim Change %[2]	Incremental GRC Net Revs ($000)	Incremental GRC Change ($000)	Incremental GRC Change %[2]	WA Service Area Transfer Net Revs ($000)	WA Service Area Transfer Change ($000)	WA Service Area Transfer Change %[2]	All Parts Change ($000)	All Parts Change %[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (6) - (5)	(8) (7)/(5)	(9)	(10) (9) - (6)	(11) (10)/(6)	(12)	(13) (12) - (9)	(14) (13)/(9)	(15) (12) - (5)	(16) (15)/(5)	
	Residential																
1	Schedule 4 - Single Family	4	436,916	4,774,187	$747,937	$768,879	$20,942	2.8%	$829,359	$60,480	7.9%	$833,703	$4,345	0.5%	$85,766	11.5%	1
2	Schedule 4 - Multi-Family	4	120,768	805,836	$125,432	$128,944	$3,512	2.8%	$137,969	$9,025	7.0%	$138,702	$733	0.5%	$13,271	10.6%	2
3	**Total Residential**		557,684	5,580,023	$873,369	$897,823	$24,454	2.8%	$967,328	$69,505	7.7%	$972,406	$5,078	0.5%	$99,037	11.3%	3
	Commercial & Industrial																
4	Gen. Svc. < 31 kW	23	88,061	1,107,088	$176,217	$181,151	$4,934	2.8%	$195,183	$14,032	7.7%	$196,534	$1,351	0.7%	$20,317	11.5%	4
5	Gen. Svc. 31 - 200 kW	28/29	10,623	1,973,007	$226,670	$233,017	$6,347	2.8%	$246,258	$13,241	5.7%	$246,238	($20)	0.0%	$19,568	8.6%	5
6	Gen. Svc. 201 - 999 kW	30	839	1,270,076	$136,011	$139,819	$3,808	2.8%	$143,163	$3,344	2.4%	$142,795	($368)	-0.3%	$6,784	5.0%	6
7	Large General Service >= 1,000 kW	48	200	5,843,551	$508,955	$523,205	$14,251	2.8%	$536,112	$12,907	2.4%	$532,898	($3,214)	-0.6%	$23,943	4.7%	7
8	Partial Req. Svc. >= 1,000 kW	47	6	35,271	$4,963	$5,102	$139	2.8%	$5,117	$15	2.4%	$5,098	($19)	-0.6%	$135	4.7%	8
9	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$2,228	$2,291	$62	2.8%	$2,292	$1	0.0%	$2,200	($91)	-4.0%	($28)	-1.2%	9
10	Agricultural Pumping Service	41	7,808	225,796	$31,847	$32,739	$892	2.8%	$35,258	$2,519	7.7%	$35,561	$303	0.9%	$3,714	11.7%	10
11	**Total Commercial & Industrial**		107,538	10,454,790	$1,086,891	$1,117,324	$30,433	2.8%	$1,163,383	$46,059	4.1%	$1,161,324	($2,059)	-0.2%	$74,433	6.8%	11
	Lighting																
12	Outdoor Area Lighting Service	15	5,841	7,817	$1,116	$1,147	$31	2.8%	$1,147	($0)	0.0%	$1,160	$14	1.2%	$45	4.0%	12
13	Street Lighting Service Comp. Owned	51	1,306	20,175	$4,182	$4,299	$117	2.8%	$4,299	($0)	0.0%	$4,347	$48	1.1%	$165	3.9%	13
14	Street Lighting Service Cust. Owned	53	302	8,105	$683	$702	$19	2.8%	$702	$0	0.0%	$702	$0	0.0%	$19	2.8%	14
15	Recreational Field Lighting	54	96	1,365	$140	$144	$4	2.8%	$144	$0	0.0%	$145	$0	0.2%	$4	3.0%	15
16	**Total Public Street Lighting**		7,545	37,461	$6,121	$6,292	$171	2.8%	$6,292	($0)	0.0%	$6,355	$62	1.0%	$234	3.8%	16
17	**Subtotal**		672,767	16,072,275	$1,966,381	$2,021,440	$55,059	2.8%	$2,137,004	$115,564	5.7%	$2,140,084	$3,081	0.1%	$173,704	8.8%	17
18	Emplolyee Discount		*978*	*13,169*	($505)	($502)	$4		($559)	($57)		($562)	($3)		($57)		18
19	Paperless Credit				($1,991)	($1,991)	$0		($1,991)	$0		($1,991)	$0		$0		19
20	AGA Revenue				$9,715	$9,715	$0		$9,715	$0		$9,715	$0		$0		20
21	COOC Amortization				$44	$44	$0		$44	$0		$44	$0		$0		21
22	**Total**		672,767	16,072,275	$1,973,643	$2,028,705	$55,062	2.8%	$2,144,212	$115,507	5.7%	$2,147,290	$3,078	0.1%	$173,647	8.8%	22

[1] Excludes effects of the low income assistance charges (Sch. 91 and Sch. 92), BPA credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Trust of Oregon and Energy Efficiency Funding Charge (Sch. 292).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Rate Change Summary - Including Estimated TAM and PCAM Cancelations

PACIFIC POWER
SUMMARY OF ESTIMATED EFFECT OF PROPOSED PRICE CHANGES
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2027

Line No.	Description	Sch No.	No. of Cust	Cancel 2022 PCAM	Interim Adj.	TAM	Cancel 2021, 2023, 2024 PCAM	Incremental GRC	WA Svc. Area Transfer	Sum of Changes	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
	Residential										
1	Schedule 4 - Single Family	4	436,916	-2.8%	2.8%	-2.3%	-4.0%	7.9%	0.5%	2.1%	1
2	Schedule 4 - Multi-Family	4	120,768	-2.8%	2.8%	-2.3%	-4.1%	7.0%	0.5%	1.1%	2
3	**Total Residential**		557,684	-2.8%	2.8%	-2.3%	-4.0%	7.7%	0.5%	1.9%	3
	Commercial & Industrial										
4	Gen. Svc. < 31 kW	23	88,061	-2.6%	2.8%	-2.2%	-3.7%	7.7%	0.7%	2.7%	4
5	Gen. Svc. 31 - 200 kW	28/29	10,623	-3.3%	2.8%	-2.9%	-5.0%	5.7%	0.0%	-2.7%	5
6	Gen. Svc. 201 - 999 kW	30	839	-3.6%	2.8%	-3.1%	-5.3%	2.4%	-0.3%	-7.1%	6
7	Large General Service >= 1,000 kW	48	200	-4.2%	2.8%	-3.7%	-6.1%	2.4%	-0.6%	-9.4%	7
8	Partial Req. Svc. >= 1,000 kW	47	6	-4.2%	2.8%	-3.7%	-6.1%	2.4%	-0.6%	-9.4%	8
9	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0.0%	2.8%	0.0%	0.0%	0.0%	-4.0%	-1.2%	9
10	Agricultural Pumping Service	41	7,808	-2.7%	2.8%	-2.3%	-4.0%	7.7%	0.9%	2.4%	10
11	**Total Commercial & Industrial**		107,538	-3.6%	2.8%	-3.2%	-5.3%	4.1%	-0.2%	-5.4%	11
	Lighting										
12	Outdoor Area Lighting Service	15	5,841	-1.1%	2.8%	-0.7%	-1.5%	0.0%	1.2%	0.7%	12
13	Street Lighting Service Comp. Owned	51	1,306	-0.9%	2.8%	-0.7%	-1.4%	0.0%	1.1%	0.9%	13
14	Street Lighting Service Cust. Owned	53	302	-1.6%	2.8%	-1.1%	-2.3%	0.0%	0.0%	-2.2%	14
15	Recreational Field Lighting	54	96	-1.3%	2.8%	-0.9%	-1.9%	0.0%	0.2%	-1.1%	15
16	**Total Public Street Lighting**		7,545	-1.1%	2.8%	-0.8%	-1.6%	0.0%	1.0%	0.3%	16
17	**Subtotal**		672,767	-3.2%	2.8%	-2.8%	-4.7%	5.7%	0.1%	-2.1%	17
18	Emplolyee Discount		*978*								18
19	Paperless Credit										19
20	AGA Revenue										20
21	COOC Amortization										21
22	**Total**		672,767	-3.2%	2.8%	-2.8%	-4.7%	5.7%	0.1%	-2.1%	22

* Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Docket No. UE 470
Exhibit PAC/1002
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Interim Rate Adjustment, Interim Tariffs and Estimated Effect of Proposed Interim Rate Adjustment

May 2026

PACIFIC POWER
STATE OF OREGON
Calculation of Proposed Interim Rate Adjustment - Schedule 80

FORECAST 12 MONTHS ENDED DECEMBER 31, 2027

Line No.	Description	Sch No.	MWh*	Present Net Revenues ($000)	Proposed Schedule 80 Base Rates (¢/kWh)	Proposed Schedule 80 Base Revenues ($000)
	(1)	(2)	(3)	(4)	(5)	(6)
	Residential					
1	Schedule 4 - Single Family	4	4,774,187	$747,937	2.80%	$20,942
2	Schedule 4 - Multi-Family	4	805,836	$125,432	2.80%	$3,512
3	**Total Residential**		5,580,023	$873,369		$24,454
	Commercial & Industrial					
4	Gen. Svc. < 31 kW	23	1,107,088	$176,217	2.80%	$4,934
5	Gen. Svc. 31 - 200 kW	28/29	1,973,007	$226,670	2.80%	$6,347
6	Gen. Svc. 201 - 999 kW	30	1,270,076	$136,011	2.80%	$3,808
7	Large General Service >= 1,000 kW	48	5,843,551	$508,955	2.80%	$14,251
8	Partial Req. Svc. >= 1,000 kW	47	35,271	$4,963	2.80%	$139
9	Dist. Only Lg Gen Svc >= 1,000 kW	848	165,688	$2,228	2.80%	$62
10	Agricultural Pumping Service	41	225,796	$31,847	2.80%	$892
11	**Total Commercial & Industrial**		10,620,478	$1,086,891		$30,433
	Lighting					
12	Outdoor Area Lighting Service	15	2,189	$1,116	2.80%	$31
13	Street Lighting Service Comp. Owned	51	8,881	$4,182	2.80%	$117
14	Street Lighting Service Cust. Owned	53	8,105	$683	2.80%	$19
15	Recreational Field Lighting	54	1,365	$140	2.80%	$4
16	**Total Lighting**		20,539	$6,121		$171
17	**Subtotal**		16,221,040	$1,966,381		$55,059
18	Emplolyee Discount			($505)		$4
19	**Total Sales with Employee Discount**			$1,965,876		$55,062

* Includes Distribution Only consumer MWh and lighting tariff MWh

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299	Rate Mitigation Adjustment

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 80

INTERIM RATE ADJUSTMENT

 (N)

Purpose

To implement an interim rate adjustment with Order No. 26-XXX.

Applicable

To all Residential and Nonresidential Consumers.

Monthly Billing

All bills calculated in accordance with Schedules contained in the presently effective Tariff will have applied the following percentage to net revenues prior to the application of pass-through adjustment Schedules 91, 92, 98, 290 and 292 and prior to the application of local taxes and fees.

Interim Rate Adjustment	2.8 percent

(N)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 90

SUMMARY OF EFFECTIVE RATE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules

SUMMARY OF EFFECTIVE RATE ADJUSTMENTS

(N)

Schedule	80	91	92	93	94	96	97	98*	190	192	202*	203*	204
4	x	x	x	x	x	x	x	x	x	x	x	x	x
5	x	x	x	x	x	x	x	x	x	x	x	x	x
15	x	x	x	x	x	x		x	x	x	x	x	x
23	x	x	x	x	x	x		x	x	x	x	x	x
28	x	x	x	x	x	x		x	x	x	x	x	x
30	x	x	x	x	x	x		x	x	x	x	x	x
41	x	x	x	x	x	x		x	x	x	x	x	x
47	x	x	x	x	x	x	x	x	x	x	x	x	x
48	x	x	x	x	x	x	x	x	x	x	x	x	x
51	x	x	x	x	x	x			x	x	x	x	x
53	x	x	x	x	x	x			x	x	x	x	x
54	x	x	x	x	x	x			x	x	x	x	x
60													
723	x	x	x	x	x	x		x	x	x	x	x	x
728	x	x	x	x	x	x		x	x	x	x	x	x
730	x	x	x	x	x	x		x	x	x	x	x	x
741	x	x	x	x	x	x		x	x	x	x	x	x
747	x	x	x	x	x	x	x	x	x	x	x	x	x
748	x	x	x	x	x	x	x	x	x	x	x	x	x
751	x	x	x	x	x	x			x	x	x	x	x
753	x	x	x	x	x	x			x	x	x	x	x
754	x	x	x	x	x	x			x	x	x	x	x
848	x	x	x		x		x		x	x			

(N)

*Not applicable to all consumers. See Schedule for details.

(continued)

Interim Rate Adjustment

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, 2027

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	Schedule 4 - Single Family	4	436,916	4,774,187	$686,255	$61,683	$747,937	$707,197	$61,683	$768,879	$20,942	3.1%	$20,942	2.8%	1
2	Schedule 4 - Multi-Family	4	120,768	805,836	$115,020	$10,411	$125,432	$118,532	$10,411	$128,944	$3,512	3.1%	$3,512	2.8%	2
3	**Total Residential**		557,684	5,580,023	$801,275	$72,094	$873,369	$825,729	$72,094	$897,823	$24,454	3.1%	$24,454	2.8%	3
	Commercial & Industrial														
4	Gen. Svc. < 31 kW	23	88,061	1,107,088	$164,694	$11,523	$176,217	$169,628	$11,523	$181,151	$4,934	3.0%	$4,934	2.8%	4
5	Gen. Svc. 31 - 200 kW	28/29	10,623	1,973,007	$195,242	$31,428	$226,670	$201,589	$31,428	$233,017	$6,347	3.3%	$6,347	2.8%	5
6	Gen. Svc. 201 - 999 kW	30	839	1,270,076	$117,051	$18,960	$136,011	$120,859	$18,960	$139,819	$3,808	3.3%	$3,808	2.8%	6
7	Large General Service >= 1,000 kW	48	200	5,843,551	$461,603	$47,352	$508,955	$475,854	$47,352	$523,205	$14,251	3.1%	$14,251	2.8%	7
8	Partial Req. Svc. >= 1,000 kW	47	6	35,271	$4,676	$288	$4,963	$4,814	$288	$5,102	$139	3.1%	$139	2.8%	8
9	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$1,920	$308	$2,228	$1,982	$308	$2,291	$62	3.2%	$62	2.8%	9
10	Agricultural Pumping Service	41	7,808	225,796	$34,896	($3,048)	$31,847	$35,787	($3,048)	$32,739	$892	2.6%	$892	2.8%	10
11	**Total Commercial & Industrial**		107,538	10,454,790	$980,081	$106,810	$1,086,891	$1,010,514	$106,810	$1,117,324	$30,433	3.1%	$30,433	2.8%	11
	Lighting														
12	Outdoor Area Lighting Service	15	5,841	7,817	$893	$223	$1,116	$924	$223	$1,147	$31	3.5%	$31	2.8%	12
13	Street Lighting Service Comp. Owned	51	1,306	20,175	$3,205	$977	$4,182	$3,322	$977	$4,299	$117	3.7%	$117	2.8%	13
14	Street Lighting Service Cust. Owned	53	302	8,105	$455	$228	$683	$474	$228	$702	$19	4.2%	$19	2.8%	14
15	Recreational Field Lighting	54	96	1,365	$92	$48	$140	$96	$48	$144	$4	4.3%	$4	2.8%	15
16	**Total Public Street Lighting**		7,545	37,461	$4,645	$1,476	$6,121	$4,816	$1,476	$6,292	$171	3.7%	$171	2.8%	16
17	**Subtotal**		672,767	16,072,275	$1,786,001	$180,380	$1,966,381	$1,841,059	$180,380	$2,021,440	$55,059	3.1%	$55,059	2.8%	17
18	Emplolyee Discount		*978*	*13,169*	($463)	($43)	($505)	($459)	($43)	($502)	$4		$4		18
19	Paperless Credit				($1,991)		($1,991)	($1,991)		($1,991)	$0		$0		19
20	AGA Revenue				$9,715		$9,715	$9,715		$9,715	$0		$0		20
21	COOC Amortization				$44		$44	$44		$44	$0		$0		21
22	**Total**		672,767	16,072,275	$1,793,305	$180,338	$1,973,643	$1,848,368	$180,338	$2,028,705	$55,062	3.1%	$55,062	2.8%	22

[1] Excludes effects of the low income assistance charges (Sch. 91 and Sch. 92), BPA credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Trust of Oregon and Energy Efficiency Funding Charge (Sch. 292).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Docket No. UE 470
Exhibit PAC/1003
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed General Rate Case Tariffs

May 2026

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
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PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 4

RESIDENTIAL SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To single-family Residential Consumers only for all single-phase and three-phase electric requirements when all service is supplied at one point of delivery. Three-phase service will be supplied only when service is available from Company's presently existing facilities, or where such facilities can be installed under Company's Line Extension Rules, and, in any event, only when deliveries can be made by using one service for Consumer's single-phase and three-phase requirements.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		
Single-Family Home Basic Charge, per month	$17.00	(I)
Multi-Family Home Basic Charge, per month	$9.00	(I)
Three-Phase Charge, per month	$9.00	
Distribution Energy Charge, per kWh	6.582¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	1.206¢	(I)
System Usage Charge		
Schedule 200 Related, per kWh	0.072¢	(I)
T&A and Schedule 201 Related, per kWh	0.131¢	(I)

Supply Service Options

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201, Schedule 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule.

Time-of-Use Option

Consumers taking service under this schedule may also choose to participate in a time-of-use option, which provides time-varying energy rates. Rates and hours for this option are shown in Schedule 201.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 5

SEPARATELY METERED ELECTRIC VEHICLE SERVICE FOR RESIDENTIAL CONSUMERS
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To single-family Residential Consumers only for all single-phase and three-phase electric requirements supplied to electric vehicle charging installations where such service is supplied at a point of delivery separately metered from other residential service. Three-phase service will be supplied only when service is available from Company's presently existing facilities.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		
Single-Family Home Basic Charge, per month	$17.00	(I)
Multi-Family Home Basic Charge, per month	$9.00	(I)
Three-Phase Charge, per month	$9.00	
Distribution Energy Charge, per kWh	6.582¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	1.206¢	(I)
System Usage Charge		
Schedule 200 Related, per kWh	0.072¢	(I)
T&A and Schedule 201 Related, per kWh	0.131¢	(I)

Supply Service Options

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201, Schedule 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule.

Time-of-Use Option

Consumers taking service under this schedule may also choose to participate in a time-of-use option, which provides time-varying energy rates. Rates and hours for this option are shown in Schedule 201.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 15

OUTDOOR AREA LIGHTING SERVICE -
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Consumers for outdoor area lighting service furnished from dusk to dawn by means of Company-owned lamps which may be served by secondary voltage circuits from the Company's existing overhead distribution system. Luminaires shall be mounted on Company-owned wood poles and served in accordance with the Company's specifications as to equipment and installation. Lamp installations on any pole except an existing distribution pole are closed to new service.

Monthly Billing

The Monthly Billing shall be the Rate Per Luminaire plus the applicable adjustments as specified in Schedule 90.

Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate Per Lamp	
Level 1	0-5,000	19	$7.81	(I)
Level 2	5,001-12,000	34	$9.02	(I)
Level 3	12,001+	57	$10.81	(I)

Supply Service Option

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Supply Service shall be provided by Supply Service Schedule 201.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, Transmission & Ancillary Services, Schedule 201, Net Power Costs, and distribution charges are collected through rates in this schedule.

Special Conditions

1. Inoperable lights will be repaired as soon as reasonably possible, during regular business hours or as allowed by Company's operating schedule and requirements, provided the Company receives notification of inoperable lights from Consumer or a member of the public by either notifying Pacific Power's customer service (1-888-221-7070) or www.pacificpower.net/streetlights. Pacific Power's obligation to repair street lights is limited to this tariff.

2. The Company reserves the right to contract for the maintenance of lighting service provided hereunder.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 23

GENERAL SERVICE - SMALL NONRESIDENTIAL
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Small Nonresidential Consumers whose entire electric service requirements are supplied hereunder and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed, except as provided below for Communication Devices. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Single Phase, per month	$27.40	$27.40	(I)
Three Phase, per month	$40.85	$40.85	(I)
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW Load Size	$2.60	$2.60	(I)
Demand Charge, the first 15 kW of demand	No Charge	No Charge	
Demand Charge, for all kW in excess of 15 kW, per kW	$8.53	$8.42	(I)
Distribution Energy Charge, per kWh	6.299¢	6.202¢	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	1.046¢	1.030¢	(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.066¢	0.065¢	(I)
T&A and Schedule 201 Related, per kWh	0.118¢	0.116¢	(R)

kW Load Size

For determination of the Basic Charge and Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 28

GENERAL SERVICE
LARGE NONRESIDENTIAL 31 KW to 200 KW
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

	Delivery Voltage		
	Secondary	**Primary**	
Distribution Charge			
Basic Charge			
Load Size ≤50 kW, per month	$ 31.00	$ 38.00	(I)
Load Size 51-100 kW, per month	$ 59.00	$ 66.00	|
Load Size 101 - 300 kW, per month	$140.00	$150.00	|
Load Size > 300 kW, per month	$198.00	$215.00	(I)
Load Size Charge			
≤50 kW, per kW Load Size	$ 1.95	$ 2.15	(I)
51 - 100 kW, per kW Load Size	$ 1.55	$ 1.70	|
101 – 300 kW, per kW Load Size	$ 1.00	$ 1.05	|
> 300 kW, per kW Load Size	$ 0.60	$ 0.50	|
Demand Charge, per kW	$ 6.71	$ 7.39	|
Distribution Energy Charge, per kWh	0.693¢	0.115¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
Transmission & Ancillary Services Charge			
Per kW	$ 2.91	$ 2.82	(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.067¢	0.070¢	(I)
T&A and Schedule 201 Related, per kWh	0.119¢	0.123¢	(R, I)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the demand charge. A higher minimum may be required under contract to cover special conditions.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 29

GENERAL SERVICE TIME-OF-USE
LARGE NONRESIDENTIAL
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have not registered more than 1,000 kW, more than three times in the preceding 12-month period or more than 2,000 kW more than once in the preceding 18-month period and who are not otherwise subject to service on Schedules 47 or 48. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge and System Usage Charge plus the applicable adjustments as specified in Schedule 90 for Schedule 28.

Distribution Charge		
Basic Charge, per month	$62.85	(I)
Distribution Energy Charge		
First 50 kWh per kW demand, per kWh	31.049¢	(I)
All Additional kWh, per kWh	-1.699¢	
Transmission & Ancillary Services Charge		
Per kWh	0.974¢	(I)
System Usage Charge		
Schedule 200 Related, per kWh	0.067¢	(I)
T&A and Schedule 201 Related, per kWh	0.119¢	(R)

Minimum Charge

The minimum monthly charge shall be the Basic Charge. A higher minimum may be required under contract to cover special conditions.

Demand

The kW shown by or computed from the readings of the Company's demand meter for the 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW, but not less than 15 kW.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall pay the applicable rates in Supply Service Schedule 201. Time-of-use rates and hours for Supply Service under this schedule are shown in Schedule 201.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 30

GENERAL SERVICE
LARGE NONRESIDENTIAL 201 KW to 999 KW
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedules 47 or 48. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤200 kW, per month	$773.00	$625.00	(I, R)
Load Size 201 - 300 kW, per month	$223.00	$195.00	(I, R)
Load Size > 300 kW, per month	$593.00	$510.00	(I, R)
Load Size Charge			
≤200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$2.75	$2.15	(I)
> 300 kW, per kW Load Size	$1.35	$1.05	(I)
Demand Charge, per kW	$6.50	$5.40	(I, R)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kW	$3.43	$3.02	(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.071¢	0.072¢	(I)
T&A and Schedule 201 Related, per kWh	0.125¢	0.125¢	(I)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 41

AGRICULTURAL PUMPING SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Consumers desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 47 or 48. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

Monthly Billing

Except for November, the monthly billing shall be the sum of the Distribution Energy Charge, Reactive Power Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. For November, the billing shall be the sum of the Basic Charge, Load Size Charge, Distribution Energy Charge, Reactive Power Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge (November billing only)			
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$660.00	$650.00	(I)
Three Phase Load Size > 300 kW	$2,580.00	$2,550.00	(I)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$27.20	$26.80	(I)
Three Phase 51 - 300 kW, per kW Load Size	$18.60	$18.40	(I)
Three Phase > 300 kW, per kW Load Size	$11.50	$11.30	(I)
Single Phase, Minimum Charge	$115.00	$115.00	(I)
Three Phase, Minimum Charge	$195.00	$190.00	(I)
Distribution Energy Charge, per kWh	7.906¢	7.784¢	(I)
Reactive Power Charge, per kVar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.948¢	0.933¢	(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.065¢	0.064¢	(I)
T&A and Schedule 201 Related, per kWh	0.114¢	0.112¢	(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of the Company's meter, or by appropriate test, for the 15-minute period of the Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 47

LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS 1,000 KW AND OVER
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 747, Direct Access Delivery Service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Reserves Charge, Transmission & Ancillary Services Charge, and System Usage Charge plus the applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
Distribution Charge	**Secondary**	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$950.00	$1,130.00	$1,790.00	(I)
Facility Capacity > 4,000 kW, per month	$2,620.00	$3,120.00	$4,590.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$4.05	$1.35	$1.40	(I)
> 4,000 kW, per kW Facility Capacity	$1.60	$0.55	$1.20	(I)
On-Peak Demand Charge, per kW	$6.34	$6.11	$6.22	(I, R, I)
Reactive Power Charges				
Per kvar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.43	N/A	
Reserves Charges				
Spinning Reserves				
Per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company approved Self-Supply Agreement)				
Per kW of Spinning Reserves Level	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
Per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves (with Company-approved Load Reduction Plan or Self-Supply Agreement)				
Per kW of Supplemental Reserves Level	($0.27)	($0.27)	($0.27)	
Transmission & Ancillary Services Charge				
Per kW of On-Peak Demand	$3.26	$3.18	$4.84	(I)
System Usage Charge				
Schedule 200 Related, per kWh	0.068¢	0.074¢	0.066¢	(I)
T&A and Schedule 201 Related, per kWh	0.119¢	0.128¢	0.112¢	(I)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 48

LARGE GENERAL SERVICE 1,000 KW AND OVER
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until the Consumer fails to meet or exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 47.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**			
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$950.00	$1,130.00	$1,790.00	(I)
Facility Capacity > 4,000 kW, per month	$2,620.00	$3,120.00	$4,590.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$4.05	$1.35	$1.40	(I)
> 4,000 kW, per kW Facility Capacity	$1.60	$0.55	$1.20	(I)
On-Peak Demand Charge, per kW	$6.34	$6.11	$6.22	(I, R, I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	(I)
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.43	N/A	
Transmission & Ancillary Services Charge				
Per kW of On-Peak Demand	$3.80	$3.72	$5.38	(I)
System Usage Charge				
Schedule 200 Related, per kWh	0.068¢	0.074¢	0.066¢	(I)
T&A and Schedule 201 Related, per kWh	0.119¢	0.128¢	0.112¢	(I)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 51

STREET LIGHTING SERVICE COMPANY-OWNED SYSTEM DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

The Monthly Billing shall be the rate per luminaire as specified in the rate tables below plus the applicable adjustments as specified in Schedule 90.

Type of Lamp	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6	
LED Equivalent Lumens	0-3,500	3,501-5,500	5,501-8,000	8,001-12,000	12,001-15,500	15,501+	
Monthly kWh	8	15	25	34	44	57	
Functional Lighting	$ 6.42	$ 6.84	$ 7.03	$ 7.20	$ 7.67	$ 9.38	(I)
Functional Lighting - Customer Funded Conversion	$ 3.47	$ 3.69	$ 3.87	$ 4.00	$ 4.30	$ 5.30	(I)
Decorative Series	N/A	$ 11.74	$ 11.91	N/A	N/A	N/A	(I)

Functional Lighting: Common less expensive luminaires that may be mounted either on wood, fiberglass or non-decorative metal poles. The Company will maintain a list of functional light fixtures that are available.

Customer-Funded Conversion: Street lights that have been converted to LED from another lighting type and whose conversion was funded by the Customer.

Decorative Series Lighting: More stylish luminaires mounted vertically on decorative metal poles. The Company will maintain a listing of standard decorative street light fixtures that are available under this Schedule.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 751, Direct Access Delivery Service.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, Transmission & Ancillary Services, Schedule 201, Net Power Costs, and distribution charges are collected through rates in this schedule.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 53

STREET LIGHTING SERVICE CONSUMER-OWNED SYSTEM DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Consumer owned street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

Energy Only Service - Rate per Luminaire

Energy Only Service includes energy supplied from Company's overhead or underground circuits and does not include any maintenance to Consumer's facilities. Maintenance service will be provided only as indicated in the Maintenance Service section below.

The Monthly Billing shall be the rate per luminaire specified in the rate tables below plus the applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor						
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000
Watts	70	100	150	200	250	400
Monthly kWh	31	44	64	85	115	176
Energy Only Service	$ 1.34	$ 1.90	$ 2.76	$ 3.66	$ 4.96	$ 7.58

(I)

Metal Halide					
Lumen Rating	9,000	12,000	19,500	32,000	107,800
Watts	100	175	250	400	1,000
Monthly kWh	39	68	94	149	354
Energy Only Service	$ 1.68	$ 2.93	$ 4.05	$ 6.42	$ 15.25

(I)

For non-listed luminaires the cost will be calculated for 4167 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh
Energy Only Service	4.309

(I)

Maintenance Service (No New Service)

Where the utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for operation and maintenance will be added to the Energy Only Service rates listed above. Monthly Maintenance is only applicable for existing monthly maintenance service agreements in effect prior to May 24, 2006.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 54

RECREATIONAL FIELD LIGHTING - RESTRICTED DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At the Consumer's option, service for recreational field lighting may be taken under the Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge

Basic Charge, Single Phase, per month	$ 6.00	
Basic Charge, Three Phase, per month	$ 9.00	
Distribution Energy Charge, per kWh	4.642¢	(I)

Transmission & Ancillary Services Charge

per kWh	0.099¢	(I)

System Usage Charge

Schedule 200 Related, per kWh	0.013¢	(I)
T&A and Schedule 201 Related, per kWh	0.021¢	(I)

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 754, Direct Access Delivery Service.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

Special Conditions

The Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 76R

LARGE GENERAL SERVICE - PARTIAL REQUIREMENTS SERVICE
ECONOMIC REPLACEMENT POWER RIDER
DELIVERY SERVICE

Purpose

To provide Consumers served on Schedule 47 with the opportunity of purchasing Energy from the Company to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement power except as explicitly agreed to between Company and Consumer.

Applicable

To Large Nonresidential Consumers receiving Delivery Service under Schedule 47.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 47 plus the applicable adjustments as specified in Schedule 90:

	Delivery Voltage			
	Secondary	**Primary**	**Transmission**	
Transmission & Ancillary Services Charge				
Per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.127	$0.124	$0.189	(I)
Daily ERP Demand Charge				
Per kW of Daily ERP On-Peak Demand	$0.247	$0.238	$0.242	(I)

Supply Service

A Consumer taking Delivery Service under this Schedule shall be served under the terms of Supply Service Schedule 276R.

ERP and ENF

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Power Agreement (ERPA). ERP, ENF and ERPA are more fully described in Schedule 276R.

Daily ERP On-Peak Demand

Daily ERP On-Peak Demand shall not be less than the maximum ERP On-Peak Demand scheduled per day and shall not be greater than the difference between the Facility Capacity and the Baseline Demand. Daily ERP On-Peak Demand will be billed for each day in the month that the Company supplies ERP to the Consumer.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 81

SERVICE AREA TRANSFER ADJUSTMENT

(N)

Purpose

The purpose of this schedule is to implement cost recovery of incremental annual revenue requirement related to the Company's transfer of its Washington service area in accordance with Commission Order 27-XXX.

Applicable

To all Residential and Nonresidential Consumers.

Monthly Billing

All bills calculated in accordance with Schedules contained in the presently effective Tariff will have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

Schedule 4	0.179 ¢ per kWh
Schedule 5	0.179 ¢ per kWh
Schedule 15	0.711 ¢ per kWh
Schedule 23, 723	0.210 ¢ per kWh
Schedule 28, 728	0.087 ¢ per kWh
Schedule 30, 730	0.059 ¢ per kWh
Schedule 41. 741	0.222 ¢ per kWh
Schedule 47, 747	0.033 ¢ per kWh
Schedule 48, 748, 848	0.033 ¢ per kWh
Schedule 51, 751	0.631 ¢ per kWh
Schedule 53, 752	0.089 ¢ per kWh
Schedule 54, 754	0.111 ¢ per kWh

(N)

Issued May 5, 2026 **Effective for service on and after June 4, 2026**
Rick Link, Senior Vice President, Regulation and Planning *Advice No. 26-011/Docket No. UE 470*

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 90

SUMMARY OF EFFECTIVE RATE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules

SUMMARY OF EFFECTIVE RATE ADJUSTMENTS

Schedule	81	91	92	93	94	96	97	98*	190	192	202*	203*	204
4	x	x	x	x	x	x	x	x	x	x	x	x	x
5	x	x	x	x	x	x	x	x	x	x	x	x	x
15	x	x	x	x	x	x		x	x	x	x	x	x
23	x	x	x	x	x	x		x	x	x	x	x	x
28	x	x	x	x	x	x		x	x	x	x	x	x
30	x	x	x	x	x	x		x	x	x	x	x	x
41	x	x	x	x	x	x		x	x	x	x	x	x
47	x	x	x	x	x	x	x	x	x	x	x	x	x
48	x	x	x	x	x	x	x	x	x	x	x	x	x
51	x	x	x	x	x	x			x	x	x	x	x
53	x	x	x	x	x	x			x	x	x	x	x
54	x	x	x	x	x	x			x	x	x	x	x
60													
723	x	x	x	x	x	x		x	x	x	x	x	x
728	x	x	x	x	x	x		x	x	x	x	x	x
730	x	x	x	x	x	x		x	x	x	x	x	x
741	x	x	x	x	x	x		x	x	x	x	x	x
747	x	x	x	x	x	x	x	x	x	x	x	x	x
748	x	x	x	x	x	x	x	x	x	x	x	x	x
751	x	x	x	x	x	x			x	x	x	x	x
753	x	x	x	x	x	x			x	x	x	x	x
754	x	x	x	x	x	x			x	x	x	x	x
848	x	x	x		x		x		x	x			

(N)

(N)

*Not applicable to all consumers. See Schedule for details.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 96

PROPERTY SALES BALANCING ACCOUNT ADJUSTMENT

All bills calculated in accordance with schedules contained in presently effective Tariff OR No. 36 shall have applied an amount equal to the product of all kilowatt-hours of use multiplied by the following cents per kilowatt-hour:

-0.088¢ per kWh, (I)

This schedule will be set to zero at such time as the property sales balances have been fully distributed or collected.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 190

WILDFIRE MITIGATION PLAN COST RECOVERY ADJUSTMENT

Purpose

The purpose of this schedule is to implement cost recovery related to the Company's wildfire mitigation plan automatic adjustment clause consistent with OAR 860-300-0080 and ORS 757.210 and Order No. 23-173.

Applicable

To all Residential and Nonresidential Consumers.

Monthly Billing

All bills calculated in accordance with Schedules contained in the presently effective Tariff will have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

(I)

Schedule 4	0.198 ¢ per kWh
Schedule 5	0.198 ¢ per kWh
Schedule 15	0.964 ¢ per kWh
Schedule 23, 723	0.219 ¢ per kWh
Schedule 28, 728	0.100 ¢ per kWh
Schedule 30, 730	0.072 ¢ per kWh
Schedule 41. 741	0.264 ¢ per kWh
Schedule 47, 747	0.045 ¢ per kWh
Schedule 48, 748, 848	0.045 ¢ per kWh
Schedule 51, 751	0.907 ¢ per kWh
Schedule 53, 752	0.118 ¢ per kWh
Schedule 54, 754	0.147 ¢ per kWh

(I)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 192

DEFERRED ACCOUNTING ADJUSTMENT

Purpose

This schedule recovers deferred amounts as authorized by the Commission in Order 22-491, Order 24-447 and Order 27-XXX. (C)

Applicable

To all Residential consumers and Nonresidential consumers.

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule.

Schedule	Part A	Part B	Part C	Part D	**Total Rate**	
4	0.113	0.013	0.066	0.092	0.284 cents per kWh	(I)
5	0.113	0.013	0.066	0.092	0.284 cents per kWh	
15	0.177	0.019	0.007	0.462	0.665 cents per kWh	
23, 723	0.117	0.014	0.051	0.102	0.284 cents per kWh	
28, 728	0.083	0.009	0.014	0.047	0.153 cents per kWh	
30, 730	0.074	0.008	0.009	0.034	0.125 cents per kWh	
41, 741	0.124	0.014	0.023	0.125	0.286 cents per kWh	
47, 747	0.063	0.006	0.008	0.022	0.099 cents per kWh	
48, 748, 848	0.063	0.006	0.008	0.022	0.099 cents per kWh	
51, 751	0.177	0.019	0.007	0.436	0.639 cents per kWh	
53, 753	0.177	0.019	0.007	0.057	0.260 cents per kWh	
54, 754	0.177	0.019	0.007	0.071	0.274 cents per kWh	(I)

Part A rates recover amounts related to deferred insurance costs approved for amortization in Order 24-447 over approximately three years.

Part B rates recover amounts related to deferred insurance premium costs approved for amortization in Order 27-XXX over approximately one year. (C) (C)

Part C rates recover amounts approved for amortization over four years.

Part D rates recover amounts related to wildfire restoration costs approved for amortization in Order 24-447 over approximately three years.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 200

BASE SUPPLY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Residential Consumers and Nonresidential Consumers. This service may be taken only in conjunction with the applicable Delivery Service Schedule or Direct Access Delivery Service Schedule. Not applicable to energy usage under Delivery Service Schedule 76 which is billed at Economic Replacement Power rates under Schedule 276 or energy usage under Delivery Service Schedule 47 which is billed at Unscheduled Energy rates under Schedule 247.

Monthly Billing

The Monthly Billing shall be the Energy Charge and/or Demand Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.		Delivery Voltage			
		Secondary	Primary	Transmission	
4	All kWh, per kWh	2.567¢			(I)
5	All kWh, per kWh	2.567¢			(I)
23, 723	First 3,000 kWh, per kWh	2.547¢	2.508¢		(I)
	All additional kWh, per kWh	1.891¢	1.862¢		(I)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 200

BASE SUPPLY SERVICE

Monthly Billing (continued)

Delivery Service Schedule No.		Delivery Voltage			
		Secondary	Primary	Transmission	
28, 728	All kWh, per kWh	2.372¢	2.302¢		(I)
29	All kWh, per kWh	2.372¢	2.372¢		(I)
30, 730	Demand Charge, per kW	$5.24	$4.92		(I)
	All kWh, per kWh	0.857¢	0.777¢		(I)
	Demand shall be as defined in the Delivery Service Schedule				
41, 741	All kWh	2.312¢	2.276¢		(I)
47/48, 747/748	Demand Charge, per kW of On-Peak Demand	$1.42	$1.42	$1.51	(I)
	Per kWh, On-Peak	1.938¢	1.855¢	1.875¢	(I)
	Per kWh, Off-Peak	1.938¢	1.855¢	1.875¢	(I)

Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. All remaining hours are Off-Peak.
On-Peak Demand shall be as defined in the Delivery Service Schedule.

15

Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate Per Lamp	
Level 1	0-5,500	19	$0.52	(I)
Level 2	5,501-12,000	34	$0.92	(I)
Level 3	12-001+	57	$1.54	(I)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 200

BASE SUPPLY SERVICE

Monthly Billing (continued)

Delivery Service Schedule No.

51, 751	**Type of Lamp**	**LED Equivalent Lumens**	**Monthly kWh**	**Rate per Lamp**	
	Level 1	0-3,500	8	$0.19	(I)
	Level 2	3,501-5,500	15	$0.36	
	Level 3	5,501-8,000	25	$0.61	
	Level 4	8,001-12,000	34	$0.82	
	Level 5	12,001-15,500	44	$1.06	
	Level 6	15,501+	57	$1.37	(I)

53, 753	**Types of Luminaire**	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**	
	High Pressure Sodium	5,800	70	31	$0.11	(I)
	High Pressure Sodium	9,500	100	44	$0.15	
	High Pressure Sodium	16,000	150	64	$0.22	
	High Pressure Sodium	22,000	200	85	$0.29	
	High Pressure Sodium	27,500	250	115	$0.39	
	High Pressure Sodium	50,000	400	176	$0.60	
	Metal Halide	9,000	100	39	$0.13	
	Metal Halide	12,000	175	68	$0.23	
	Metal Halide	19,500	250	94	$0.32	
	Metal Halide	32,000	400	149	$0.51	
	Metal Halide	107,800	1,000	354	$1.21	(I)
	Non-Listed Luminaire, per kWh				0.341¢	(I)

54, 754	Per kWh	0.425¢	(I)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 202

RENEWABLE ADJUSTMENT CLAUSE
SUPPLY SERVICE ADJUSTMENT

Purpose

This schedule recovers, between rate cases, the costs to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission.

This adjustment is to recover the actual and forecasted revenue requirement associated with the prudently incurred costs of resources, including associated transmission, that are eligible under Senate Bill 838 (2007) and in service as of the date of the proposed rate change. The revenue requirement includes the actual return of and grossed up return on capital costs of the renewable energy source and associated transmission at the currently authorized rate of return, forecasted operation and maintenance costs, forecasted property taxes, forecasted energy tax credits, and other forecasted costs not captured in the Transition Adjustment Mechanism (TAM). The revenue requirement for Oregon will be calculated using the forecasted inter-jurisdictional allocation factors based on the same 12-month period used in the TAM.

Applicable

To all Residential consumers and Nonresidential consumers except consumers who began service under the five-year cost of service opt-out program described in Schedule 296 before January 1, 2019.

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule.

Schedule		
4	0.000 cents per kWh	(D)(R)
5	0.000 cents per kWh	
15	0.000 cents per kWh	
23, 723	0.000 cents per kWh	
28, 728	0.000 cents per kWh	
30, 730	0.000 cents per kWh	
41, 741	0.000 cents per kWh	
47, 747	0.000 cents per kWh	
48, 748	0.000 cents per kWh	
51, 751	0.000 cents per kWh	
53, 753	0.000 cents per kWh	
54, 754	0.000 cents per kWh	(D)(R)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 203

RENEWABLE RESOURCE DEFERRAL
SUPPLY SERVICE ADJUSTMENT

Purpose

This schedule recovers the costs deferred for renewable resources as authorized by the Commission.

Applicable

To all Residential consumers and Nonresidential consumers except consumers who elected service under the five-year cost of service opt-out program described in Schedule 296 before November 2017.

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule.

Schedule	Charge	
4	0.065 cents per kWh	(I)
5	0.065 cents per kWh	
15	0.034 cents per kWh	
23, 723	0.031 cents per kWh	
28, 728	0.031 cents per kWh	
30, 730	0.031 cents per kWh	
41, 741	0.030 cents per kWh	
47, 747	0.029 cents per kWh	
48, 748	0.029 cents per kWh	
51, 751	0.031 cents per kWh	
53, 753	0.006 cents per kWh	
54, 754	0.008 cents per kWh	(I)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 299

RATE MITIGATION ADJUSTMENT

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No. 36 shall have applied an amount equal to the product of all metered kilowatt-hours multiplied by the following cents per kilowatt hour.

	Secondary	Primary	Transmission	
Schedule 4	(0.365¢)			(N) (C)
Schedule 5	(0.365¢)			
Schedule 15	7.650¢			
Schedule 23, 723	(0.969¢)	(0.969¢)		(N)
Schedule 28, 728	0.225¢	0.554¢		
Schedule 30, 730	0.554¢	0.809¢		
Schedule 41, 741	(3.190¢)	(3.190¢)		
Schedule 47, 747	0.073¢	0.831¢	0.073¢	(N)
Schedule 48, 748	0.073¢	0.831¢	0.073¢	
Schedule 51, 751	8.665¢			
Schedule 53, 753	2.230¢			
Schedule 54, 754	2.900¢			(C)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 300

CHARGES AS DEFINED BY
THE RULES AND REGULATIONS

Service Charges (continued)

Rule No.	Sheet No.	Description	Charge	
11B	R11B-5	**Tampering/Unauthorized Reconnection**	$75.00	
11D	R11D-7	**Non-Remote Service Connection Charge:**		
		Request for reconnect during regular business hours: Monday through Friday, except holidays 8:00 A.M. to 5:00 P.M.	No Charge	
		Request for reconnect during non-regular business hours: Monday through Friday, except holidays 5:00 P.M. to 6:00 P.M.	$75.00	
		Saturday, Sunday & Holidays 8:00 A.M. to 6:00 P.M.	$175.00	
		Remote Service Connection Charge:	No Charge	
11D	R11D-7	**Trouble Call Charge:**	Actual Costs May Be Charged	
11D	R11D-7	**Other Work at Consumer's Request:**	Actual Costs May Be Charged	
13	R13-1	**Capacity Reservation Charge:**	$3.68 per kW	
13	R13-2	**Excess Demand Charge:**	$11.04 per kW	
13	R13-2	**Facilities Charges:**		
		On Facilities at Less than 57,000 Volts		
		Installed at Consumer's expense	0.74% per month	(I)
		Installed at Company's expense	1.57% per month	(I)
		On Facilities at and above 57,000 Volts		
		Installed at Consumer's expense	0.19% per month	(R)
		Installed at Company's expense	0.93% per month	(I)
13	R13-11	**Temporary Service Charge:**		
		Service Drop and Meter only	$164.00	
13	R13-13	**Contract Administration Credit**	$250.00	
21	R21-3	**Pre-Enrollment Usage Information:**		
		Bill Register History per Meter	$2.00 per year	
		Validated Interval Data (15 – 60 minute) per Meter	$10.00 per month	
		Analyzed Interval Meter Data	Cost Based Price	
21	R21-3	**Pre-Enrollment Payment History:**	$2.00 per page	

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 723

GENERAL SERVICE – SMALL NONRESIDENTIAL
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Small Nonresidential Consumers who have chosen to receive electricity from an ESS, and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed, except as provided below for Communication Devices. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Single Phase, per month	$27.40	$27.40	(I)
Three Phase, per month	$40.85	$40.85	(I)
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW, Load Size	$ 2.60	$ 2.60	(I)
Demand Charge, the first 15 kW of demand	No Charge	No Charge	
Demand Charge, for all kW in excess of 15 kW, per kW	$ 8.53	$ 8.42	(I)
Distribution Energy Charge, per kWh	6.299¢	6.202¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.066¢	0.065¢	(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 728

GENERAL SERVICE
LARGE NONRESIDENTIAL 31 KW TO 200 KW
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 50 kW, per month	$ 31.00	$ 38.00	(I)
Load Size 51-100 kW, per month	$ 59.00	$ 66.00	|
Load Size 101 - 300 kW, per month	$140.00	$150.00	|
Load Size > 300 kW, per month	$198.00	$215.00	(I)
Load Size Charge			
≤ 50 kW, per kW Load Size	$ 1.95	$ 2.15	(I)
51-100 kW, per kW Load Size	$ 1.55	$ 1.70	|
101 – 300 kW, per kW Load Size	$ 1.00	$ 1.05	|
> 300 kW, per kW Load Size	$ 0.60	$ 0.50	|
Demand Charge, per kW	$ 6.71	$ 7.39	|
Distribution Energy Charge, per kWh	0.693¢	0.115¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.067¢	0.070¢	(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 730

GENERAL SERVICE
LARGE NONRESIDENTIAL 201 KW TO 999 KW
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 200 kW, per month	$773.00	$625.00	(I, R)
Load Size 201 - 300 kW, per month	$223.00	$195.00	(I, R)
Load Size > 300 kW, per month	$593.00	$510.00	(I, R)
Load Size Charge			
≤ 200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$ 2.75	$ 2.15	(I)
> 300 kW, per kW Load Size	$ 1.35	$ 1.05	(I)
Demand Charge, per kW	$ 6.50	$ 5.40	(I, R)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.071¢	0.072¢	(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW, but not less than 100 kW.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 741

AGRICULTURAL PUMPING SERVICE
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Consumers who have chosen to receive electricity from an ESS and desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

Monthly Billing

Except for November, the Monthly Billing shall be the sum of the Distribution Energy Charge, Reactive Power Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. For November, the billing shall be the sum of the Basic Charge, Load Size Charge, Distribution Energy Charge, Reactive Power Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
Basic Charge (November billing only)	**Secondary**	**Primary**	
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$ 660.00	$ 650.00	(I)
Three Phase Load Size > 300 kW	$2,580.00	$2,550.00	(I)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$ 27.20	$ 26.80	(I)
Three Phase 51 - 300 kW, per kW Load Size	$ 18.60	$ 18.40	
Three Phase > 300 kW, per kW Load Size	$ 11.50	$ 11.30	
Single Phase, Minimum Charge	$ 115.00	$ 115.00	
Three Phase, Minimum Charge	$ 195.00	$ 190.00	
Distribution Energy Charge, per kWh	7.906¢	7.784¢	(I)
Reactive Power Charge, per kVar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.065¢	0.064¢	(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of Company's meter, or by appropriate test, for the 15-minute period of Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

If Motor Size Is:	**Monthly kW is:**
2 hp or less	2 kW
Over 2 through 3 hp	3 kW
Over 3 through 5 hp	5 kW
Over 5 through 7.5 hp	7 kW
Over 7.5 through 10 hp	9 kW

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 747

LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Reserves Charges, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
Distribution Charge	**Secondary**	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$950.00	$1,130.00	$1,790.00	(I)
Facility Capacity > 4,000 kW, per month	$2,620.00	$3,120.00	$4,590.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$4.05	$1.35	$1.40	(I)
> 4,000 kW, per kW Facility Capacity	$1.60	$0.55	$1.20	(I)
On-Peak Demand Charge, per kW	$6.34	$6.11	$6.22	(I, R, I)
Reactive Power Charges				
Per kVar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.43	N/A	
Reserves Charges				
Spinning Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company-approved Self-Supply Agreement)				
per kW of Self-Supplied Spinning Reserves	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves				
(with Company-approved load reduction plan or Self-Supply Agreement)				
per kW of approved load reduction kW	($0.27)	($0.27)	($0.27)	
System Usage Charge				
Schedule 200 Related, per kWh	0.068¢	0.074¢	0.066¢	

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 748

LARGE GENERAL SERVICE 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS, to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until Consumer fails to meet or exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 747.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**			
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$950.00	$1,130.00	$1,790.00	(I)
Facility Capacity > 4000 kW, per month	$2,620.00	$3,120.00	$4,590.00	(I)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$4.05	$1.35	$1.40	(I)
> 4000 kW, per kW Facility Capacity	$1.60	$0.55	$1.20	(I)
On-Peak Demand Charge, per kW	$6.34	$6.11	$6.22	(I, R, I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.43	N/A	
System Usage Charge				
Schedule 200 Related, per kWh	0.068¢	0.074¢	0.066¢	(I)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 751

STREET LIGHTING SERVICE COMPANY-OWNED SYSTEM
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

The Monthly Billing shall be the rate per luminaire as specified in the rate tables below plus the applicable adjustments as specified in Schedule 90.

Type of Lamp	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6	
LED Equivalent Lumens	0-3,500	3,501-5,500	5,501-8,000	8,001-12,000	12,001-15,500	15,501+	
Monthly kWh	8	15	25	34	44	57	
Functional Lighting	$ 6.37	$ 6.75	$ 6.85	$ 6.95	$ 7.37	$ 8.98	(R)
Functional Lighting - Customer Funded Conversion	$ 3.42	$ 3.60	$ 3.69	$ 3.75	$ 4.00	$ 4.90	(R)
Decorative Series	N/A	$ 11.65	$ 11.73	N/A	N/A	N/A	(R)

Functional Lighting: Common less expensive luminaires that may be mounted either on wood, fiberglass or non-decorative metal poles. The Company will maintain a list of functional light fixtures that are available.

Customer-Funded Conversion: Street lights that have been converted to LED from another lighting type and whose conversion was funded by the Customer.

Decorative Series Lighting: More stylish luminaires mounted vertically on decorative metal poles. The Company will maintain a listing of standard decorative street light fixtures that are available under this Schedule.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this Schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, and distribution charges are collected through rates in this schedule.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 753

STREET LIGHTING SERVICE CONSUMER-OWNED SYSTEM
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Consumer owned street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

Energy Only Service - Rate per Luminaire

Energy Only Service includes energy supplied from Company's overhead or underground circuits and does not include any maintenance to Consumer's facilities. Maintenance service will be provided only as indicated in the Maintenance Service section below.

The Monthly Billing shall be the rate per luminaire specified in the rate tables below plus the applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor						
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000
Watts	70	100	150	200	250	400
Monthly kWh	31	44	64	85	115	176
Energy Only Service	$ 1.31	$ 1.85	$ 2.70	$ 3.58	$ 4.84	$ 7.41

(I)

Metal Halide					
Lumen Rating	9,000	12,000	19,500	32,000	107,800
Watts	100	175	250	400	1,000
Monthly kWh	39	68	94	149	354
Energy Only Service	$ 1.64	$ 2.86	$ 3.96	$ 6.28	$ 14.91

(I)

For non-listed luminaires the cost will be calculated for 4167 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh
Energy Only Service	4.213

(I)

Maintenance Service (No New Service)

Where the utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for operation and maintenance will be added to the Energy Only Service rates listed above. Monthly Maintenance is only applicable for existing monthly maintenance service agreements in effect prior to May 24, 2006.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 754

RECREATIONAL FIELD LIGHTING - RESTRICTED
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At Consumer's option, service for recreational field lighting may be taken under Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge

Basic Charge, Single Phase, per month	$	6.00	
Basic Charge, Three Phase, per month	$	9.00	
Distribution Energy Charge, per kWh		4.642¢	(I)

System Usage Charge

Schedule 200 Related, per kWh		0.013¢	(I)

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

Special Conditions

Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 776R

LARGE GENERAL SERVICE - PARTIAL REQUIREMENTS
SERVICE-ECONOMIC REPLACEMENT SERVICE RIDER
DIRECT ACCESS DELIVERY SERVICE

Purpose

To provide Consumers served on Schedule 747 with the opportunity of purchasing Energy from an ESS to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement service except as explicitly agreed to between Company and Consumer.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers receiving Delivery Service under Schedule 747.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 747 plus the applicable adjustments as specified in Schedule 90:

	Delivery Voltage			
	Secondary	Primary	Transmission	
Daily ERS Demand Charge				
per kW of Daily ERS On-Peak Demand	$0.247	$0.238	$0.242	(I)(R)(I)

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

ERS and ENF

Economic Replacement Service (ERS) is Electricity supplied by an ESS to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Service Agreement (ERSA).

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 848

LARGE GENERAL SERVICE 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE – DISTRIBUTION ONLY

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS and are participating in the New Large Load Direct Access Program in Schedule 293 or to existing consumers who have completed the five-year transition period for the Five-Year Cost of Service Opt-Out in Schedule 296. Existing consumers who have completed the five-year transition period for the Five-Year Cost of Service Opt-Out in Schedule 296 must have electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until Consumer fails to meet or exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the Distribution Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**			
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$950.00	$1,130.00	$1,790.00	(I)
Facility Capacity > 4000 kW, per month	$2,620.00	$3,120.00	$4,590.00	(I)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$4.05	$1.35	$1.40	(I)
> 4000 kW, per kW Facility Capacity	$1.60	$0.55	$1.20	(I)
On-Peak Demand Charge, per kW	$6.34	$6.11	$6.22	(I, R, I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.43	N/A	

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

(continued)

Docket No. UE 470
Exhibit PAC/1004
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Target Functionalized Revenues, Billing Determinants and Proposed Base Rates

May 2026

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues
Forecast 12 Months Ended December 31, 2027

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]	$47,151	$67,282	$67,282	$67,295
	System Usage- Schedule 200 Related	$3,571	$4,042	$4,042	$4,018
	System Usage- T&A and Schedule 201 Related	$7,087	$7,305	$7,305	$7,310
	Distribution	$384,706	$469,513	$469,513	$469,514
	Other Adjustments	$15,010	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$132,693	$143,240	$143,240	$143,239
	Generation Energy - Net Power Costs (Sch 201)	$211,057	$191,585	$211,057	$211,057
	Total	$801,275	$882,967	$902,439	$902,432
Schedule 23, Small General Service					
	Transmission & Ancillary Services[1]	$11,535	$11,576	$11,576	$11,580
	System Usage- Schedule 200 Related	$642	$736	$736	$731
	System Usage- T&A and Schedule 201 Related	$1,362	$1,303	$1,303	$1,306
	Distribution	$84,138	$109,684	$109,684	$109,682
	Other Adjustments	$2,812	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$24,721	$26,665	$26,665	$26,669
	Generation Energy - Net Power Costs (Sch 201)	$39,483	$35,664	$39,483	$39,483
	Total	$164,694	$185,628	$189,447	$189,450
Schedule 28, General Service 31-200kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$11,785	$19,722	$19,722	$19,709
	System Usage- Schedule 200 Related	$1,212	$1,319	$1,319	$1,309
	System Usage- T&A and Schedule 201 Related	$2,365	$2,325	$2,325	$2,326
	Distribution	$60,773	$79,546	$79,546	$79,578
	Other Adjustments	$4,925	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$43,174	$46,368	$46,368	$46,360
	Generation Energy - Net Power Costs (Sch 201)	$69,051	$62,017	$69,051	$69,051
	Total	$193,285	$211,296	$218,330	$218,333
Primary Voltage					
	Transmission & Ancillary Services[1]	$126	$167	$167	$167
	System Usage- Schedule 200 Related	$9	$12	$12	$12
	System Usage- T&A and Schedule 201 Related	$19	$21	$21	$21
	Distribution	$573	$644	$644	$644
	Other Adjustments	$44	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$373	$401	$401	$401
	Generation Energy - Net Power Costs (Sch 201)	$597	$536	$597	$597
	Total	$1,741	$1,782	$1,842	$1,842
Schedule 30, General Service 201-999kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$8,250	$11,536	$11,536	$11,549
	System Usage- Schedule 200 Related	$705	$849	$849	$848
	System Usage- T&A and Schedule 201 Related	$1,385	$1,487	$1,487	$1,493
	Distribution	$29,592	$33,401	$33,401	$33,327
	Other Adjustments	$2,950	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$25,798	$27,822	$27,822	$27,878
	Generation Energy - Net Power Costs (Sch 201)	$41,509	$37,212	$41,509	$41,509
	Total	$110,188	$112,308	$116,605	$116,603
Primary Voltage					
	Transmission & Ancillary Services[1]	$516	$680	$680	$681
	System Usage- Schedule 200 Related	$46	$55	$55	$55
	System Usage- T&A and Schedule 201 Related	$89	$95	$95	$95
	Distribution	$1,828	$1,816	$1,816	$1,818
	Other Adjustments	$188	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$1,632	$1,700	$1,700	$1,699
	Generation Energy - Net Power Costs (Sch 201)	$2,565	$2,274	$2,565	$2,565
	Total	$6,863	$6,621	$6,911	$6,911
Schedule 41, Agricultural Pumping Service					
	Transmission & Ancillary Services[1]	$1,488	$2,141	$2,141	$2,141
	System Usage- Schedule 200 Related	$120	$148	$148	$147
	System Usage- T&A and Schedule 201 Related	$233	$258	$258	$257
	Distribution	$20,112	$23,555	$23,555	$23,559
	Other Adjustments	$544	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$4,764	$5,221	$5,221	$5,220
	Generation Energy - Net Power Costs (Sch 201)	$7,635	$6,983	$7,635	$7,635
	Total	$34,896	$38,306	$38,958	$38,959

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues
Forecast 12 Months Ended December 31, 2027

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]	$3,468	$5,056	$5,056	$5,049
	System Usage- Schedule 200 Related	$328	$374	$374	$372
	System Usage- T&A and Schedule 201 Related	$640	$651	$651	$651
	Distribution	$13,270	$15,757	$15,757	$15,791
	Other Adjustments	$1,253	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$11,470	$12,523	$12,523	$12,495
	Generation Energy - Net Power Costs (Sch 201)	$18,605	$16,750	$18,605	$18,605
	Total	$49,035	$51,109	$52,964	$52,963
Primary Voltage					
	Transmission & Ancillary Services[1]	$20,166	$22,943	$22,943	$22,941
	System Usage- Schedule 200 Related	$1,543	$2,047	$2,047	$2,039
	System Usage- T&A and Schedule 201 Related	$2,976	$3,521	$3,521	$3,527
	Distribution	$55,168	$45,130	$45,130	$45,238
	Other Adjustments	$6,310	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$57,773	$59,976	$59,976	$59,872
	Generation Energy - Net Power Costs (Sch 201)	$90,763	$80,219	$90,763	$90,763
	Total	$234,699	$213,835	$224,379	$224,380
Transmission Voltage					
	Transmission & Ancillary Services[1]	$13,563	$19,955	$19,955	$19,937
	System Usage- Schedule 200 Related	$1,372	$1,664	$1,664	$1,677
	System Usage- T&A and Schedule 201 Related	$2,668	$2,850	$2,850	$2,846
	Distribution	$27,313	$28,002	$28,002	$27,992
	Other Adjustments	$5,818	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$48,483	$53,210	$53,210	$53,233
	Generation Energy - Net Power Costs (Sch 201)	$78,651	$71,169	$78,651	$78,651
	Total	$177,868	$176,850	$184,332	$184,336
Schedules 15, 51, 53, 54 Lighting					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$19	$71	$71	$70
	System Usage- Schedule 200 Related	$8	$10	$10	$9
	System Usage- T&A and Schedule 201 Related	$14	$15	$15	$14
	Distribution	$3,785	$3,786	$3,786	$3,785
	Other Adjustments	$60	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$283	$307	$307	$307
	Generation Energy - Net Power Costs (Sch 201)	$476	$411	$476	$476
	Total	$4,645	$4,599	$4,665	$4,662
TOTAL		**$1,779,189**	**$1,885,301**	**$1,940,873**	**$1,940,873**
	Employee Discount	-$463		-$521	-$521
Additional Rate Schedules					
	Schedule 29	$216		$260	$260
	Schedule 47	$4,676		$4,569	$4,569
	Schedule 848	$1,920		$1,968	$1,968
Total Oregon		**$1,785,538**		**$1,947,149**	**$1,947,149**
			Base Revenue Increase	**$161,611**	**$161,611**

[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, 2025
Forecast 12 Months Ended December 31, 2027

Schedule	Actual 7/24-6/25 Units	Normalized 7/24-6/25 Units	Forecast 1/27 - 12/27 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 4 - Composite								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	5,727,645,310	5,600,886,633	5,580,023,438	kWh	0.845 ¢	$47,151,198	1.206 ¢	$67,295,083
System Usage Charge								
Sch 200 related, per kWh	5,727,645,310	5,600,886,633	5,580,023,438	kWh	0.064 ¢	$3,571,215	0.072 ¢	$4,017,617
T&A and Sch 201 related, per kWh	5,727,645,310	5,600,886,633	5,580,023,438	kWh	0.127 ¢	$7,086,630	0.131 ¢	$7,309,831
Distribution Charge								
Basic Charge Single Family, per month	5,121,118	5,121,118	5,242,989	bill	$14.00	$73,401,846	$17.00	$89,130,813
Basic Charge Multi Family, per month	1,415,532	1,415,532	1,449,218	bill	$8.00	$11,593,744	$9.00	$13,042,962
Total Bills	6,536,650	6,536,650	6,692,207	bill				
Add'l Basic Charge 3 phase, per month	7,025	7,025	7,025	bill	$9.00	$63,225	$9.00	$63,225
Distribution Energy Charge, per kWh	5,727,645,310	5,600,886,633	5,580,023,438	kWh	5.370 ¢	$299,647,259	6.582 ¢	$367,277,143
Energy Charge - Schedule 200								
per kWh	5,727,645,310	5,600,886,633	5,580,023,438	kWh	2.378 ¢	$132,692,957	2.567 ¢	$143,239,202
Subtotal	5,727,645,310	5,600,886,633	5,580,023,438	kWh		$575,208,074		$691,375,876
Renewable Adjustment Clause (202), per kWh	5,727,645,310	5,600,886,633	5,580,023,438	kWh	0.269 ¢	$15,010,263	0.000 ¢	$0
Subtotal						$590,218,337		$691,375,876
Schedule 201								
per kWh	5,727,645,310	5,600,886,633	5,580,023,438	kWh	3.777 ¢	$210,757,485	3.777 ¢	$210,757,485
TOU Opt. On Peak Adder, per On-peak kWh	4,593,352	4,593,352	4,576,242	kWh	14.270 ¢	$653,030	14.270 ¢	$653,030
TOU Opt. Off Peak Adder, per Off-peak kWh	9,373,810	9,373,810	9,338,893	kWh	-3.790 ¢	($353,944)	-3.790 ¢	($353,944)
Total	5,727,645,310	5,600,886,633	5,580,023,438	kWh		$801,274,908		$902,432,447
							Change	$101,157,539
Schedule No. 4 (Employee Discount)								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	13,218,308	13,218,308	13,169,070	kWh	0.845 ¢	$111,279	1.206 ¢	$158,819
System Usage Charge								
Sch 200 related, per kWh	13,218,308	13,218,308	13,169,070	kWh	0.064 ¢	$8,428	0.072 ¢	$9,482
T&A and Sch 201 related, per kWh	13,218,308	13,218,308	13,169,070	kWh	0.127 ¢	$16,725	0.131 ¢	$17,251
Distribution Charge								
Basic Charge Single Family, per month	10,828	10,828	11,086	bill	$14.00	$155,204	$17.00	$188,462
Basic Charge Multi Family, per month	635	635	650	bill	$8.00	$5,200	$9.00	$5,850
Total Bills	11,463	11,463	11,736	bill				
Distribution Energy Charge, per kWh	13,218,308	13,218,308	13,169,070	kWh	5.370 ¢	$707,179	6.582 ¢	$866,788
Energy Charge - Schedule 200								
per kWh	13,218,308	13,218,308	13,169,070	kWh	2.378 ¢	$313,160	2.567 ¢	$338,050
Subtotal	13,218,308	13,218,308	13,169,070	kWh		$1,317,175		$1,584,702
Renewable Adjustment Clause (202), per kWh	13,218,308	13,218,308	13,169,070	kWh	0.269 ¢	$35,425	0.000 ¢	$0
Subtotal						$1,352,600		$1,584,702
Schedule 201								
per kWh	13,218,308	13,218,308	13,169,070	kWh	3.777 ¢	$497,396	3.777 ¢	$497,396
TOU Opt. On Peak Adder, per On-peak kWh	12,448	12,448	12,402	kWh	14.270 ¢	$1,770	14.270 ¢	$1,770
TOU Opt. Off Peak Adder, per Off-peak kWh	26,488	26,488	26,389	kWh	-3.790 ¢	($1,000)	-3.790 ¢	($1,000)
Total	13,218,308	13,218,308	13,169,070	kWh		$1,850,766		$2,082,868
Schedule 202 Employee Discount						($8,856)		$0
Schedule 201 Employee Discount						($124,542)		($124,542)
Total Employee Discount						($462,692)		($520,717)
							Change	($58,025)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2025
Forecast 12 Months Ended December 31, 2027

Schedule	Actual 7/24-6/25 Units	Normalized 7/24-6/25 Units	Forecast 1/27 - 12/27 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 23/723 - Composite								
General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	1,189,693,646	1,182,670,038	1,104,233,474	kWh	1.042 ¢	$11,506,113	1.046 ¢	$11,550,282
System Usage Charge								
Sch 200 related, per kWh	1,189,693,646	1,182,670,038	1,104,233,474	kWh	0.058 ¢	$640,455	0.066 ¢	$728,794
T&A and Sch 201 related, per kWh	1,189,693,646	1,182,670,038	1,104,233,474	kWh	0.123 ¢	$1,358,207	0.118 ¢	$1,302,995
Distribution Charge								
Basic Charge								
Single Phase, per month	800,332	800,332	804,002	bill	$21.00	$16,884,042	$27.40	$22,029,655
Three Phase, per month	255,882	255,882	256,752	bill	$31.35	$8,049,175	$40.85	$10,488,319
Load Size Charge								
≤ 15 kW					No Charge		No Charge	
per kW for all kW in excess of 15 kW	1,169,597	1,169,597	1,090,957	kW	$2.00	$2,181,914	$2.60	$2,836,488
Demand Charge, the first 15 kW of demand					No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	555,379	555,379	517,933	kW	$6.54	$3,387,282	$8.53	$4,417,968
Reactive Power Charge, per kvar	212,635	212,635	197,729	kvar	65.00 ¢	$128,524	65.00 ¢	$128,524
Distribution Energy Charge, per kWh	1,189,693,646	1,182,670,038	1,104,233,474	kWh	4.830 ¢	$53,334,477	6.299 ¢	$69,555,667
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	940,033,855	934,272,855	873,058,510	kWh	2.361 ¢	$20,612,911	2.547 ¢	$22,236,800
All additional kWh, per kWh	249,659,791	248,397,183	231,174,964	kWh	1.753 ¢	$4,052,497	1.891 ¢	$4,371,519
Subtotal	1,189,693,646	1,182,670,038	1,104,233,474	kWh		$122,135,597		$149,647,011
Renewable Adjustment Clause (202), per kWh	1,189,693,646	1,182,670,038	1,104,233,474	kWh	0.254 ¢	$2,804,753	0.000 ¢	$0
Subtotal						$124,940,350		$149,647,011
Schedule 201								
1st 3,000 kWh, per kWh	940,033,855	934,272,855	873,058,510	kWh	3.772 ¢	$32,931,767	3.772 ¢	$32,931,767
All additional kWh, per kWh	249,659,791	248,397,183	231,174,964	kWh	2.797 ¢	$6,465,964	2.797 ¢	$6,465,964
TOU Opt. On Peak Adder, per On-peak kWh	380,723	380,723	353,808	kWh	12.578 ¢	$44,502	12.578 ¢	$44,502
TOU Opt. Off Peak Adder, per Off-peak kWh	2,008,188	2,008,188	1,866,100	kWh	-2.532 ¢	($47,250)	-2.532 ¢	($47,250)
Total	1,189,693,646	1,182,670,038	1,104,233,474	kWh		$164,335,333		$189,041,994
							Change	$24,706,661
Schedule No. 23/723 - Composite								
General Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	3,074,858	3,074,858	2,854,845	kWh	1.026 ¢	$29,291	1.030 ¢	$29,405
System Usage Charge								
Sch 200 related, per kWh	3,074,858	3,074,858	2,854,845	kWh	0.057 ¢	$1,627	0.065 ¢	$1,856
T&A and Sch 201 related, per kWh	3,074,858	3,074,858	2,854,845	kWh	0.121 ¢	$3,454	0.116 ¢	$3,312
Distribution Charge								
Basic Charge								
Single Phase, per month	258	258	259	bill	$21.00	$5,439	$27.40	$7,097
Three Phase, per month	510	510	512	bill	$31.35	$16,051	$40.85	$20,915
Load Size Charge								
≤ 15 kW					No Charge		No Charge	
per kW for all kW in excess of 15 kW	3,534	3,534	3,283	kW	$2.00	$6,566	$2.60	$8,536
Demand Charge, the first 15 kW of demand					No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	1,235	1,235	1,147	kW	$6.45	$7,398	$8.42	$9,658
Reactive Power Charge, per kvar	2,955	2,955	2,744	kvar	60.00 ¢	$1,646	60.00 ¢	$1,646
Distribution Energy Charge, per kWh	3,074,858	3,074,858	2,854,845	kWh	4.755 ¢	$135,748	6.202 ¢	$177,057
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	1,212,382	1,212,382	1,125,258	kWh	2.324 ¢	$26,151	2.508 ¢	$28,221
All additional kWh, per kWh	1,862,476	1,862,476	1,729,587	kWh	1.726 ¢	$29,853	1.862 ¢	$32,205
Subtotal	3,074,858	3,074,858	2,854,845	kWh		$263,224		$319,908
Renewable Adjustment Clause (202), per kWh	3,074,858	3,074,858	2,854,845	kWh	0.254 ¢	$7,251	0.000 ¢	$0
Subtotal						$270,475		$319,908
Schedule 201								
1st 3,000 kWh, per kWh	1,212,382	1,212,382	1,125,258	kWh	3.659 ¢	$41,173	3.659 ¢	$41,173
All additional kWh, per kWh	1,862,476	1,862,476	1,729,587	kWh	2.713 ¢	$46,924	2.713 ¢	$46,924
TOU Opt. On Peak Adder, per On-peak kWh	0	0	0	kWh	12.578 ¢	$0	12.578 ¢	$0
TOU Opt. Off Peak Adder, per Off-peak kWh	0	0	0	kWh	-2.532 ¢	$0	-2.532 ¢	$0
Total	3,074,858	3,074,858	2,854,845	kWh		$358,572		$408,005
							Change	$49,433

PACIFIC POWER
State of Oregon
Billing Determinants
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Forecast 12 Months Ended December 31, 2027

Schedule	Actual 7/24-6/25 Units	Normalized 7/24-6/25 Units	Forecast 1/27 - 12/27 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 28/728 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	6,938,945	6,938,945	6,772,883	kW	$1.74	$11,784,816	$2.91	$19,709,090
System Usage Charge								
Sch 200 related, per kWh	2,009,942,261	2,001,739,569	1,954,460,009	kWh	0.062 ¢	$1,211,765	0.067 ¢	$1,309,488
T&A and Sch 201 related, per kWh	2,009,942,261	2,001,739,569	1,954,460,009	kWh	0.121 ¢	$2,364,897	0.119 ¢	$2,325,807
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	57,265	57,265	58,783	bill	$24.00	$1,410,792	$31.00	$1,822,273
Load Size 51-100 kW, per month	41,436	41,436	42,533	bill	$45.00	$1,913,985	$59.00	$2,509,447
Load Size 101-300 kW, per month	23,741	23,741	24,362	bill	$107.00	$2,606,734	$140.00	$3,410,680
Load Size > 300 kW, per month	856	856	879	bill	$151.00	$132,729	$198.00	$174,042
Load Size Charge								
≤ 50 kW, per kW	2,203,430	2,203,430	2,152,108	kW	$1.50	$3,228,162	$1.95	$4,196,611
51-100 kW, per kW	2,895,240	2,895,240	2,825,243	kW	$1.20	$3,390,292	$1.55	$4,379,127
101-300 kW, per kW	3,593,810	3,593,810	3,507,453	kW	$0.75	$2,630,590	$1.00	$3,507,453
>300 kW, per kW	377,074	377,074	367,655	kW	$0.45	$165,445	$0.60	$220,593
Demand Charge, per kW	6,938,945	6,938,945	6,772,883	kW	$5.13	$34,744,890	$6.71	$45,446,045
Reactive Power Charge, per kvar	579,805	579,805	564,430	kvar	65.00 ¢	$366,880	65.00 ¢	$366,880
Distribution Energy Charge, per kWh	2,009,942,261	2,001,739,569	1,954,460,009	kWh	0.521 ¢	$10,182,737	0.693 ¢	$13,544,408
Energy Charge - Schedule 200								
All kWh, per kWh	2,009,942,261	2,001,739,569	1,954,460,009	kWh	2.209 ¢	$43,174,022	2.372 ¢	$46,359,791
Subtotal	2,009,942,261	2,001,739,569	1,954,460,009	kWh		$119,308,736		$149,281,735
Renewable Adjustment Clause (202), per kWh	2,009,942,261	2,001,739,569	1,954,460,009	kWh	0.252 ¢	$4,925,239	0.000 ¢	$0
Subtotal						$124,233,975		$149,281,735
Schedule 201								
All kWh, per kWh	2,009,942,261	2,001,739,569	1,954,460,009	kWh	3.533 ¢	$69,051,072	3.533 ¢	$69,051,072
Total	2,009,942,261	2,001,739,569	1,954,460,009	kWh		$193,285,047		$218,332,807
							Change	$25,047,760
Schedule No. 28/728 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	60,836	60,836	59,183	kW	$2.13	$126,060	$2.82	$166,896
System Usage Charge								
Sch 200 related, per kWh	17,905,525	17,905,525	17,420,933	kWh	0.054 ¢	$9,407	0.070 ¢	$12,195
T&A and Sch 201 related, per kWh	17,905,525	17,905,525	17,420,933	kWh	0.107 ¢	$18,640	0.123 ¢	$21,428
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	113	113	116	bill	$34.00	$3,944	$38.00	$4,408
Load Size 51-100 kW, per month	206	206	211	bill	$59.00	$12,449	$66.00	$13,926
Load Size 101-300 kW, per month	320	320	328	bill	$134.00	$43,952	$150.00	$49,200
Load Size > 300 kW, per month	46	46	47	bill	$191.00	$8,977	$215.00	$10,105
Load Size Charge								
≤ 50 kW, per kW	4,287	4,287	4,173	kW	$1.90	$7,929	$2.15	$8,972
51-100 kW, per kW	14,971	14,971	14,543	kW	$1.50	$21,815	$1.70	$24,723
101-300 kW, per kW	55,240	55,240	53,765	kW	$0.95	$51,077	$1.05	$56,453
>300 kW, per kW	22,650	22,650	22,004	kW	$0.45	$9,902	$0.50	$11,002
Demand Charge, per kW	60,836	60,836	59,183	kW	$6.58	$389,424	$7.39	$437,362
Reactive Power Charge, per kvar	13,195	13,195	12,829	kvar	60.00 ¢	$7,697	60.00 ¢	$7,697
Distribution Energy Charge, per kWh	17,905,525	17,905,525	17,420,933	kWh	0.092 ¢	$16,027	0.115 ¢	$20,034
Energy Charge - Schedule 200								
All kWh, per kWh	17,905,525	17,905,525	17,420,933	kWh	2.139 ¢	$372,634	2.302 ¢	$401,030
Subtotal	17,905,525	17,905,525	17,420,933	kWh		$1,099,934		$1,245,431
Renewable Adjustment Clause (202), per kWh	17,905,525	17,905,525	17,420,933	kWh	0.252 ¢	$43,901	0.000 ¢	$0
Subtotal						$1,143,835		$1,245,431
Schedule 201								
All kWh, per kWh	17,905,525	17,905,525	17,420,933	kWh	3.425 ¢	$596,667	3.425 ¢	$596,667
Total	17,905,525	17,905,525	17,420,933	kWh		$1,740,502		$1,842,098
							Change	$101,596
Schedule No. 29- Composite								
Large General Service TOU								
Transmission & Ancillary Services Charge								
per kWh	1,154,436	1,154,436	1,126,300	kWh	0.582 ¢	$6,555	0.974 ¢	$10,970
System Usage Charge								
Sch 200 related, per kWh	1,154,436	1,154,436	1,126,300	kWh	0.062 ¢	$698	0.067 ¢	$755
T&A and Sch 201 related, per kWh	1,154,436	1,154,436	1,126,300	kWh	0.121 ¢	$1,363	0.119 ¢	$1,340
Distribution Charge								
Basic Charge	190	190	195	bill	$48.00	$9,360	$62.85	$12,256
Distribution Energy Charge								
First Block, first 50 kWh per kW demand, per kWh	596,407	596,407	581,899	kWh	24.097 ¢	$140,220	31.049 ¢	$180,674
All Additional kWh, per kWh	558,029	558,029	544,401	kWh	-1.699 ¢	($9,249)	-1.699 ¢	($9,249)
Energy Charge - Schedule 200								
All kWh, per kWh	1,154,436	1,154,436	1,126,300	kWh	2.209 ¢	$24,880	2.372 ¢	$26,716
Subtotal	1,154,436	1,154,436	1,126,300	kWh		$173,827		$223,462
Renewable Adjustment Clause (202), per kWh	1,154,436	1,154,436	1,126,300	kWh	0.252 ¢	$2,838	0.000 ¢	$0
Subtotal						$176,665		$223,462
Schedule 201								
All kWh, per kWh	1,154,436	1,154,436	1,126,300	kWh	3.533 ¢	$39,792	3.533 ¢	$39,792
TOU On Peak Adder, per On-peak kWh	166,244	166,244	162,201	kWh	13.014 ¢	$21,109	13.014 ¢	$21,109
TOU Off Peak Adder, per Off-peak kWh	988,192	988,192	964,099	kWh	-2.532 ¢	($24,411)	-2.532 ¢	($24,411)
Total	1,154,436	1,154,436	1,126,300	kWh		$216,457		$259,952
					Change		Change	$43,495

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2025
Forecast 12 Months Ended December 31, 2027

Schedule	Actual 7/24-6/25 Units	Normalized 7/24-6/25 Units	Forecast 1/27 - 12/27 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 30/730 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	3,344,036	3,344,036	3,367,172	kW	$2.45	$8,249,571	$3.43	$11,549,400
System Usage Charge								
Sch 200 related, per kWh	1,188,221,334	1,183,683,431	1,194,154,340	kWh	0.059 ¢	$704,551	0.071 ¢	$847,850
T&A and Sch 201 related, per kWh	1,188,221,334	1,183,683,431	1,194,154,340	kWh	0.116 ¢	$1,385,219	0.125 ¢	$1,492,693
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	168	168	172	bill	$688.00	$118,336	$773.00	$132,956
Load Size 201-300 kW, per month	2,513	2,513	2,574	bill	$198.00	$509,652	$223.00	$574,002
Load Size > 300 kW, per month	6,607	6,607	6,769	bill	$525.00	$3,553,725	$593.00	$4,014,017
Load Size Charge								
≤ 200 Kw, per kW					No Charge	$0	No Charge	$0
201-300 kW, per kW	654,384	654,384	659,897	kW	$2.45	$1,616,748	$2.75	$1,814,717
>300 kW, per kW	3,350,355	3,350,355	3,374,073	kW	$1.20	$4,048,888	$1.35	$4,554,999
Demand Charge, per kW	3,344,036	3,344,036	3,367,172	kW	$5.76	$19,394,911	$6.50	$21,886,618
Reactive Power Charge, per kvar	539,807	539,807	537,566	kvar	65.00 ¢	$349,418	65.00 ¢	$349,418
Energy Charge - Schedule 200								
Demand Charge, per kW	3,344,036	3,344,036	3,367,172	kW	$4.86	$16,364,456	$5.24	$17,643,981
All kWh, per kWh	1,188,221,334	1,183,683,431	1,194,154,340	kWh	0.790 ¢	$9,433,819	0.857 ¢	$10,233,903
Subtotal	1,188,221,334	1,183,683,431	1,194,154,340	kWh		$65,729,294		$75,094,554
Renewable Adjustment Clause (202), per kWh	1,188,221,334	1,183,683,431	1,194,154,340	kWh	0.247 ¢	$2,949,561	0.000 ¢	$0
Subtotal						$68,678,855		$75,094,554
Schedule 201								
All kWh, per kWh	1,188,221,334	1,183,683,431	1,194,154,340	kWh	3.476 ¢	$41,508,805	3.476 ¢	$41,508,805
Total	1,188,221,334	1,183,683,431	1,194,154,340	kWh		$110,187,660		$116,603,359
							Change	$6,415,699
Schedule No. 30/730 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	224,923	224,923	225,335	kW	$2.29	$516,017	$3.02	$680,512
System Usage Charge								
Sch 200 related, per kWh	75,739,701	75,739,701	75,921,624	kWh	0.060 ¢	$45,553	0.072 ¢	$54,664
T&A and Sch 201 related, per kWh	75,739,701	75,739,701	75,921,624	kWh	0.117 ¢	$88,828	0.125 ¢	$94,902
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	1	1	1	bill	$626.00	$626	$625.00	$625.00
Load Size 201-300 kW, per month	101	101	104	bill	$196.00	$20,384	$195.00	$20,280.00
Load Size > 300 kW, per month	438	438	450	bill	$513.00	$230,850	$510.00	$229,500.00
Load Size Charge								
≤ 200 Kw, per kW					No Charge		No Charge	
201-300 kW, per kW	26,699	26,699	26,784	kW	$2.15	$57,586	$2.15	$57,586
>300 kW, per kW	256,332	256,332	256,904	kW	$1.05	$269,749	$1.05	$269,749
Demand Charge, per kW	224,923	224,923	225,335	kW	$5.44	$1,225,822	$5.40	$1,216,809
Reactive Power Charge, per kvar	39,273	39,273	38,675	kvar	60.00 ¢	$23,205	60.00 ¢	$23,205
Energy Charge - Schedule 200								
Demand Charge, per kW	224,923	224,923	225,335	kW	$4.72	$1,063,581	$4.92	$1,108,648
All kWh, per kWh	75,739,701	75,739,701	75,921,624	kWh	0.749 ¢	$568,653	0.777 ¢	$589,911
Subtotal	75,739,701	75,739,701	75,921,624	kWh		$4,110,854		$4,346,391
Renewable Adjustment Clause (202), per kWh	75,739,701	75,739,701	75,921,624	kWh	0.247 ¢	$187,526	0.000 ¢	$0
Subtotal						$4,298,380		$4,346,391
Schedule 201								
All kWh, per kWh	75,739,701	75,739,701	75,921,624	kWh	3.378 ¢	$2,564,632	3.378 ¢	$2,564,632
Total	75,739,701	75,739,701	75,921,624	kWh		$6,863,012		$6,911,023
							Change	$48,011

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2025
Forecast 12 Months Ended December 31, 2027

Schedule	Actual 7/24-6/25 Units	Normalized 7/24-6/25 Units	Forecast 1/27 - 12/27 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 41/741 - Irrigation								
Agricultural Pumping Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	205,868,661	206,890,825	225,796,414	kWh	0.659 ¢	$1,487,998	0.948 ¢	$2,140,550
System Usage Charge								
Sch 200 related, per kWh	205,868,661	206,890,825	225,796,414	kWh	0.053 ¢	$119,672	0.065 ¢	$146,768
T&A and Sch 201 related, per kWh	205,868,661	206,890,825	225,796,414	kWh	0.103 ¢	$232,570	0.114 ¢	$257,408
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	5,363	5,363	5,245	bill	No Charge	$0	No Charge	$0
Three Phase Load Size 51 - 300 kW, per customer	924	924	904	bill	$560.00	$506,240	$660.00	$596,640
Three Phase Load Size > 300 kW, per customer	20	20	20	bill	$2,200.00	$44,000	$2,580.00	$51,600
Total Annual Bills	6,307	6,307	6,169					
Average Customers	7,984	7,984	7,808					
Monthly Bills	53,331	53,331	52,153					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	89,692	89,692	97,888	kW	$23.20	$2,271,002	$27.20	$2,662,554
Three Phase Load Size 51-300 kW, per kW	83,130	83,130	90,726	kW	$15.90	$1,442,543	$18.60	$1,687,504
Three Phase Load Size > 300 kW, per kW	8,155	8,155	8,900	kW	$9.80	$87,220	$11.50	$102,350
Single Phase, Minimum Charge	668	668	653	bill	$100.00	$65,300	$115.00	$75,095
Three Phase, Minimum Charge	2,107	2,107	2,060	bill	$165.00	$339,900	$195.00	$401,700
Distribution Energy Charge, per kWh	205,868,661	206,890,825	225,796,414	kWh	6.743 ¢	$15,225,452	7.906 ¢	$17,851,464
Reactive Power Charge, per kvar	183,283	183,283	200,031	kvar	65.00 ¢	$130,020	65.00 ¢	$130,020
Energy Charge - Schedule 200								
All kWh, per kWh	205,868,661	206,890,825	225,796,414	kWh	2.110 ¢	$4,764,304	2.312 ¢	$5,220,413
Subtotal	205,868,661	206,890,825	225,796,414	kWh		$26,716,221		$31,324,066
Renewable Adjustment Clause (202), per kWh	205,868,661	206,890,825	225,796,414	kWh	0.241 ¢	$544,169	0.000 ¢	$0
Subtotal						$27,260,390		$31,324,066
Schedule 201								
All kWh, per kWh	205,868,661	206,890,825	225,796,414	kWh	3.389 ¢	$7,652,240	3.389 ¢	$7,652,240
Summer On Peak Adder, per On-peak kWh	104,560	104,560	114,115	kWh	12.030 ¢	$13,728	12.030 ¢	$13,728
Summer Off Peak Adder, per Off-peak kWh	1,044,582	1,044,582	1,140,035	kWh	-2.696 ¢	($30,735)	-2.696 ¢	($30,735)
Total	205,868,661	206,890,825	225,796,414	kWh		$34,895,623		$38,959,299
							Change	$4,063,676
Schedule No. 41/741 - Irrigation								
Agricultural Pumping Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	0	0	0	kWh	0.649 ¢	$0	0.933 ¢	$0
System Usage Charge								
Sch 200 related, per kWh	0	0	0	kWh	0.052 ¢	$0	0.064 ¢	$0
T&A and Sch 201 related, per kWh	0	0	0	kWh	0.101 ¢	$0	0.112 ¢	$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	$550.00	$0	$650.00	$0
Three Phase Load Size > 300 kW, per customer	0	0	0	bill	$2,170.00	$0	$2,550.00	$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	$22.90	$0	$26.80	$0
Three Phase Load Size 51-300 kW, per kW	0	0	0	kW	$15.70	$0	$18.40	$0
Three Phase Load Size > 300 kW, per kW	0	0	0	kW	$9.70	$0	$11.30	$0
Single Phase, Minimum Charge	0	0	0	bill	$100.00	$0	$115.00	$0
Three Phase, Minimum Charge	0	0	0	bill	$165.00	$0	$190.00	$0
Distribution Energy Charge, per kWh	0	0	0	kWh	6.639 ¢	$0	7.784 ¢	$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	2.077 ¢	$0	2.276 ¢	$0
Subtotal	0	0	0	kWh		$0		$0
Renewable Adjustment Clause (202), per kWh	0	0	0	kWh	0.241 ¢	$0	0.000 ¢	$0
Subtotal						$0		$0
Schedule 201								
All kWh, per kWh	0	0	0	kWh	3.336 ¢	$0	3.336 ¢	$0
Summer On Peak Adder, per On-peak kWh	0	0	0	kWh	12.030 ¢	$0	12.030 ¢	$0
Summer Off Peak Adder, per Off-peak kWh	0	0	0	kWh	-2.696 ¢	$0	-2.696 ¢	$0
Total	0	0	0	kWh		$0		$0
							Change	$0

PACIFIC POWER
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Forecast 12 Months Ended December 31, 2027

Schedule	Actual 7/24-6/25 Units	Normalized 7/24-6/25 Units	Forecast 1/27 - 12/27 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	154,761	154,761	139,882	kW	$2.73	$381,878	$3.18	$444,825
credit per kW of on-peak demand (OATT)	0	0	0	kW	($2.73)	$0	($3.18)	$0
System Usage Charge								
Sch 200 related, per kWh	31,510,485	31,510,485	28,480,923	kWh	0.056 ¢	$15,949	0.074 ¢	$21,076
T&A and Sch 201 related, per kWh	31,510,485	31,510,485	28,480,923	kWh	0.108 ¢	$30,759	0.128 ¢	$36,456
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$1,130.00	$0	$1,130.00	$0
Facility Capacity > 4,000 kW, per month	24	24	24	bill	$3,120.00	$74,880	$3,120.00	$74,880
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.30	$0	$1.35	$0
Facility Capacity > 4,000 kW, per kW	210,947	210,947	190,666	kW	$0.50	$95,333	$0.55	$104,866
Demand Charge, per kW of on-peak demand	154,761	154,761	139,882	kW	$7.78	$1,088,282	$6.11	$854,679
Reactive Power Charge, per kvar	0	0	0	kvar	60.00 ¢	$0	60.00 ¢	$0
Reactive Hours, per kvarh	2,988,600	2,988,600	2,701,262	kvarh	0.080 ¢	$2,161	0.080 ¢	$2,161
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	210,947	210,947	190,666	kW	$0.27	$51,480	$0.27	$51,480
Supplemental Reserves, per kW of Facility Cap.	210,947	210,947	190,666	kW	$0.27	$51,480	$0.27	$51,480
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	154,761	154,761	139,882	kW	$1.37	$191,638	$1.42	$198,632
On-Peak, per on-peak kWh	13,182,087	13,182,087	11,914,701	kWh	1.790 ¢	$213,273	1.855 ¢	$221,018
Off-Peak, per off-peak kWh	18,328,398	18,328,398	16,566,222	kWh	1.790 ¢	$296,535	1.855 ¢	$307,303
Unscheduled Energy, per kWh	1,109,918	1,109,918	1,003,206	kWh		$70,253		$70,253
Subtotal	32,620,403	32,620,403	29,484,129	kWh		$2,563,901		$2,439,109
Renewable Adjustment Clause (202), per kWh	32,620,403	32,620,403	29,484,129	kWh	0.229 ¢	$67,519	0.000 ¢	$0
Subtotal						$2,631,420		$2,439,109
Schedule 201								
On-Peak, per on-peak kWh	13,182,087	13,182,087	11,914,701	kWh	4.021 ¢	$479,090	4.021 ¢	$479,090
Off-Peak, per off-peak kWh	18,328,398	18,328,398	16,566,222	kWh	2.854 ¢	$472,800	2.854 ¢	$472,800
Total	32,620,403	32,620,403	29,484,129	kWh		$3,583,310		$3,390,999
							Change	($192,311)
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	97,476	97,476	39,602	kW	$3.12	$123,558	$4.84	$191,674
credit per kW of on-peak demand (OATT)	0	0	0	kW	($3.12)	$0	($4.84)	$0
System Usage Charge								
Sch 200 related, per kWh	10,409,506	10,409,506	5,618,756	kWh	0.054 ¢	$3,034	0.066 ¢	$3,708
T&A and Sch 201 related, per kWh	10,409,506	10,409,506	5,618,756	kWh	0.105 ¢	$5,900	0.112 ¢	$6,293
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	24	24	24	bill	$1,750.00	$42,000	$1,790.00	$42,960
Facility Capacity > 4,000 kW, per month	24	24	24	bill	$4,480.00	$107,520	$4,590.00	$110,160
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	24,436	24,436	22,087	kW	$1.35	$29,817	$1.40	$30,922
Facility Capacity > 4,000 kW, per kW	214,896	214,896	103,245	kW	$1.15	$118,732	$1.20	$123,894
Demand Charge, per kW of on-peak demand	97,476	97,476	39,602	kW	$6.09	$241,176	$6.22	$246,324
Reactive Power Charge, per kvar	44,333	44,333	12,517	kvar	55.00 ¢	$6,884	55.00 ¢	$6,884
Reactive Hours, per kvarh	4,300,749	4,300,749	974,371	kvarh	0.080 ¢	$779	0.080 ¢	$779
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	239,332	239,332	125,332	kW	$0.27	$33,840	$0.27	$33,840
Supplemental Reserves, per kW of Facility Cap.	239,332	239,332	125,332	kW	$0.27	$33,840	$0.27	$33,840
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	97,476	97,476	39,602	kW	$1.38	$54,651	$1.51	$59,799
On-Peak, per on-peak kWh	3,880,569	3,880,569	2,079,364	kWh	1.707 ¢	$35,495	1.875 ¢	$38,988
Off-Peak, per off-peak kWh	6,528,937	6,528,937	3,539,392	kWh	1.707 ¢	$60,417	1.875 ¢	$66,364
Unscheduled Energy, per kWh	411,583	411,583	168,199	kWh		$7,722		$7,722
Subtotal	10,821,089	10,821,089	5,786,955	kWh		$905,365		$1,004,151
Renewable Adjustment Clause (202), per kWh	10,821,089	10,821,089	5,786,955	kWh	0.229 ¢	$13,252	0.000 ¢	$0
Subtotal						$918,617		$1,004,151
Schedule 201								
On-Peak, per on-peak kWh	3,880,569	3,880,569	2,079,364	kWh	3.822 ¢	$79,473	3.822 ¢	$79,473
Off-Peak, per off-peak kWh	6,528,937	6,528,937	3,539,392	kWh	2.659 ¢	$94,112	2.659 ¢	$94,112
Total	10,821,089	10,821,089	5,786,955	kWh		$1,092,202		$1,177,736
							Change	$85,534
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	$0.081	$0	$0.127	$0
Primary	0	0	0	kW	$0.106	$0	$0.124	$0
Transmission	0	0	0	kW	$0.122	$0	$0.189	$0
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.245	$0	$0.247	$0
Primary	0	0	0	kW	$0.303	$0	$0.238	$0
Transmission	0	0	0	kW	$0.237	$0	$0.242	$0

PACIFIC POWER
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Forecast 12 Months Ended December 31, 2027

Schedule	Actual 7/24-6/25 Units	Normalized 7/24-6/25 Units	Forecast 1/27 - 12/27 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	1,330,572	1,330,572	1,328,711	kW	$2.61	$3,467,936	$3.80	$5,049,102
System Usage Charge								
Sch 200 related, per kWh	547,280,994	547,280,994	547,364,139	kWh	0.060 ¢	$328,418	0.068 ¢	$372,208
T&A and Sch 201 related, per kWh	547,280,994	547,280,994	547,364,139	kWh	0.117 ¢	$640,416	0.119 ¢	$651,363
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	1,049	1,049	1,068	bill	$800.00	$854,400	$950.00	$1,014,600
Facility Capacity > 4,000 kW, per month	38	38	38	bill	$2,210.00	$83,980	$2,620.00	$99,560
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,420,183	1,420,183	1,421,965	kW	$2.55	$3,626,011	$4.05	$5,758,958
Facility Capacity > 4,000 kW, per kW	225,437	225,437	220,660	kW	$1.00	$220,660	$1.60	$353,056
Demand Charge, per kW of on-peak demand	1,330,572	1,330,572	1,328,711	kW	$6.28	$8,344,305	$6.34	$8,424,028
Reactive Power Charge, per kvar	227,934	227,934	216,770	kvar	65.00 ¢	$140,901	65.00 ¢	$140,901
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,330,572	1,330,572	1,328,711	kW	$1.30	$1,727,324	$1.42	$1,886,770
On-Peak, per on-peak kWh	208,792,250	208,792,250	209,756,919	kWh	1.780 ¢	$3,733,673	1.938 ¢	$4,065,089
Off-Peak, per off-peak kWh	338,488,744	338,488,744	337,607,220	kWh	1.780 ¢	$6,009,409	1.938 ¢	$6,542,828
Subtotal	547,280,994	547,280,994	547,364,139	kWh		$29,177,433		$34,358,463
Renewable Adjustment Clause (202), per kWh	547,280,994	547,280,994	547,364,139	kWh	0.229 ¢	$1,253,464	0.000 ¢	$0
Subtotal						$30,430,897		$34,358,463
Schedule 201								
On-Peak, per on-peak kWh	208,792,250	208,792,250	209,756,919	kWh	4.107 ¢	$8,614,717	4.107 ¢	$8,614,717
Off-Peak, per off-peak kWh	338,488,744	338,488,744	337,607,220	kWh	2.959 ¢	$9,989,798	2.959 ¢	$9,989,798
Total	547,280,994	547,280,994	547,364,139	kWh		$49,035,412		$52,962,978
							Change	$3,927,566
Schedule No. 48/748 - Composite								
Large General Service (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	3,152,369	3,152,369	6,166,843	kW	$3.27	$20,165,576	$3.72	$22,940,656
System Usage Charge								
Sch 200 related, per kWh	1,481,870,783	1,481,923,901	2,755,542,313	kWh	0.056 ¢	$1,543,103	0.074 ¢	$2,039,102
T&A and Sch 201 related, per kWh	1,481,870,783	1,481,923,901	2,755,542,313	kWh	0.108 ¢	$2,975,985	0.128 ¢	$3,527,094
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	699	699	712	bill	$1,130.00	$804,560	$1,130.00	$804,560
Facility Capacity > 4,000 kW, per month	349	349	459	bill	$3,120.00	$1,432,080	$3,120.00	$1,432,080
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,450,813	1,450,813	1,461,126	kW	$1.30	$1,899,464	$1.35	$1,972,520
Facility Capacity > 4,000 kW, per kW	2,322,792	2,322,792	5,898,469	kW	$0.50	$2,949,235	$0.55	$3,244,158
Demand Charge, per kW of on-peak demand	3,152,369	3,152,369	6,166,843	kW	$7.78	$47,978,039	$6.11	$37,679,411
Reactive Power Charge, per kvar	189,076	189,076	174,854	kvar	60.00 ¢	$104,912	60.00 ¢	$104,912
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	3,152,369	3,152,369	6,166,843	kW	$1.37	$8,448,575	$1.42	$8,756,917
On-Peak, per on-peak kWh	565,058,014	565,078,014	1,038,583,818	kWh	1.790 ¢	$18,590,651	1.855 ¢	$19,265,730
Off-Peak, per off-peak kWh	916,812,769	916,845,887	1,716,958,495	kWh	1.790 ¢	$30,733,557	1.855 ¢	$31,849,580
Subtotal	1,481,870,783	1,481,923,901	2,755,542,313	kWh		$137,625,737		$133,616,720
Renewable Adjustment Clause (202), per kWh	1,481,870,783	1,481,923,901	2,755,542,313	kWh	0.229 ¢	$6,310,192	0.000 ¢	$0
Subtotal						$143,935,929		$133,616,720
Schedule 201								
On-Peak, per on-peak kWh	565,058,014	565,078,014	1,038,583,818	kWh	4.021 ¢	$41,761,455	4.021 ¢	$41,761,455
Off-Peak, per off-peak kWh	916,812,769	916,845,887	1,716,958,495	kWh	2.854 ¢	$49,001,995	2.854 ¢	$49,001,995
Total	1,481,870,783	1,481,923,901	2,755,542,313	kWh		$234,699,379		$224,380,170
							Change	($10,319,209)
Schedule No. 48/748 - Composite								
Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	2,960,428	2,960,428	3,705,775	kW	$3.66	$13,563,136	$5.38	$19,937,069
System Usage Charge								
Sch 200 related, per kWh	2,025,514,000	2,025,514,000	2,540,644,753	kWh	0.054 ¢	$1,371,948	0.066 ¢	$1,676,826
T&A and Sch 201 related, per kWh	2,025,514,000	2,025,514,000	2,540,644,753	kWh	0.105 ¢	$2,667,677	0.112 ¢	$2,845,522
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	48	48	50	bill	$1,750.00	$87,500	$1,790.00	$89,500
Facility Capacity > 4,000 kW, per month	72	72	73	bill	$4,480.00	$327,040	$4,590.00	$335,070
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	54,551	54,551	60,277	kW	$1.35	$81,374	$1.40	$84,388
Facility Capacity > 4,000 kW, per kW	2,948,936	2,948,936	3,690,061	kW	$1.15	$4,243,570	$1.20	$4,428,073
Demand Charge, per kW of on-peak demand	2,960,428	2,960,428	3,705,775	kW	$6.09	$22,568,170	$6.22	$23,049,920
Reactive Power Charge, per kvar	9,515	9,515	9,979	kvar	55.00 ¢	$5,488	55.00 ¢	$5,488
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	2,960,428	2,960,428	3,705,775	kW	$1.38	$5,113,969	$1.51	$5,595,721
On-Peak, per on-peak kWh	760,605,000	760,605,000	954,059,019	kWh	1.707 ¢	$16,285,787	1.875 ¢	$17,888,606
Off-Peak, per off-peak kWh	1,264,909,000	1,264,909,000	1,586,585,734	kWh	1.707 ¢	$27,083,019	1.875 ¢	$29,748,482
Subtotal	2,025,514,000	2,025,514,000	2,540,644,753	kWh		$93,398,678		$105,684,665
Renewable Adjustment Clause (202), per kWh	2,025,514,000	2,025,514,000	2,540,644,753	kWh	0.229 ¢	$5,818,076	0.000 ¢	$0
Subtotal						$99,216,754		$105,684,665
Schedule 201								
On-Peak, per on-peak kWh	760,605,000	760,605,000	954,059,019	kWh	3.822 ¢	$36,464,135	3.822 ¢	$36,464,135
Off-Peak, per off-peak kWh	1,264,909,000	1,264,909,000	1,586,585,734	kWh	2.659 ¢	$42,187,315	2.659 ¢	$42,187,315
Total	2,025,514,000	2,025,514,000	2,540,644,753	kWh		$177,868,204		$184,336,115
							Change	$6,467,911

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Schedule	Actual 7/24-6/25 Units	Normalized 7/24-6/25 Units	Forecast 1/27 - 12/27 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					N/A		N/A	
System Usage Charge								
Sch 200 related, per kWh					N/A		N/A	
T&A and Sch 201 related, per kWh					N/A		N/A	
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$1,750.00	$0	$1,790.00	$0
Facility Capacity > 4,000 kW, per month	12	12	12	bill	$4,480.00	$53,760	$4,590.00	$55,080
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.35	$0	$1.40	$0
Facility Capacity > 4,000 kW, per kW	376,100	376,100	287,271	kW	$1.15	$330,362	$1.20	$344,725
Demand Charge, per kW of on-peak demand	330,169	330,169	252,188	kW	$6.09	$1,535,825	$6.22	$1,568,609
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					N/A		N/A	
On-Peak, per on-peak kWh					N/A		N/A	
Off-Peak, per off-peak kWh					N/A		N/A	
Subtotal						$1,919,947		$1,968,414
Renewable Adjustment Clause (202), per kWh					N/A		N/A	
Subtotal						$1,919,947		$1,968,414
Schedule 201								
On-Peak, per on-peak kWh					N/A		N/A	
Off-Peak, per off-peak kWh					N/A		N/A	
Total						$1,919,947		$1,968,414
Energy Delivered	217,977,000	217,977,000	165,687,755				Change	$48,467
Schedule No. 15 - Composite								
Outdoor Area Lighting Service								
No. of Customers	5,979	5,979	5,841					
Transmission & Ancillary Services Charge								
per kWh	7,915,298	7,915,298	7,817,140	kWh	0.043 ¢	$3,395	0.174 ¢	$13,634
System Usage Charge								
Sch 200 related, per kWh	7,915,298	7,915,298	7,817,140	kWh	0.016 ¢	$1,240	0.028 ¢	$2,209
T&A and Sch 201 related, per kWh	7,915,298	7,915,298	7,817,140	kWh	0.031 ¢	$2,426	0.034 ¢	$2,644
Distribution Charge								
Distribution Charge, per kWh	7,915,298	7,915,298	7,817,140	kWh	9.392 ¢	$734,216	9.369 ¢	$732,385
Energy Charge - Schedule 200								
per kWh	7,915,298	7,915,298	7,817,140	kWh	0.677 ¢	$52,885	0.763 ¢	$59,622
Subtotal	7,915,298	7,915,298	7,817,140	kWh		$794,162		$810,494
Renewable Adjustment Clause (202), per kWh	7,915,298	7,915,298	7,817,140	kWh	0.159 ¢	$12,429	0.000 ¢	$0
Subtotal						$806,591		$810,494
Schedule 201								
per kWh	7,915,298	7,915,298	7,817,140	kWh	1.099 ¢	$85,926	1.099 ¢	$85,926
Total	7,915,298	7,915,298	7,817,140	kWh		$892,517		$896,420
							Change	$3,903
Schedule No. 51/751								
Street Lighting Service, Company-Owned System								
No. of Customers	1,293	1,293	1,306					
Transmission & Ancillary Services Charge								
per kWh	20,620,102	20,620,102	20,174,804	kWh	0.066 ¢	$13,318	0.242 ¢	$48,837
System Usage Charge								
Sch 200 related, per kWh	20,620,102	20,620,102	20,174,804	kWh	0.030 ¢	$6,001	0.030 ¢	$6,001
T&A and Sch 201 related, per kWh	20,620,102	20,620,102	20,174,804	kWh	0.050 ¢	$10,132	0.050 ¢	$10,132
Distribution Charge								
Distribution Charge, per kWh	20,620,102	20,620,102	20,174,804	kWh	13.111 ¢	$2,645,119	13.088 ¢	$2,640,522
Energy Charge - Schedule 200								
per kWh	20,620,102	20,620,102	20,174,804	kWh	0.998 ¢	$201,327	1.059 ¢	$213,739
Subtotal	20,620,102	20,620,102	20,174,804	kWh		$2,875,897		$2,919,232
Renewable Adjustment Clause (202), per kWh	20,620,102	20,620,102	20,174,804	kWh	0.159 ¢	$32,078	0.000 ¢	$0
Subtotal						$2,907,975		$2,919,232
Schedule 201								
per kWh	20,620,102	20,620,102	20,174,804	kWh	1.472 ¢	$297,043	1.472 ¢	$297,043
Total	0	0	20,174,804	kWh		$3,205,018		$3,216,275
							Change	$11,257

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2025
Forecast 12 Months Ended December 31, 2027

Schedule	Actual 7/24-6/25 Units	Normalized 7/24-6/25 Units	Forecast 1/27 - 12/27 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 53/753								
Street Lighting Service, Consumer-Owned System								
No. of Customers	305	305	302					
Transmission & Ancillary Services Charge								
per kWh	7,982,652	7,982,652	8,104,668	kWh	0.021 ¢	$1,702	0.079 ¢	$6,403
System Usage Charge								
Sch 200 related, per kWh	7,982,652	7,982,652	8,104,668	kWh	0.008 ¢	$648	0.011 ¢	$892
T&A and Sch 201 related, per kWh	7,982,652	7,982,652	8,104,668	kWh	0.014 ¢	$1,135	0.017 ¢	$1,378
Distribution Charge								
Distribution Charge, per kWh	7,982,652	7,982,652	8,104,668	kWh	4.136 ¢	$335,232	4.207 ¢	$340,986
Energy Charge - Schedule 200								
per kWh	7,982,652	7,982,652	8,104,668	kWh	0.295 ¢	$23,909	0.341 ¢	$27,637
Subtotal	7,982,652	7,982,652	8,104,668	kWh		$362,625		$377,295
Renewable Adjustment Clause (202), per kWh	7,982,652	7,982,652	8,104,668	kWh	0.159 ¢	$12,886	0.000 ¢	$0
Subtotal						$375,511		$377,295
Schedule 201								
per kWh	7,982,652	7,982,652	8,104,668	kWh	0.984 ¢	$79,750	0.984 ¢	$79,750
Total	7,982,652	7,982,652	8,104,668	kWh		$455,261		$457,045
							Change	$1,783
Schedule No. 54/754								
Recreational Field Lighting								
Transmission & Ancillary Services Charge								
per kWh	1,367,299	1,367,299	1,364,686	kWh	0.026 ¢	$355	0.099 ¢	$1,351
System Usage Charge								
Sch 200 related, per kWh	1,367,299	1,367,299	1,364,686	kWh	0.010 ¢	$136	0.013 ¢	$177
T&A and Sch 201 related, per kWh	1,367,299	1,367,299	1,364,686	kWh	0.017 ¢	$232	0.021 ¢	$287
Distribution Charge								
Basic Charge, Single Phase, per month	744	744	738	bill	$6.00	$4,428	$6.00	$4,428
Basic Charge, Three Phase, per month	417	417	414	bill	$9.00	$3,726	$9.00	$3,726
Distribution Energy Charge, per kWh	1,367,299	1,367,299	1,364,686	kWh	4.589 ¢	$62,625	4.642 ¢	$63,349
Energy Charge - Schedule 200								
per kWh	1,367,299	1,367,299	1,364,686	kWh	0.371 ¢	$5,063	0.425 ¢	$5,800
Subtotal	1,367,299	1,367,299	1,364,686	kWh		$76,565		$79,118
Renewable Adjustment Clause (202), per kWh	1,367,299	1,367,299	1,364,686	kWh	0.159 ¢	$2,170	0.000 ¢	$0
Subtotal						$78,735		$79,118
Schedule 201								
per kWh	1,367,299	1,367,299	1,364,686	kWh	0.984 ¢	$13,429	0.984 ¢	$13,429
Total	1,367,299	1,367,299	1,364,686	kWh		$92,164		$92,547
							Change	$383
Subtotal Oregon	14,555,238,352	14,409,790,755	16,072,274,964			$1,786,000,529		$1,947,669,683
Employee Discount						($462,692)		($520,717)
TOTAL OREGON	**14,555,238,352**	**14,409,790,755**	**16,072,274,964**			**$1,785,537,837**		**$1,947,148,966**
Distribution Only Energy	217,977,000	217,977,000	165,687,755					
Total Energy Including Distribution Only	14,773,215,352	14,627,767,755	16,237,962,720					

Docket No. UE 470
Exhibit PAC/1005
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed Price Changes and Monthly Billing Comparisons

May 2026

Incremental General Rate Case after Interim Increase

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, 2027

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	Schedule 4 - Single Family	4	436,916	4,774,187	$707,197	$61,683	$768,879	$773,835	$55,524	$829,359	$66,638	9.4%	$60,480	7.9%	1
2	Schedule 4 - Multi-Family	4	120,768	805,836	$118,532	$10,411	$128,944	$128,597	$9,372	$137,969	$10,065	8.5%	$9,025	7.0%	2
3	**Total Residential**		557,684	5,580,023	$825,729	$72,094	$897,823	$902,432	$64,896	$967,328	$76,703	9.3%	$69,505	7.7%	3
	Commercial & Industrial														
4	Gen. Svc. < 31 kW	23	88,061	1,107,088	$169,628	$11,523	$181,151	$189,450	$5,733	$195,183	$19,822	11.7%	$14,032	7.7%	4
5	Gen. Svc. 31 - 200 kW	28/29	10,623	1,973,007	$201,589	$31,428	$233,017	$220,435	$25,823	$246,258	$18,846	9.3%	$13,241	5.7%	5
6	Gen. Svc. 201 - 999 kW	30	839	1,270,076	$120,859	$18,960	$139,819	$123,514	$19,649	$143,163	$2,655	2.2%	$3,344	2.4%	6
7	Large General Service >= 1,000 kW	48	200	5,843,551	$475,854	$47,352	$523,205	$461,679	$74,433	$536,112	($14,174)	-3.0%	$12,907	2.4%	7
8	Partial Req. Svc. >= 1,000 kW	47	6	35,271	$4,814	$288	$5,102	$4,569	$549	$5,117	($246)	-3.0%	$15	2.4%	8
9	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$1,982	$308	$2,291	$1,968	$323	$2,292	($14)	-0.7%	$1	0.0%	9
10	Agricultural Pumping Service	41	7,808	225,796	$35,787	($3,048)	$32,739	$38,959	($3,701)	$35,258	$3,172	8.9%	$2,519	7.7%	10
11	**Total Commercial & Industrial**		107,538	10,454,790	$1,010,514	$106,810	$1,117,324	$1,040,575	$122,808	$1,163,383	$30,061	3.0%	$46,059	4.1%	11
	Lighting														
12	Outdoor Area Lighting Service	15	5,841	7,817	$924	$223	$1,147	$896	$250	$1,147	($27)	-3.0%	($0)	0.0%	12
13	Street Lighting Service Comp. Owned	51	1,306	20,175	$3,322	$977	$4,299	$3,216	$1,083	$4,299	($106)	-3.2%	($0)	0.0%	13
14	Street Lighting Service Cust. Owned	53	302	8,105	$474	$228	$702	$457	$245	$702	($17)	-3.7%	$0	0.0%	14
15	Recreational Field Lighting	54	96	1,365	$96	$48	$144	$93	$52	$144	($4)	-3.7%	$0	0.0%	15
16	**Total Public Street Lighting**		7,545	37,461	$4,816	$1,476	$6,292	$4,662	$1,630	$6,292	($154)	-3.2%	($0)	0.0%	16
17	**Subtotal**		672,767	16,072,275	$1,841,059	$180,380	$2,021,440	$1,947,670	$189,334	$2,137,004	$106,610	5.8%	$115,564	5.7%	17
18	Emplolyee Discount		*978*	*13,169*	($459)	($43)	($502)	($521)	($38)	($559)	($62)		($57)		18
19	Paperless Credit				($1,991)		($1,991)	($1,991)		($1,991)	$0		$0		19
20	AGA Revenue				$9,715		$9,715	$9,715		$9,715	$0		$0		20
21	COOC Amortization				$44		$44	$44		$44	$0		$0		21
22	**Total**		672,767	16,072,275	$1,848,368	$180,338	$2,028,705	$1,954,916	$189,296	$2,144,212	$106,549	5.8%	$115,507	5.7%	22

[1] Excludes effects of the low income assistance charges (Sch. 91 and Sch. 92), BPA credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Trust of Oregon and Energy Efficiency Funding Charge (Sch. 292).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Total General Rate Case from Present Rates

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, 2027

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	Schedule 4 - Single Family	4	436,916	4,774,187	$686,255	$61,683	$747,937	$773,835	$55,524	$829,359	$87,580	12.8%	$81,422	10.9%	1
2	Schedule 4 - Multi-Family	4	120,768	805,836	$115,020	$10,411	$125,432	$128,597	$9,372	$137,969	$13,577	11.8%	$12,538	10.0%	2
3	**Total Residential**		557,684	5,580,023	$801,275	$72,094	$873,369	$902,432	$64,896	$967,328	$101,158	12.6%	$93,959	10.8%	3
	Commercial & Industrial														
4	Gen. Svc. < 31 kW	23	88,061	1,107,088	$164,694	$11,523	$176,217	$189,450	$5,733	$195,183	$24,756	15.0%	$18,966	10.8%	4
5	Gen. Svc. 31 - 200 kW	28/29	10,623	1,973,007	$195,242	$31,428	$226,670	$220,435	$25,823	$246,258	$25,193	12.9%	$19,588	8.6%	5
6	Gen. Svc. 201 - 999 kW	30	839	1,270,076	$117,051	$18,960	$136,011	$123,514	$19,649	$143,163	$6,464	5.5%	$7,153	5.3%	6
7	Large General Service >= 1,000 kW	48	200	5,843,551	$461,603	$47,352	$508,955	$461,679	$74,433	$536,112	$76	0.0%	$27,157	5.3%	7
8	Partial Req. Svc. >= 1,000 kW	47	6	35,271	$4,676	$288	$4,963	$4,569	$549	$5,117	($107)	0.0%	$154	5.3%	8
9	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$1,920	$308	$2,228	$1,968	$323	$2,292	$48	2.5%	$63	2.8%	9
10	Agricultural Pumping Service	41	7,808	225,796	$34,896	($3,048)	$31,847	$38,959	($3,701)	$35,258	$4,064	11.6%	$3,411	10.7%	10
11	**Total Commercial & Industrial**		107,538	10,454,790	$980,081	$106,810	$1,086,891	$1,040,575	$122,808	$1,163,383	$60,494	6.2%	$76,492	7.0%	11
	Lighting														
12	Outdoor Area Lighting Service	15	5,841	7,817	$893	$223	$1,116	$896	$250	$1,147	$4	0.4%	$31	2.8%	12
13	Street Lighting Service Comp. Owned	51	1,306	20,175	$3,205	$977	$4,182	$3,216	$1,083	$4,299	$11	0.4%	$117	2.8%	13
14	Street Lighting Service Cust. Owned	53	302	8,105	$455	$228	$683	$457	$245	$702	$2	0.4%	$19	2.8%	14
15	Recreational Field Lighting	54	96	1,365	$92	$48	$140	$93	$52	$144	$0	0.4%	$4	2.8%	15
16	**Total Public Street Lighting**		7,545	37,461	$4,645	$1,476	$6,121	$4,662	$1,630	$6,292	$17	0.4%	$171	2.8%	16
17	**Subtotal**		672,767	16,072,275	$1,786,001	$180,380	$1,966,381	$1,947,670	$189,334	$2,137,004	$161,669	9.1%	$170,623	8.7%	17
18	Emplolyee Discount		*978*	*13,169*	($463)	($43)	($505)	($521)	($38)	($559)	($58)		($54)		18
19	Paperless Credit				($1,991)		($1,991)	($1,991)		($1,991)	$0		$0		19
20	AGA Revenue				$9,715		$9,715	$9,715		$9,715	$0		$0		20
21	COOC Amortization				$44		$44	$44		$44	$0		$0		21
22	**Total**		672,767	16,072,275	$1,793,305	$180,338	$1,973,643	$1,954,916	$189,296	$2,144,212	$161,611	9.0%	$170,569	8.6%	22

[1] Excludes effects of the low income assistance charges (Sch. 91 and Sch. 92), BPA credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Trust of Oregon and Energy Efficiency Funding Charge (Sch. 292).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

PACIFIC POWER
STATE OF OREGON
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2027

Line No.	Description	Pre Sch No.	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)	Def Acct Adj 192 ($000)	RAC Defer. 203 ($000)	RAC Defer. 203 ($000)	Sol. Inctv. 204 ($000)	PCAM 206 ($000)	Comm. Sol 207 ($000)	System Benefits 291 ($000)	RMA 299 ($000)	RMA 299 ($000)	Total ($000)	Total ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
						PRE	PRO	PRE	PRO	PRE	PRO					PRE	PRO	PRE	PRO
	Residential																		
1	Schedule 4 - Single Family	4	$10,742	$0	$0	$8,737	$9,453	$12,938	$13,559	$239	$3,103	$1,337	$31,080	$573	$3,103	($7,066)	($17,426)	$61,683	$55,524
1	Schedule 4 - Multi-Family	4	$1,813	$0	$0	$1,475	$1,596	$2,184	$2,289	$40	$524	$226	$5,246	$97	$524	($1,193)	($2,941)	$10,411	$9,372
2	**Total Residential**		$12,555	$0	$0	$10,211	$11,048	$15,122	$15,847	$279	$3,627	$1,562	$36,326	$670	$3,627	($8,258)	($20,367)	$72,094	$64,896
	Commercial & Industrial																		
3	Gen. Svc. < 31 kW	23	$2,735	$0	$0	$2,236	$2,425	$2,989	$3,144	$55	$343	$288	$6,652	$133	$742	($4,307)	($10,728)	$11,523	$5,733
4	Gen. Svc. 31 - 200 kW	28/29	$2,249	$0	$0	$1,835	$1,973	$2,841	$3,019	$99	$612	$513	$11,718	$217	$1,026	$10,930	$4,497	$31,428	$25,823
5	Gen. Svc. 201 - 999 kW	30	$1,041	$0	$0	$851	$914	$1,486	$1,588	$64	$394	$330	$7,415	$140	$597	$7,036	$7,230	$18,960	$19,649
6	Large General Service >= 1,000 kW	48	$2,980	$0	$0	$2,454	$2,630	$5,435	$5,785	$292	$1,695	$1,402	$31,983	$643	$2,162	$0	$25,153	$47,352	$74,433
7	Partial Req. Svc. >= 1,000 kW	47	$18	$0	$0	$15	$16	$33	$35	$2	$10	$8	$195	$4	$13	$0	$249	$288	$549
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	$85	$0	$0	$70	$75	$154	$164	$0	$0	$0	$0	$0	$0	$0	$0	$308	$323
9	Agricultural Pumping Service	41	$680	$0	$0	$555	$596	$614	$646	$11	$68	$56	$1,294	$25	$138	($6,422)	($7,203)	($3,048)	($3,701)
10	**Total Commercial & Industrial**		$9,788	$0	$0	$8,016	$8,628	$13,552	$14,380	$523	$3,121	$2,598	$59,256	$1,161	$4,678	$7,238	$19,198	$106,810	$122,808
	Lighting																		
11	Outdoor Area Lighting Service	15	$24	$0	$0	$20	$21	$14	$15	$0	$1	$0	$18	$0	$4	$142	$167	$223	$250
12	Street Lighting Service Comp. Owned	51	$93	$0	$0	$76	$81	$55	$57	$0	$3	$2	$61	$1	$17	$673	$770	$977	$1,083
13	Street Lighting Service, Cust Owned	53	$11	$0	$0	$9	$10	$20	$21	$0	$0	$2	$16	$1	$3	$166	$181	$228	$245
14	Recreational Field Lighting	54	$2	$0	$0	$2	$2	$3	$4	$0	$0	$0	$3	$0	$1	$36	$40	$48	$52
15	**Total Public Street Lighting**		$131	$0	$0	$107	$113	$92	$96	$1	$4	$4	$98	$2	$25	$1,017	$1,157	$1,476	$1,630
16	**Subtotal**		$22,473	$0	$0	$18,334	$19,790	$28,766	$30,324	$802	$6,752	$4,165	$95,680	$1,833	$8,330	($3)	($12)	$180,380	$189,334
17	Employee Discount		($7)	$0	$0	($6)	($7)	($9)	($9)	($0)	($2)	($1)	($21)	($0)	($2)	$5	$12	($43)	($38)
18	**Total**		$22,466	$0	$0	$18,328	$19,783	$28,757	$30,314	$802	$6,750	$4,164	$95,658	$1,832	$8,328	$2	$0	$180,338	$189,296

PACIFIC POWER
STATE OF OREGON
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2027

Line No.	Description	Pre Sch No.	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	Def Acct Adj 192 ¢/kWh	RAC Defer. 203 ¢/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	System Benefits 291 ¢/kWh	RMA Sec. 299 ¢/kWh	RMA Pri. 299 ¢/kWh	RMA Trans. 299 ¢/kWh	RMA Sec. 299 ¢/kWh	RMA Pri. 299 ¢/kWh	RMA Trans. 299 ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6) PRE	(7) PRO	(8) PRE	(9) PRO	(9) PRE	(10) PRO	(11)	(12)	(13)	(14)	(15)	(16)	(17) PRE	(18) PRE	(19) PRE	(20) PRO	(21) PRO	(22) PRO
	Residential																						
1	Residential	4	0.225	0.000	0.000	0.183	0.198	0.271	0.284	0.005	0.065	0.028	0.651			0.012	0.065	(0.148)			(0.365)		
	Commercial & Industrial																						
2	Gen. Svc. < 31 kW	23	0.247	0.000	0.000	0.202	0.219	0.270	0.284	0.005	0.031	0.026	0.601	0.544		0.012	0.067	(0.389)	(0.389)		(0.969)	(0.969)	
3	Gen. Svc. 31 - 200 kW	28/29	0.114	0.000	0.000	0.093	0.100	0.144	0.153	0.005	0.031	0.026	0.594	0.582		0.011	0.052	0.554	0.554		0.225	0.554	
4	Gen. Svc. 201 - 999 kW	30	0.082	0.000	0.000	0.067	0.072	0.117	0.125	0.005	0.031	0.026	0.584	0.581		0.011	0.047	0.554	0.554		0.554	0.809	
5	Large General Service >= 1,000 kW	48	0.051	0.000	0.000	0.042	0.045	0.093	0.099	0.005	0.029	0.024	0.579	0.557	0.530	0.011	0.037	0.000	0.000	0.000	0.073	0.831	0.073
6	Partial Req. Svc. >= 1,000 kW	47	0.051	0.000	0.000	0.042	0.045	0.093	0.099	0.005	0.029	0.024	0.579	0.557	0.530	0.011	0.037	0.000	0.000	0.000	0.073	0.831	0.073
7	Dist. Only Lg Gen Svc >= 1,000 kW	848	0.051	0.000	0.000	0.042	0.045	0.093	0.099	0.000	0.000	0.000	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	0.301	0.000	0.000	0.246	0.264	0.272	0.286	0.005	0.030	0.025	0.573	0.526		0.011	0.061	(2.844)	(2.844)		(3.190)	(3.190)	
	Lighting																						
9	Outdoor Area Lighting Service	15	1.111	0.000	0.000	0.906	0.964	0.646	0.665	0.004	0.034	0.020	0.804			0.009	0.183	6.510			7.650		
10	Street Lighting Service HPS	51	1.048	0.000	0.000	0.855	0.907	0.620	0.639	0.005	0.031	0.020	0.685			0.009	0.190	7.573			8.665		
11	Street Lighting Service	53	0.136	0.000	0.000	0.111	0.118	0.241	0.260	0.002	0.006	0.020	0.202			0.009	0.043	2.044			2.230		
12	Recreational Field Lighting	54	0.170	0.000	0.000	0.138	0.147	0.255	0.274	0.003	0.008	0.020	0.202			0.009	0.055	2.671			2.900		

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Single Family
Total GRC, Interim, and Incremental GRC Change

kWh	Monthly Billing*			Total GRC Change		Interim Change		Incremental GRC Change	
	Present Price	Interim Price	Proposed Price	Dollars	Percent	Dollars	Percent	Dollars	Percent
100	$32.46	$33.26	$36.90	$4.44	13.68%	$0.80	2.46%	$3.64	10.94%
200	$46.64	$47.85	$52.48	$5.84	12.52%	$1.21	2.59%	$4.63	9.68%
300	$60.83	$62.43	$68.07	$7.24	11.90%	$1.60	2.63%	$5.64	9.03%
400	$75.02	$77.02	$83.65	$8.63	11.50%	$2.00	2.67%	$6.63	8.61%
500	$89.20	$91.60	$99.22	$10.02	11.23%	$2.40	2.69%	$7.62	8.32%
550	$96.30	$98.90	$107.02	$10.72	11.13%	$2.60	2.70%	$8.12	8.21%
600	$103.38	$106.19	$114.81	$11.43	11.06%	$2.81	2.72%	$8.62	8.12%
700	$117.57	$120.78	$130.39	$12.82	10.90%	$3.21	2.73%	$9.61	7.96%
800	$131.76	$135.37	$145.98	$14.22	10.79%	$3.61	2.74%	$10.61	7.84%
900	**$145.95**	**$149.96**	**$161.56**	**$15.61**	**10.70%**	**$4.01**	**2.75%**	**$11.60**	**7.74%**
950	$153.04	$157.26	$169.36	$16.32	10.66%	$4.22	2.76%	$12.10	7.69%
1,000	$160.13	$164.54	$177.14	$17.01	10.62%	$4.41	2.75%	$12.60	7.66%
1,100	$174.32	$179.13	$192.73	$18.41	10.56%	$4.81	2.76%	$13.60	7.59%
1,200	$188.51	$193.72	$208.31	$19.80	10.50%	$5.21	2.76%	$14.59	7.53%
1,300	$202.70	$208.31	$223.90	$21.20	10.46%	$5.61	2.77%	$15.59	7.48%
1,400	$216.88	$222.90	$239.48	$22.60	10.42%	$6.02	2.78%	$16.58	7.44%
1,500	$231.06	$237.48	$255.05	$23.99	10.38%	$6.42	2.78%	$17.57	7.40%
1,600	$245.25	$252.07	$270.64	$25.39	10.35%	$6.82	2.78%	$18.57	7.37%
2,000	$302.00	$310.42	$332.97	$30.97	10.25%	$8.42	2.79%	$22.55	7.26%
3,000	$457.17	$469.61	$502.11	$44.94	9.83%	$12.44	2.72%	$32.50	6.92%
4,000	$612.34	$628.79	$671.25	$58.91	9.62%	$16.45	2.69%	$42.46	6.75%
5,000	$767.52	$787.98	$840.39	$72.87	9.49%	$20.46	2.67%	$52.41	6.65%

* Net rate including Schedules 91, 92, 98, 290 and 292.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Multi-Family
Total GRC, Interim, and Incremental GRC Change

kWh	Monthly Billing*			Total GRC Change		Interim Change		Incremental GRC Change	
	Present Price	Interim Price	Proposed Price	Dollars	Percent	Dollars	Percent	Dollars	Percent
100	$26.37	$27.00	$28.78	$2.41	9.14%	$0.63	2.39%	$1.78	6.59%
200	$40.55	$41.58	$44.36	$3.81	9.40%	$1.03	2.54%	$2.78	6.69%
300	$54.74	$56.17	$59.95	$5.21	9.52%	$1.43	2.61%	$3.78	6.73%
400	$68.93	$70.76	$75.53	$6.60	9.57%	$1.83	2.65%	$4.77	6.74%
500	$83.11	$85.34	$91.10	$7.99	9.61%	$2.23	2.68%	$5.76	6.75%
550	**$90.21**	**$92.64**	**$98.90**	**$8.69**	**9.63%**	**$2.43**	**2.69%**	**$6.26**	**6.76%**
600	$97.29	$99.93	$106.69	$9.40	9.66%	$2.64	2.71%	$6.76	6.76%
700	$111.48	$114.52	$122.27	$10.79	9.68%	$3.04	2.73%	$7.75	6.77%
800	$125.67	$129.11	$137.86	$12.19	9.70%	$3.44	2.74%	$8.75	6.78%
900	$139.86	$143.70	$153.44	$13.58	9.71%	$3.84	2.75%	$9.74	6.78%
950	$146.95	$150.99	$161.24	$14.29	9.72%	$4.04	2.75%	$10.25	6.79%
1,000	$154.04	$158.28	$169.02	$14.98	9.72%	$4.24	2.75%	$10.74	6.79%
1,100	$168.23	$172.87	$184.61	$16.38	9.74%	$4.64	2.76%	$11.74	6.79%
1,200	$182.42	$187.46	$200.19	$17.77	9.74%	$5.04	2.76%	$12.73	6.79%
1,300	$196.61	$202.05	$215.78	$19.17	9.75%	$5.44	2.77%	$13.73	6.80%
1,400	$210.79	$216.64	$231.36	$20.57	9.76%	$5.85	2.78%	$14.72	6.79%
1,500	$224.97	$231.22	$246.93	$21.96	9.76%	$6.25	2.78%	$15.71	6.79%
1,600	$239.16	$245.81	$262.52	$23.36	9.77%	$6.65	2.78%	$16.71	6.80%
2,000	$295.91	$304.16	$324.85	$28.94	9.78%	$8.25	2.79%	$20.69	6.80%
3,000	$451.08	$463.35	$493.99	$42.91	9.51%	$12.27	2.72%	$30.64	6.61%
4,000	$606.25	$622.53	$663.13	$56.88	9.38%	$16.28	2.69%	$40.60	6.52%
5,000	$761.43	$781.72	$832.27	$70.84	9.30%	$20.29	2.66%	$50.55	6.47%

* Net rate including Schedules 91, 92, 98, 290 and 292.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage
Total GRC, Interim, and Incremental GRC Change

kW		Monthly Billing*						Total GRC Change Percent		Interim Change Percent		Incremental GRC Change Percent	
		Present Price		Interim Price		Proposed Price							
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$98	$108	$100	$111	$109	$123	11.21%	13.04%	2.56%	2.59%	8.43%	10.18%
	750	$136	$147	$140	$151	$149	$163	9.71%	11.16%	2.55%	2.57%	6.99%	8.38%
	1,000	$175	$185	$179	$190	$190	$204	8.87%	10.07%	2.54%	2.56%	6.17%	7.32%
	1,500	$251	$262	$258	$268	$271	$285	7.95%	8.83%	2.52%	2.53%	5.29%	6.14%
10	1,000	$175	$185	$179	$190	$190	$204	8.87%	10.07%	2.54%	2.56%	6.17%	7.32%
	2,000	$328	$338	$336	$347	$352	$366	7.46%	8.16%	2.52%	2.53%	4.82%	5.49%
	3,000	$481	$492	$493	$504	$514	$528	6.95%	7.44%	2.52%	2.52%	4.33%	4.80%
	4,000	$618	$629	$634	$644	$660	$674	6.78%	7.17%	2.50%	2.51%	4.18%	4.55%
20	4,000	$662	$672	$678	$689	$717	$730	8.33%	8.66%	2.52%	2.53%	5.66%	5.99%
	6,000	$936	$946	$959	$970	$1,008	$1,022	7.70%	7.95%	2.51%	2.51%	5.07%	5.31%
	8,000	$1,210	$1,221	$1,240	$1,251	$1,299	$1,313	7.36%	7.55%	2.50%	2.50%	4.74%	4.93%
	10,000	$1,485	$1,495	$1,522	$1,532	$1,591	$1,604	7.14%	7.30%	2.49%	2.49%	4.54%	4.69%
30	9,000	$1,434	$1,445	$1,470	$1,481	$1,558	$1,572	8.64%	8.79%	2.51%	2.51%	5.97%	6.12%
	12,000	$1,846	$1,856	$1,892	$1,903	$1,995	$2,009	8.09%	8.22%	2.50%	2.50%	5.45%	5.57%
	15,000	$2,257	$2,268	$2,313	$2,324	$2,432	$2,446	7.75%	7.85%	2.49%	2.50%	5.12%	5.22%
	18,000	$2,669	$2,679	$2,735	$2,746	$2,869	$2,883	7.51%	7.59%	2.49%	2.49%	4.89%	4.98%

* Net rate including Schedules 91, 92, 290 and 292.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage
Total GRC, Interim, and Incremental GRC Change

kW		Monthly Billing*						Total GRC Change Percent		Interim Change Percent		Incremental GRC Change Percent	
		Present Price		Interim Price		Proposed Price							
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$96	$107	$99	$110	$107	$121	11.26%	13.11%	2.56%	2.59%	8.49%	10.26%
	750	$134	$144	$137	$148	$147	$161	9.74%	11.21%	2.54%	2.56%	7.03%	8.44%
	1,000	$172	$182	$176	$187	$187	$200	8.89%	10.10%	2.54%	2.55%	6.19%	7.36%
	1,500	$247	$257	$253	$264	$266	$280	7.95%	8.85%	2.52%	2.53%	5.30%	6.16%
10	1,000	$172	$182	$176	$187	$187	$200	8.89%	10.10%	2.54%	2.55%	6.19%	7.36%
	2,000	$322	$332	$330	$341	$346	$359	7.45%	8.16%	2.51%	2.52%	4.82%	5.50%
	3,000	$472	$482	$484	$495	$505	$518	6.93%	7.43%	2.51%	2.51%	4.32%	4.80%
	4,000	$606	$617	$622	$632	$647	$661	6.75%	7.15%	2.50%	2.50%	4.15%	4.53%
20	4,000	$649	$660	$666	$676	$703	$717	8.32%	8.66%	2.52%	2.52%	5.66%	5.99%
	6,000	$918	$929	$941	$952	$989	$1,002	7.68%	7.93%	2.50%	2.50%	5.05%	5.29%
	8,000	$1,187	$1,198	$1,217	$1,228	$1,274	$1,288	7.33%	7.53%	2.49%	2.49%	4.72%	4.91%
	10,000	$1,456	$1,467	$1,493	$1,503	$1,560	$1,574	7.11%	7.27%	2.48%	2.49%	4.51%	4.67%
30	9,000	$1,408	$1,418	$1,443	$1,454	$1,529	$1,543	8.62%	8.78%	2.51%	2.51%	5.97%	6.12%
	12,000	$1,811	$1,822	$1,856	$1,867	$1,957	$1,971	8.07%	8.19%	2.50%	2.50%	5.44%	5.56%
	15,000	$2,215	$2,225	$2,270	$2,281	$2,386	$2,399	7.71%	7.82%	2.49%	2.49%	5.10%	5.20%
	18,000	$2,618	$2,629	$2,683	$2,694	$2,814	$2,828	7.47%	7.56%	2.48%	2.49%	4.87%	4.95%

* Net rate including Schedules 91, 92, 290 and 292.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
Total GRC, Interim, and Incremental GRC Change

kW Load Size	kWh	Monthly Billing* Present Price	Interim Price	Proposed Price	Total GRC Change Percent	Interim Change Percent	Incremental GRC Change Percent
15	3,000	$445	$456	$494	11.17%	2.55%	8.41%
	4,500	$591	$606	$638	7.89%	2.51%	5.25%
	7,500	$884	$906	$925	4.58%	2.48%	2.05%
31	6,200	$893	$916	$988	10.65%	2.54%	7.91%
	9,300	$1,196	$1,226	$1,285	7.43%	2.51%	4.80%
	15,500	$1,801	$1,846	$1,878	4.23%	2.47%	1.71%
40	8,000	$1,145	$1,175	$1,266	10.54%	2.54%	7.80%
	12,000	$1,536	$1,575	$1,649	7.33%	2.51%	4.70%
	20,000	$2,317	$2,375	$2,414	4.15%	2.47%	1.64%
60	12,000	$1,709	$1,752	$1,888	10.45%	2.53%	7.72%
	18,000	$2,295	$2,353	$2,461	7.25%	2.50%	4.63%
	30,000	$3,467	$3,553	$3,609	4.09%	2.47%	1.58%
80	16,000	$2,264	$2,321	$2,497	10.31%	2.53%	7.58%
	24,000	$3,045	$3,121	$3,262	7.13%	2.50%	4.51%
	40,000	$4,607	$4,721	$4,792	4.00%	2.47%	1.49%
100	20,000	$2,818	$2,889	$3,106	10.22%	2.53%	7.50%
	30,000	$3,795	$3,890	$4,062	7.05%	2.50%	4.44%
	50,000	$5,748	$5,890	$5,975	3.95%	2.47%	1.44%
200	40,000	$5,562	$5,703	$6,123	10.08%	2.53%	7.37%
	60,000	$7,515	$7,703	$8,035	6.92%	2.50%	4.31%
	100,000	$11,422	$11,704	$11,860	3.84%	2.47%	1.34%

* Net rate including Schedules 91, 92, 290 and 292.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
Total GRC, Interim, and Incremental GRC Change

kW Load Size	kWh	Monthly Billing* Present Price	Interim Price	Proposed Price	Total GRC Change Percent	Interim Change Percent	Incremental GRC Change Percent
15	3,000	$470	$482	$500	6.59%	2.56%	3.93%
	4,500	$606	$622	$637	5.12%	2.52%	2.54%
	7,500	$880	$902	$911	3.56%	2.48%	1.06%
31	6,200	$934	$957	$993	6.39%	2.55%	3.74%
	9,300	$1,216	$1,247	$1,276	4.92%	2.51%	2.35%
	15,500	$1,781	$1,825	$1,842	3.39%	2.47%	0.90%
40	8,000	$1,195	$1,225	$1,270	6.34%	2.55%	3.70%
	12,000	$1,559	$1,598	$1,635	4.88%	2.51%	2.31%
	20,000	$2,288	$2,345	$2,365	3.35%	2.47%	0.86%
60	12,000	$1,776	$1,821	$1,887	6.29%	2.54%	3.65%
	18,000	$2,322	$2,381	$2,435	4.83%	2.51%	2.26%
	30,000	$3,416	$3,501	$3,529	3.31%	2.47%	0.82%
80	16,000	$2,347	$2,407	$2,494	6.24%	2.54%	3.60%
	24,000	$3,077	$3,154	$3,224	4.78%	2.50%	2.22%
	40,000	$4,535	$4,647	$4,684	3.27%	2.47%	0.79%
100	20,000	$2,919	$2,993	$3,101	6.21%	2.54%	3.58%
	30,000	$3,831	$3,927	$4,013	4.75%	2.50%	2.19%
	50,000	$5,654	$5,793	$5,838	3.25%	2.47%	0.77%
200	40,000	$5,743	$5,889	$6,088	5.99%	2.54%	3.37%
	60,000	$7,566	$7,755	$7,912	4.57%	2.50%	2.02%
	100,000	$11,213	$11,489	$11,562	3.11%	2.46%	0.64%

* Net rate including Schedules 91, 92, 290 and 292.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
Total GRC, Interim, and Incremental GRC Change

kW Load Size	kWh	Monthly Billing* Present Price	Interim Price	Proposed Price	Total GRC Change Percent	Interim Change Percent	Incremental GRC Change Percent
100	20,000	$3,531	$3,623	$3,806	7.79%	2.60%	5.06%
	30,000	$4,285	$4,394	$4,547	6.14%	2.55%	3.49%
	50,000	$5,791	$5,936	$6,030	4.12%	2.50%	1.58%
200	40,000	$6,364	$6,529	$6,828	7.29%	2.58%	4.59%
	60,000	$7,871	$8,070	$8,310	5.58%	2.53%	2.98%
	100,000	$10,884	$11,153	$11,274	3.59%	2.48%	1.09%
300	60,000	$9,446	$9,689	$10,129	7.23%	2.58%	4.54%
	90,000	$11,706	$12,002	$12,352	5.52%	2.53%	2.92%
	150,000	$16,225	$16,627	$16,799	3.53%	2.47%	1.03%
400	80,000	$12,352	$12,670	$13,237	7.17%	2.57%	4.48%
	120,000	$15,365	$15,753	$16,201	5.44%	2.52%	2.85%
	200,000	$21,391	$21,919	$22,130	3.45%	2.47%	0.96%
500	100,000	$15,307	$15,700	$16,396	7.11%	2.57%	4.43%
	150,000	$19,073	$19,554	$20,101	5.39%	2.52%	2.80%
	250,000	$26,605	$27,262	$27,512	3.41%	2.47%	0.92%
600	120,000	$18,262	$18,731	$19,555	7.08%	2.57%	4.40%
	180,000	$22,781	$23,356	$24,001	5.36%	2.52%	2.76%
	300,000	$31,820	$32,605	$32,894	3.37%	2.47%	0.89%
800	160,000	$24,172	$24,792	$25,873	7.04%	2.57%	4.36%
	240,000	$30,197	$30,958	$31,801	5.31%	2.52%	2.72%
	400,000	$42,249	$43,291	$43,658	3.33%	2.47%	0.85%
1000	200,000	$30,081	$30,853	$32,190	7.01%	2.57%	4.33%
	300,000	$37,613	$38,561	$39,601	5.28%	2.52%	2.70%
	500,000	$52,678	$53,977	$54,422	3.31%	2.47%	0.82%

* Net rate including Schedules 91, 92, 290 and 292.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
Total GRC, Interim, and Incremental GRC Change

kW Load Size	kWh	Monthly Billing* Present Price	Interim Price	Proposed Price	Total GRC Change Percent	Interim Change Percent	Incremental GRC Change Percent
100	20,000	$3,377	$3,465	$3,486	3.22%	2.59%	0.61%
	30,000	$4,116	$4,221	$4,234	2.87%	2.54%	0.32%
	50,000	$5,594	$5,733	$5,732	2.46%	2.48%	-0.03%
200	40,000	$6,119	$6,276	$6,337	3.57%	2.57%	0.97%
	60,000	$7,597	$7,788	$7,834	3.13%	2.52%	0.59%
	100,000	$10,553	$10,813	$10,829	2.62%	2.47%	0.15%
300	60,000	$9,079	$9,312	$9,407	3.61%	2.57%	1.02%
	90,000	$11,296	$11,580	$11,652	3.16%	2.52%	0.62%
	150,000	$15,730	$16,117	$16,144	2.64%	2.46%	0.17%
400	80,000	$11,914	$12,219	$12,349	3.65%	2.56%	1.06%
	120,000	$14,870	$15,244	$15,344	3.19%	2.52%	0.66%
	200,000	$20,782	$21,293	$21,333	2.65%	2.46%	0.19%
500	100,000	$14,762	$15,140	$15,307	3.69%	2.56%	1.10%
	150,000	$18,457	$18,921	$19,050	3.21%	2.51%	0.68%
	250,000	$25,847	$26,483	$26,537	2.67%	2.46%	0.20%
600	120,000	$17,610	$18,061	$18,265	3.72%	2.56%	1.13%
	180,000	$22,044	$22,598	$22,757	3.23%	2.51%	0.70%
	300,000	$30,912	$31,672	$31,741	2.68%	2.46%	0.22%
800	160,000	$23,307	$23,903	$24,181	3.75%	2.56%	1.16%
	240,000	$29,219	$29,952	$30,170	3.25%	2.51%	0.73%
	400,000	$41,043	$42,051	$42,148	2.69%	2.46%	0.23%
1000	200,000	$29,003	$29,745	$30,096	3.77%	2.56%	1.18%
	300,000	$36,393	$37,307	$37,583	3.27%	2.51%	0.74%
	500,000	$51,174	$52,430	$52,556	2.70%	2.46%	0.24%

* Net rate including Schedules 91, 92, 290 and 292.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage
Total GRC, Interim, and Incremental GRC Change

		Present Price*		Interim Price*		Proposed Price*		Total GRC Change Percent		Interim Change Percent		Incremental GRC Change Percent	
kW Load Size	kWh	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge
Single Phase													
10	2,000	$249	$235	$255	$242	$272	$276	9.37%	17.24%	2.74%	2.80%	6.46%	14.05%
	3,000	$373	$235	$383	$242	$408	$276	9.37%	17.24%	2.73%	2.80%	6.46%	14.05%
	5,000	$622	$235	$639	$242	$680	$276	9.37%	17.24%	2.73%	2.80%	6.46%	14.05%
Three Phase													
20	4,000	$497	$471	$511	$484	$544	$552	9.37%	17.24%	2.73%	2.80%	6.46%	14.05%
	6,000	$746	$471	$766	$484	$816	$552	9.37%	17.24%	2.73%	2.80%	6.46%	14.05%
	10,000	$1,243	$471	$1,277	$484	$1,359	$552	9.37%	17.24%	2.73%	2.80%	6.46%	14.05%
100	20,000	$2,486	$2,182	$2,554	$2,243	$2,719	$2,558	9.37%	17.21%	2.73%	2.80%	6.46%	14.02%
	30,000	$3,729	$2,182	$3,831	$2,243	$4,078	$2,558	9.37%	17.21%	2.73%	2.80%	6.46%	14.02%
	50,000	$6,215	$2,182	$6,385	$2,243	$6,797	$2,558	9.37%	17.21%	2.73%	2.80%	6.46%	14.02%
300	60,000	$7,458	$5,410	$7,662	$5,561	$8,157	$6,334	9.37%	17.07%	2.73%	2.80%	6.46%	13.88%
	90,000	$11,188	$5,410	$11,493	$5,561	$12,235	$6,334	9.37%	17.07%	2.73%	2.80%	6.46%	13.88%
	150,000	$18,646	$5,410	$19,155	$5,561	$20,392	$6,334	9.37%	17.07%	2.73%	2.80%	6.46%	13.88%

* Net rate including Schedules 91, 92, 98, 290 and 292.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over
Total GRC, Interim, and Incremental GRC Change

kW Load Size	kWh	Monthly Billing*			Total GRC Change Percent	Interim Change Percent	Incremental GRC Change Percent
		Present Price	Interim Price	Proposed Price			
1,000	300,000	$36,589	$37,522	$39,791	8.75%	2.55%	6.05%
	500,000	$51,820	$53,118	$54,923	5.99%	2.50%	3.40%
	700,000	$67,050	$68,714	$69,969	4.35%	2.48%	1.83%
2,000	600,000	$72,366	$74,209	$78,291	8.19%	2.55%	5.50%
	1,000,000	$102,447	$105,021	$108,383	5.79%	2.51%	3.20%
	1,400,000	$132,357	$135,661	$138,475	4.62%	2.50%	2.07%
6,000	1,800,000	$205,982	$211,241	$218,718	6.18%	2.55%	3.54%
	3,000,000	$295,710	$303,160	$308,994	4.49%	2.52%	1.92%
	4,200,000	$385,438	$395,080	$399,270	3.59%	2.50%	1.06%
12,000	3,600,000	$408,721	$419,176	$434,276	6.25%	2.56%	3.60%
	6,000,000	$585,397	$600,235	$612,048	4.55%	2.53%	1.97%
	8,400,000	$758,180	$777,402	$785,928	3.66%	2.54%	1.10%

Notes:

On-Peak kWh	38.32%
Off-Peak kWh	61.68%

* Net rate including Schedules 91, 92, 290 and 292.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over
Total GRC, Interim, and Incremental GRC Change

kW Load Size	kWh	Monthly Billing*			Total GRC Change Percent	Interim Change Percent	Incremental GRC Change Percent
		Present Price	Interim Price	Proposed Price			
1,000	300,000	$37,523	$38,482	$38,633	2.96%	2.56%	0.39%
	500,000	$52,489	$53,806	$54,908	4.61%	2.51%	2.05%
	700,000	$67,456	$69,131	$71,096	5.40%	2.48%	2.84%
2,000	600,000	$73,898	$75,784	$75,791	2.56%	2.55%	0.01%
	1,000,000	$103,451	$106,053	$108,169	4.56%	2.51%	1.99%
	1,400,000	$132,833	$136,150	$140,546	5.81%	2.50%	3.23%
6,000	1,800,000	$215,065	$220,578	$221,227	2.87%	2.56%	0.29%
	3,000,000	$303,208	$310,869	$318,360	5.00%	2.53%	2.41%
	4,200,000	$391,352	$401,160	$415,492	6.17%	2.51%	3.57%
12,000	3,600,000	$425,963	$436,900	$438,788	3.01%	2.57%	0.43%
	6,000,000	$599,470	$614,702	$630,273	5.14%	2.54%	2.53%
	8,400,000	$769,085	$788,612	$817,865	6.34%	2.54%	3.71%

Notes:

On-Peak kWh	37.69%
Off-Peak kWh	62.31%

* Net rate including Schedules 91, 92, 290 and 292.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over
Total GRC, Interim, and Incremental GRC Change

kW Load Size	kWh	Monthly Billing*			Total GRC Change Percent	Interim Change Percent	Incremental GRC Change Percent
		Present Price	Interim Price	Proposed Price			
1,000	300,000	$35,940	$36,854	$38,236	6.39%	2.54%	3.75%
	500,000	$50,271	$51,526	$52,507	4.45%	2.50%	1.90%
	700,000	$64,602	$66,197	$66,692	3.23%	2.47%	0.75%
2,000	600,000	$70,103	$71,883	$74,327	6.02%	2.54%	3.40%
	1,000,000	$98,385	$100,845	$102,696	4.38%	2.50%	1.84%
	1,400,000	$126,495	$129,635	$131,066	3.61%	2.48%	1.10%
6,000	1,800,000	$206,827	$212,109	$219,971	6.35%	2.55%	3.71%
	3,000,000	$291,157	$298,480	$305,080	4.78%	2.52%	2.21%
	4,200,000	$375,486	$384,850	$390,189	3.92%	2.49%	1.39%
12,000	3,600,000	$408,107	$418,544	$434,782	6.54%	2.56%	3.88%
	6,000,000	$573,986	$588,505	$602,221	4.92%	2.53%	2.33%
	8,400,000	$735,973	$754,574	$765,767	4.05%	2.53%	1.48%

Notes:

On-Peak kWh	37.55%
Off-Peak kWh	62.45%

* Net rate including Schedules 91, 92, 290 and 292.

Docket No. UE 470
Exhibit PAC/1006
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Adjustment Schedule Calculations

May 2026

PACIFIC POWER
STATE OF OREGON
Calculation of Proposed Addition to Wildfire Mitigation Plan Cost Recovery Adjustment - Schedule 190

FORECAST 12 MONTHS ENDED DECEMBER 31, 2027

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	5,580,023	$469,514	57.6%	0.015	$837	0.198
2	**Total Residential**		5,580,023	$469,514			$837	
	Commercial & Industrial							
3	Gen. Svc. < 31 kW	23	1,107,088	$109,682	13.5%	0.017	$188	0.219
4	Gen. Svc. 31 - 200 kW	28/29	1,973,007	$80,405	9.9%	0.007	$138	0.100
5	Gen. Svc. 201 - 999 kW	30	1,270,076	$35,144	4.3%	0.005	$64	0.072
6	Large General Service >= 1,000 kW	48	5,843,551	$89,021		0.003	$175	0.045
7	Partial Req. Svc. >= 1,000 kW	47	35,271	$1,769	11.4%	0.003	$1	0.045
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	165,688	$1,968		0.003	$5	0.045
9	Agricultural Pumping Service	41	225,796	$23,559	2.9%	0.018	$41	0.264
10	**Total Commercial & Industrial**		10,620,478	$341,549			$612	
	Lighting							
11	Outdoor Area Lighting Service	15	2,189	$732	0.1%	0.058	$1	0.964
12	Street Lighting Service Comp. Owned	51	8,881	$2,641	0.3%	0.052	$5	0.907
13	Street Lighting Service Cust. Owned	53	8,105	$341	0.0%	0.007	$1	0.118
14	Recreational Field Lighting	54	1,365	$72	0.0%	0.009	$0	0.147
15	**Total Lighting**		20,539	$3,785			$7	
16	**Subtotal**		16,221,040	$814,848	100.0%		$1,455	
17	Emplolyee Discount			($265)			($0)	
18	**Total Sales with Employee Discount**			$814,583			$1,455	

* Includes Distribution Only consumer MWh and lighting tariff MWh

PACIFIC POWER
STATE OF OREGON
Calculation of Proposed Insurance Premium Deferred Accounting Adjustment - Schedule 192 Part B

FORECAST 12 MONTHS ENDED DECEMBER 31, 2027

Line No.	Description	Sch No.	MWh*	Proposed Base Revenues** ($000)	Equal Percentage Rate Spread	Proposed Schedule 192 Part B Base Rates (¢/kWh)	Proposed Schedule 192 Part B Base Revenues ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Residential						
1	Residential	4	5,580,023	$902,432	46.5%	0.013	$725
2	**Total Residential**		5,580,023	$902,432			$725
	Commercial & Industrial						
3	Gen. Svc. < 31 kW	23	1,107,088	$189,450	9.8%	0.014	$155
4	Gen. Svc. 31 - 200 kW	28/29	1,973,007	$220,435	11.4%	0.009	$178
5	Gen. Svc. 201 - 999 kW	30	1,270,076	$123,514	6.4%	0.008	$102
6	Large General Service >= 1,000 kW	48	5,843,551	$461,679		0.006	$351
7	Partial Req. Svc. >= 1,000 kW	47	35,271	$4,569	23.8%	0.006	$2
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	165,688	$1,968		0.006	$10
9	Agricultural Pumping Service	41	225,796	$38,959	2.0%	0.014	$32
10	**Total Commercial & Industrial**		10,620,478	$1,040,575			$828
	Lighting						
11	Outdoor Area Lighting Service	15	2,189	$896		0.019	$0
12	Street Lighting Service Comp. Owned	51	8,881	$3,216		0.019	$2
13	Street Lighting Service Cust. Owned	53	8,105	$457		0.019	$2
14	Recreational Field Lighting	54	1,365	$93		0.019	$0
15	**Total Lighting**		20,539	$4,662	0.2%	0.019	$4
16	**Subtotal**		16,221,040	$1,947,670	100.0%		$1,558
17	Emplolyee Discount			($521)			($0)
18	**Total Sales with Employee Discount**			$1,947,149			$1,557

* Includes Distribution Only consumer MWh and lighting tariff MWh

PACIFIC POWER
STATE OF OREGON
Calculation of Proposed Additions to Renewable Resource Deferral Adjustment - Schedule 203

FORECAST 12 MONTHS ENDED DECEMBER 31, 2027

Line No.	Description	Sch No.	MWh*	Proposed Sch 200 Generation Revenues ($000)	Generation Rate Spread	Proposed Schedule 203 Additions: Rock Creek I & II Rate (¢/kWh)	Rock Creek I & II Revenues ($000)	RAC Delayed Res Eff Date Rate (¢/kWh)	RAC Delayed Res Eff Date Revenues ($000)	Total Proposed 203 Rate (¢/kWh)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(8)
	Residential									
1	Residential	4	5,580,023	$143,239	37.865%	0.028	$1,562	0.032	$1,786	0.065
2	**Total Residential**		5,580,023	$143,239			$1,562		$1,786	
	Commercial & Industrial									
3	Gen. Svc. < 31 kW	23	1,107,088	$26,669	7.050%	0.026	$288			0.031
4	Gen. Svc. 31 - 200 kW	28/29	1,973,007	$46,788	12.368%	0.026	$513			0.031
5	Gen. Svc. 201 - 999 kW	30	1,270,076	$29,576	7.818%	0.026	$330			0.031
6	Large General Service >= 1,000 kW	48	5,843,551	$125,600	33.438%	0.024	$1,402			0.029
7	Partial Req. Svc. >= 1,000 kW	47	35,271	$892		0.024	$8			0.029
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	165,688	$0	0.000%	-	$0			-
9	Agricultural Pumping Service	41	225,796	$5,220	1.380%	0.025	$56			0.030
10	**Total Commercial & Industrial**		10,620,478	$234,745			$2,598			
	Lighting									
11	Outdoor Area Lighting Service	15	2,189	$60	0.016%	0.030	$1			0.034
12	Street Lighting Service Comp. Owned	51	8,881	$214	0.057%	0.026	$2			0.031
13	Street Lighting Service Cust. Owned	53	8,105	$28	0.007%	0.004	$0			0.006
14	Recreational Field Lighting	54	1,365	$6	0.002%	0.005	$0			0.008
15	**Total Lighting**		20,539	$307			$3			
16	**Subtotal**		16,221,040	$378,291	100.000%		$4,164		$1,786	
17	Emplolyee Discount			($85)			($1)		($1)	
18	**Total Sales with Employee Discount**			$378,206			$4,163		$1,785	

* Includes Distribution Only consumer MWh and lighting tariff MWh

Docket No. UE 470
Exhibit PAC/1007
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Adjustments Related to the Washington Service Area Transfer

May 2026

PACIFIC POWER
STATE OF OREGON
Calculation of Proposed Property Sales Balancing Account Adj. - Schedule 96

FORECAST 12 MONTHS ENDED DECEMBER 31, 2027

Line No.	Description	Sch No.	MWh*	Proposed Schedule 96 Rates (¢/kWh)	Proposed Schedule 96 Revenues ($000)
	(1)	(2)	(3)	(4)	(5)
	Residential				
1	Residential	4	5,580,023	(0.088)	($4,910)
2	**Total Residential**		5,580,023		($4,910)
	Commercial & Industrial				
3	Gen. Svc. < 31 kW	23	1,107,088	(0.088)	($974)
4	Gen. Svc. 31 - 200 kW	28/29	1,973,007	(0.088)	($1,736)
5	Gen. Svc. 201 - 999 kW	30	1,270,076	(0.088)	($1,118)
6	Large General Service >= 1,000 kW	48	5,843,551	(0.088)	($5,142)
7	Partial Req. Svc. >= 1,000 kW	47	35,271	(0.088)	($31)
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	165,688	(0.088)	($146)
9	Agricultural Pumping Service	41	225,796	(0.088)	($199)
10	**Total Commercial & Industrial**		10,620,478		($9,346)
	Lighting				
11	Outdoor Area Lighting Service	15	2,189	(0.088)	($2)
12	Street Lighting Service Comp. Owned	51	8,881	(0.088)	($8)
13	Street Lighting Service Cust. Owned	53	8,105	(0.088)	($7)
14	Recreational Field Lighting	54	1,365	(0.088)	($1)
15	**Total Lighting**		20,539		($18)
16	**Subtotal**		16,221,040		($14,275)
17	Emplolyee Discount				$3
18	**Total Sales with Employee Discount**				($14,272)

* Includes Distribution Only consumer MWh and lighting tariff MWh

PACIFIC POWER
STATE OF OREGON
Calculation of Proposed Washington Service Area Transfer Adjustment - Schedule 81

FORECAST 12 MONTHS ENDED DECEMBER 31, 2027

Line No.	Description	Sch No.	MWh*	Proposed Distribution Revenues ($000)	Distribution Rate Spread	Proposed Schedule 81 Rate (¢/kWh)	Proposed Schedule 81 Revenues ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Residential						
1	Residential	4	5,580,023	$469,514	57.6%	0.179	$9,988
2	**Total Residential**		5,580,023	$469,514			$9,988
	Commercial & Industrial						
3	Gen. Svc. < 31 kW	23	1,107,088	$109,682	13.5%	0.210	$2,325
4	Gen. Svc. 31 - 200 kW	28/29	1,973,007	$80,405	9.9%	0.087	$1,717
5	Gen. Svc. 201 - 999 kW	30	1,270,076	$35,144	4.3%	0.059	$749
6	Large General Service >= 1,000 kW	48	5,843,551	$89,021		0.033	$1,928
7	Partial Req. Svc. >= 1,000 kW	47	35,271	$1,769	11.4%	0.033	$12
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	165,688	$1,968		0.033	$55
9	Agricultural Pumping Service	41	225,796	$23,559	2.9%	0.222	$501
10	**Total Commercial & Industrial**		10,620,478	$341,549			$7,287
	Lighting						
11	Outdoor Area Lighting Service	15	2,189	$732	0.1%	0.711	$16
12	Street Lighting Service Comp. Owned	51	8,881	$2,641	0.3%	0.631	$56
13	Street Lighting Service Cust. Owned	53	8,105	$341	0.0%	0.089	$7
14	Recreational Field Lighting	54	1,365	$72	0.0%	0.111	$2
15	**Total Lighting**		20,539	$3,785			$80
16	**Subtotal**		16,221,040	$814,848	100.0%		$17,355
17	Emplolyee Discount			($265)			($6)
18	**Total Sales with Employee Discount**			$814,583			$17,349

* Includes Distribution Only consumer MWh and lighting tariff MWh

Washington Service Area Transfer

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, 2027

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	Schedule 4 - Single Family	4	436,916	4,774,187	$773,835	$55,524	$829,359	$782,381	$51,323	$833,703	$8,546	1.1%	$4,345	0.5%	1
2	Schedule 4 - Multi-Family	4	120,768	805,836	$128,597	$9,372	$137,969	$130,040	$8,663	$138,702	$1,442	1.1%	$733	0.5%	2
3	**Total Residential**		557,684	5,580,023	$902,432	$64,896	$967,328	$912,421	$59,985	$972,406	$9,988	1.1%	$5,078	0.5%	3
	Commercial & Industrial														
4	Gen. Svc. < 31 kW	23	88,061	1,107,088	$189,450	$5,733	$195,183	$191,775	$4,759	$196,534	$2,325	1.2%	$1,351	0.7%	4
5	Gen. Svc. 31 - 200 kW	28/29	10,623	1,973,007	$220,435	$25,823	$246,258	$222,151	$24,086	$246,238	$1,717	0.8%	($20)	0.0%	5
6	Gen. Svc. 201 - 999 kW	30	839	1,270,076	$123,514	$19,649	$143,163	$124,264	$18,531	$142,795	$749	0.6%	($368)	-0.3%	6
7	Large General Service >= 1,000 kW	48	200	5,843,551	$461,679	$74,433	$536,112	$463,608	$69,290	$532,898	$1,928	0.4%	($3,214)	-0.6%	7
8	Partial Req. Svc. >= 1,000 kW	47	6	35,271	$4,569	$549	$5,117	$4,580	$517	$5,098	$12	0.4%	($19)	-0.6%	8
9	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$1,968	$323	$2,292	$2,023	$177	$2,200	$55	2.8%	($91)	-4.0%	9
10	Agricultural Pumping Service	41	7,808	225,796	$38,959	($3,701)	$35,258	$39,461	($3,900)	$35,561	$501	1.3%	$303	0.9%	10
11	**Total Commercial & Industrial**		107,538	10,454,790	$1,040,575	$122,808	$1,163,383	$1,047,862	$113,462	$1,161,324	$7,287	0.7%	($2,059)	-0.2%	11
	Lighting														
12	Outdoor Area Lighting Service	15	5,841	7,817	$896	$250	$1,147	$912	$248	$1,160	$16	1.7%	$14	1.2%	12
13	Street Lighting Service Comp. Owned	51	1,306	20,175	$3,216	$1,083	$4,299	$3,272	$1,075	$4,347	$56	1.7%	$48	1.1%	13
14	Street Lighting Service Cust. Owned	53	302	8,105	$457	$245	$702	$464	$238	$702	$7	1.6%	$0	0.0%	14
15	Recreational Field Lighting	54	96	1,365	$93	$52	$144	$94	$50	$145	$2	1.6%	$0	0.2%	15
16	**Total Public Street Lighting**		7,545	37,461	$4,662	$1,630	$6,292	$4,743	$1,612	$6,355	$80	1.7%	$62	1.0%	16
17	**Subtotal**		672,767	16,072,275	$1,947,670	$189,334	$2,137,004	$1,965,025	$175,059	$2,140,084	$17,355	0.9%	$3,081	0.1%	17
18	Emplolyee Discount		*978*	*13,169*	($521)	($38)	($559)	($527)	($35)	($562)	($6)		($3)		18
19	Paperless Credit				($1,991)		($1,991)	($1,991)		($1,991)	$0		$0		19
20	AGA Revenue				$9,715		$9,715	$9,715		$9,715	$0		$0		20
21	COOC Amortization				$44		$44	$44		$44	$0		$0		21
22	**Total**		672,767	16,072,275	$1,954,916	$189,296	$2,144,212	$1,972,266	$175,024	$2,147,290	$17,349	0.9%	$3,078	0.1%	22

[1] Excludes effects of the low income assistance charges (Sch. 91 and Sch. 92), BPA credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Trust of Oregon and Energy Efficiency Funding Charge (Sch. 292).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Docket No. UE 470
Exhibit PAC/1008
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Calculation of Proposed Schedule 300 Facilities Charges

May 2026

PacifiCorp
State of Oregon
Schedule 300 Use of Facilities Charges
December 31, 2024 Basis, Based on Imbedded Rate of Return

Line		Distribution	Transmission
	Company Provides Initial Capital Investment (allowance) - Annual %		
1	Return on Capital	4.33%	4.76%
2	Recovery of Capital	2.67%	1.82%
3	State and Federal Income Taxes	0.92%	1.01%
4	Local Property Taxes	0.76%	0.83%
5	Operation & Maintenance	6.53%	0.86%
6	Administrative & General	1.81%	1.81%
7	Other Taxes	0.80%	0.11%
8	Customer Accounts & Services	1.03%	N/A
9	TOTAL (lines 1-8)	18.85%	11.20%
10	*Monthly %*	1.57%	0.93%
11	Monthly Proposed (rounded)	**1.57%**	**0.93%**
	Customer Provides Initial Capital Investment (customer advance) - Annual %		
12	Subtotal Lines 4 - 8	10.93%	3.61%
13	Capital Replacement Annuity	0.78%	0.44%
14	TOTAL (lines 12-13)	11.71%	4.05%
15	Monthly %	0.98%	0.34%
16	TOTAL (lines 4, 5, 7 & 13)	8.87%	2.24%
17	*Monthly %*	0.74%	0.19%
18	Monthly Proposed (rounded)	**0.74%**	**0.19%**

Docket No. UE 470
Exhibit PAC/1009
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Cumulative Economic Impact Analysis

May 2026

Pacific Power
State of Oregon
General Rate Case Cumulative Economic Impact Analysis

Background

Pursuant to Oregon Public Utility Commission (Commission) Order No. 26-078 and OAR 860-022-0500, PacifiCorp d/b/a Pacific Power is required to include a cumulative economic impact analysis for any proposed rate adjustments when filing a proposed rate adjustment that will result in an increase in residential rate or schedule of rates and where the utility's return on equity is subject to review and modification. This requirement applies to PacifiCorp's filing in docket UE 470.

PacifiCorp's economic impact analysis must include, at a minimum:

- For each classification of service of the electric or natural gas company affected by the proposed rate or schedule of rates and, if applicable, distinguished by ratepayers who reside in single-family housing and ratepayers who reside in multifamily housing:
    - Ratepayers' average monthly utility bill for the 18 months ending on the date before the date the proposed rate or schedule of rates is to take effect;
    - The approximate range of utility bills from November 1 to March 31 for the prior two years for residential ratepayers who use the utility service for space heating; and
    - The estimated dollar amount and percentage increase in ratepayers' utility bills.
- The average cost of living and cost of fuel and utilities for the region, state and, where available, service territory of the electric or natural gas company, as determined by the commission using the Consumer Price Index for All Urban Consumers, West Region (All Items), as most recently published by the Bureau of Labor Statistics of the United States Department of Labor, and any other macroeconomic data as determined by the commission.
- The electric or natural gas company's data on residential service disconnection for nonpayment, including:
    - The number of ratepayers the electric or natural gas company disconnected for nonpayment in the previous 12 months;

- The number of ratepayers receiving energy assistance, including any government assistance, utility bill discount or utility arrearage program, that the electric or natural gas company disconnected for nonpayment in the previous 12 months.
- The number of ratepayers who have a medical certificate filed with the electric or natural gas company; and
- Data related to customers who are enrolled in the electric or natural gas company's energy assistance programs, including disconnection moratorium programs.

- The electric or natural gas company's data on overdue balances, as determined by the commission, such as:
  - The number of ratepayers who have an overdue balance;
  - The average amount of the overdue balances; or
  - The total amount of overdue balances owed to the electric or natural gas company.
- Data on the cost of energy for commercial and industrial customers relative to the cost of energy for commercial and industrial customers in other states in the region together with historical trends.
- Any other relevant data, as determined by the commission, such as indicators of financial hardship, residential customer energy burden or affordability of utility bills.[1]

A. Bill Impact Analysis

For each classification of service of the electric or natural gas company affected by the proposed rate or schedule of rates and, if applicable, distinguished by ratepayers who reside in single-family housing and ratepayers who reside in multifamily housing:

a. Please see Appendix A to this analysis for residential ratepayers' average monthly utility bills for the 18 months ending on the date before the date the proposed rate or schedule of rates is to take effect.

[1] OAR 860-022-0500.

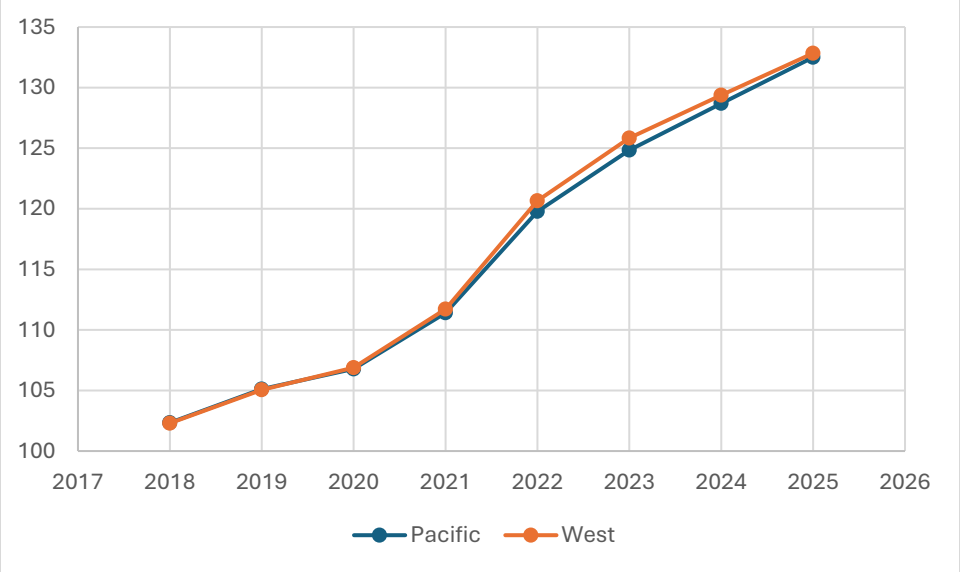
b. Please see Appendix B to this analysis for the approximate range of utility bills from November 1 to March 31 for the prior three years for residential ratepayers who use the utility service for space heating. Of note, March 2026 data reflects a partial month as the full month of data was not available at the time of preparation.

c. The estimated dollar amount and percentage increase in ratepayers' utility bills are provided as rate design exhibits within PacifiCorp's general rate case filing. Please refer to Exhibit PAC/1005 accompanying the Direct Testimony of Judith M. Ridenour in this proceeding.

B. Cost of Living Analysis

Figure 1 below provides the Consumer Price Index for All Urban Consumers, for the Pacific and West Region (All Items). Of note, the same data specific to the state of Oregon and PacifiCorp's service territory is not available from the U.S. Bureau of Labor Statistics.

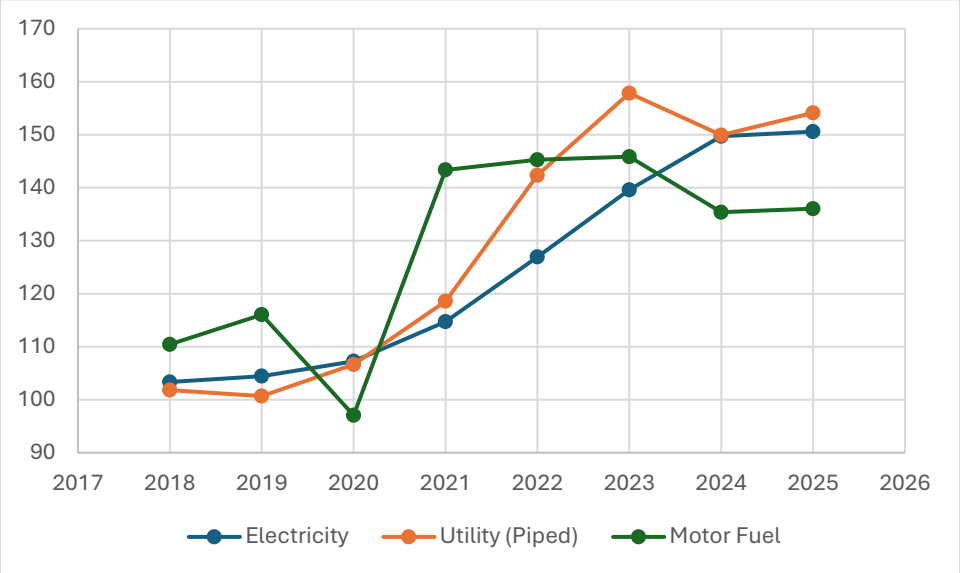
Figure 1: Consumer Price Index for All Urban Consumers, All Items



Source: U.S. Bureau of Labor Statistics, Consumer Price Index for All Urban Consumers, Series ID CUUR0490SA0 and CUUR0400SA0. Base Period December 2017.

Figure 2 below provides the Consumer Price Index for All Urban Consumers, in the West Region for Electricity, Utility Piped Gas and Motor Fuel.

Figure 2: Consumer Price Index for Select Energy Related Items, in West Urban



Source: U.S. Bureau of Labor Statistics, Consumer Price Index for All Urban Consumers, Series ID CUUS0400SEHF01, CUUS0400SEHF02 and CUUS0400SETB. Base Period December 2017.

C. Disconnection Analysis

Table A below provides the number of residential customers disconnected for nonpayment over the April 2025 to March 2026 timeframe, which is the most recently available twelve months of data at the time of preparation of this analysis. Additionally, Table A provides the number of disconnections for residential customers that receive assistance through the Oregon Energy Assistance Program (OEAP) or Low Income Energy Assistance Program (LIHEAP), have filed a medical certificate with the company and those that participate in the company's Low-income Discount Program (LID).

Table A: Residential Disconnection Data

Month	Total Residential Accounts	Total LID Customers	Total Disconnects (Number)	Total Disconnects (Percent of total Residential)	LID Disconnects (Number)	LID Disconnects (Percent of LID customers)	Energy Assistance Disconnects (Number)*	Energy Assistance Disconnects (Percent of total Residential)	Medical Certificate Disconnects
Apr-25	526,185	70,060	1,554	0.3%	358	0.51%	1	0.00%	0
May-25	526,977	71,093	3,916	0.7%	2,281	3.21%	44	0.01%	19
Jun-25	527,535	71,798	3,190	0.6%	2,055	2.86%	33	0.01%	18
Jul-25	527,778	71,194	2,631	0.5%	995	1.40%	23	0.00%	14
Aug-25	528,166	68,294	1,882	0.4%	708	1.04%	18	0.00%	7
Sep-25	528,315	66,673	2,837	0.5%	1,016	1.52%	29	0.01%	31
Oct-25	528,309	68,186	2,935	0.6%	1,284	1.88%	24	0.00%	22
Nov-25	527,661	57,384	1,449	0.3%	483	0.84%	7	0.00%	2
Dec-25	527,696	69,112	691	0.1%	2	0.00%	1	0.00%	0
Jan-26	528,008	70,035	572	0.1%	1	0.00%	1	0.00%	0
Feb-26	528,468	69,505	497	0.1%	0	0.00%	0	0.00%	0
Mar-26	529,682	74,267	1,165	0.2%	1	0.00%	0	0.00%	6

*Includes customers receiving OEAP or LIHEAP assistance.

Arrearage Analysis

Table B below provides the number of residential customers with arrears over the April 2025 to March 2026 timeframe, which is the most recently available twelve months of data at the time of preparation of this analysis. Additionally, Table B provides the average amount of overdue balances and the total amount of overdue balances owed to the company.

Table B: Residential Arrearage Data

Month	Total Residential Accounts in Arrears	Total Arrears Balance	Average Arrears Balance	LID Accounts in Arrears	LID Total Arrears Balance	LID Average Arrears Balance
Apr-25	111,031	$39,061,358	$352	30,020	$13,380,562	$446
May-25	114,836	$37,976,955	$331	30,366	$12,124,427	$399
Jun-25	105,106	$32,345,584	$308	28,742	$10,160,273	$353
Jul-25	109,233	$30,297,203	$277	27,702	$9,006,348	$325
Aug-25	110,018	$29,846,409	$271	26,124	$8,101,107	$310
Sep-25	108,453	$28,529,091	$263	24,694	$7,226,526	$293
Oct-25	107,486	$27,467,268	$256	25,352	$7,065,236	$279
Nov-25	103,333	$25,218,794	$244	20,638	$5,674,266	$275
Dec-25	105,964	$26,651,429	$252	27,214	$8,482,249	$312
Jan-26	98,521	$26,608,291	$270	27,065	$9,479,924	$350
Feb-26	98,155	$28,767,217	$293	26,765	$10,539,662	$394
Mar-26	101,807	$30,184,191	$296	28,640	$11,065,640	$386

D. Commercial/Industrial Cost Analysis

Tables C and D below provide the cost of energy for commercial and industrial customers relative to the cost of energy for commercial and industrial customers in other states in the region together with historical trends.

Table C: Commercial Average Rates for Investor-Owned Utilities ($/kWh)

Year	Washington	California	Oregon	PacifiCorp Oregon
2022	0.1077	0.1695	0.0933	0.0827
2023	0.1108	0.2162	0.0994	0.0855
2024	0.1258	0.2470	0.1143	0.1004
2025	0.1531	0.2441	0.1258	0.1103

Source: Edison Electric Institute (EEI), Typical Bills and Average Rates Report, Summer editions. Average rates in $/kWh 12 months ending June 30 of listed year.

Table D: Industrial Average Rates for Investor-Owned Utilities ($/kWh)

Year	Washington	California	Oregon	PacifiCorp Oregon
2022	0.0874	0.1025	0.0689	0.0730
2023	0.0958	0.1312	0.0725	0.0779
2024	0.1045	0.1819	0.0840	0.0940
2025	0.1191	0.1801	0.0930	0.1100

Source: Edison Electric Institute (EEI), Typical Bills and Average Rates Report, Summer editions. Average rates in $/kWh 12 months ending June 30 of listed year.

APPENDIX A

Pacific Power
Average Residential Ratepayer Estimated Monthly Bill
18 Months Prior to Expected Effective Date of Rate Change
Delivery Service Schedule 4 + Cost-Based Supply Service

	Single Family		Multi-Family	
	kWh	Monthly Billing	kWh	Monthly Billing
Jan-26	1,203	$189.47	734	$116.35
Feb-26	1,015	$162.47	620	$99.98
Mar-26	969	$155.51	592	$95.74
Apr-26	807	$136.38	493	$84.33
May-26	739	$123.10	451	$76.16
Jun-26 [1]	762	$129.81	465	$80.23
Jul-26	947	$156.80	578	$96.72
Aug-26	894	$149.06	546	$92.04
Sep-26	726	$124.56	444	$77.17
Oct-26	752	$128.35	459	$79.36
Nov-26	978	$161.31	597	$99.48
Dec-26	1,221	$196.76	745	$121.07
Jan-27	1,193	$192.68	728	$118.59
Feb-27	1,006	$165.40	614	$101.97
Mar-27	958	$158.40	585	$97.73
Apr-27 [2]	798	$129.79	487	$80.22
May-27	731	$120.46	446	$74.51
Jun-27	756	$123.94	462	$76.74

Net bill including all tariff adjustments. Includes expected rate changes for adjustments completing amortization. Does not include other filed rate changes pending review and approval (TAM) or other rate changes which may be filed during the period.

[1] Interim Rate Adjustment effective June 2026

[2] Cancel 2021, 2023, 2024 PCAM amortizations effective April 2027

APPENDIX B

PacifiCorp
State of Oregon
Range of Winter Month Utility Bills for Customers with Electric Space Heating

Billing and Usage for Oregon Residential Customers with Electric Heat November 2023 to March 2024

Accounting Period	202311			202312		
Dwelling Unit Description	Customers	Sum of Total kWh	Sum of Billed Amount	Customers	Sum of Total kWh	Sum of Billed Amount
Multi-Family	85,243	49,605,821	$6,521,494.58	85,328	68,717,070	$8,777,727.74
Single Family	186,623	210,967,774	$27,246,946.86	186,752	280,284,000	$35,730,493.78
Grand Total	271,866	260,573,595	$33,768,441.44	272,080	349,001,070	$44,508,221.52
		Monthly kWh	Monthly Bill		Monthly kWh	Monthly Bill
	Multi-Fam Avg Bill	582	$ 76.50	Multi-Fam Avg Bill	805	$ 102.87
	Single Fam Avg Bill	1,130	$ 146.00	Single Fam Avg Bill	1,501	$ 191.33

202401			202402			202403		
Customers	Sum of Total kWh	Sum of Billed Amount	Customers	Sum of Total kWh	Sum of Billed Amount	Customers	Sum of Total kWh	Sum of Billed Amount
85,682	75,557,434	$10,172,025.42	85,922	64,699,303	$9,319,562.47	86,301	62,400,248	$9,005,333.40
186,781	300,691,417	$40,847,359.71	186,746	251,295,345	$36,261,161.61	187,031	247,633,526	$35,727,935.80
272,463	376,248,851	$51,019,385.13	272,668	315,994,648	$45,580,724.08	273,332	310,033,774	$44,733,269.20
	Monthly kWh	Monthly Bill		Monthly kWh	Monthly Bill		Monthly kWh	Monthly Bill
Multi-Fam Avg Bill	882	$ 118.72	Multi-Fam Avg Bill	753	$ 108.47	Multi-Fam Avg Bill	723	$ 104.35
Single Fam Avg Bill	1,610	$ 218.69	Single Fam Avg Bill	1,346	$ 194.17	Single Fam Avg Bill	1,324	$ 191.03

Billing and Usage for Oregon Residential Customers with Electric Heat November 2024 to March 2025

Accounting Period	202411			202412		
Dwelling Unit Description	Customers	Sum of Total kWh	Sum of Billed Amount	Customers	Sum of Total kWh	Sum of Billed Amount
Multi-Family	88,265	49,367,597	$7,494,108.73	88,445	75,232,029	$10,866,051.49
Single Family	188,305	201,764,515	$30,218,138.74	188,582	301,843,014	$43,723,741.82
Grand Total	276,570	251,132,112	$37,712,247.47	277,027	377,075,043	$54,589,793.31
		Monthly kWh	Monthly Bill		Monthly kWh	Monthly Bill
	Multi-Fam Avg Bill	559	$ 84.90	Multi-Fam Avg Bill	851	$ 122.86
	Single Fam Avg Bill	1,071	$ 160.47	Single Fam Avg Bill	1,601	$ 231.86

202501			202502			202503		
Customers	Sum of Total kWh	Sum of Billed Amount	Customers	Sum of Total kWh	Sum of Billed Amount	Customers	Sum of Total kWh	Sum of Billed Amount
88,287	73,232,517	$10,813,925.12	88,168	79,054,537	$11,886,488.59	88,326	60,384,048	$9,251,839.36
188,464	296,451,437	$44,539,229.37	188,516	308,404,277	$47,668,091.98	188,619	233,375,371	$36,582,507.73
276,751	369,683,954	$55,353,154.49	276,684	387,458,814	$59,554,580.57	276,945	293,759,419	$45,834,347.09
	Monthly kWh	Monthly Bill		Monthly kWh	Monthly Bill		Monthly kWh	Monthly Bill
Multi-Fam Avg Bill	829	$ 122.49	Multi-Fam Avg Bill	897	$ 134.82	Multi-Fam Avg Bill	684	$ 104.75
Single Fam Avg Bill	1,573	$ 236.33	Single Fam Avg Bill	1,636	$ 252.86	Single Fam Avg Bill	1,237	$ 193.95

Billing and Usage for Oregon Residential Customers with Electric Heat November 2025 to March 2026 to date

Accounting Period	202511			202512		
Dwelling Unit Description	Customers	Sum of Total kWh	Sum of Billed Amount	Customers	Sum of Total kWh	Sum of Billed Amount
Multi-Family	91,568	48,827,669	$7,520,252.21	91,568	64,485,370	$9,555,091.80
Single Family	191,051	190,572,401	$30,119,168.13	191,185	253,548,778	$38,856,229.72
Grand Total	282,619	239,400,070	$37,639,420.34	282,753	318,034,148	$48,411,321.52
		Monthly kWh	Monthly Bill		Monthly kWh	Monthly Bill
	Multi-Fam Avg Bill	533	$ 82.13	Multi-Fam Avg Bill	704	$ 104.35
	Single Fam Avg Bill	997	$ 157.65	Single Fam Avg Bill	1,326	$ 203.24

202601			202602			202603		
Customers	Sum of Total kWh	Sum of Billed Amount	Customers	Sum of Total kWh	Sum of Billed Amount	Customers	Sum of Total kWh	Sum of Billed Amount
91,515	74,161,626	$10,775,419.53	91,489	70,126,639	$10,136,656.00	76,948	50,169,380	$7,300,067.94
191,253	290,855,592	$43,941,591.48	191,416	262,858,879	$39,628,786.94	158,166	178,330,869	$27,095,285.38
282,768	365,017,218	$54,717,011.01	282,905	332,985,518	$49,765,442.94	235,114	228,500,249	$34,395,353.32
	Monthly kWh	Monthly Bill		Monthly kWh	Monthly Bill		Monthly kWh	Monthly Bill
Multi-Fam Avg Bill	810	$ 117.74	Multi-Fam Avg Bill	767	$ 110.80	Multi-Fam Avg Bill	652	$ 94.87
Single Fam Avg Bill	1,521	$ 229.76	Single Fam Avg Bill	1,373	$ 207.03	Single Fam Avg Bill	1,127	$ 171.31