

March 1, 2022

***VIA ELECTRONIC FILING***

 Public Utility Commission Oregon  
 Attn: Filing Center  
 550 Capitol Street NE, Suite 215  
 Salem, OR 97301-2551

**RE: Advice No. 22-002/Docket UE 399 – PacifiCorp’s Request for General Rate Revision**

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) submits for filing an original and 15 copies of the following proposed tariff pages associated with the Company’s Tariff P.U.C. OR No. 36, applicable to electric service in the State of Oregon, together with the Executive Summary and supporting direct testimony and exhibits. The tariffs reflect an effective date of January 1, 2023. Electronic versions of the testimony, exhibits, and workpapers will be uploaded to Huddle.

<b><u>Sheet</u></b>	<b><u>Schedule</u></b>	<b><u>Title</u></b>
Twenty-Eighth Revision of Sheet No. INDEX-3	Tariff Index	Table of Contents - Schedules
Fourth Revision of Sheet No. 4	Schedule 4	Residential Service Delivery Service
Fourth Revision of Sheet No. 5	Schedule 5	Separately Metered Electric Vehicle Service for Residential Consumers Delivery Service
First Revision of Sheet No. 6.1	Schedule 6	Pilot for Residential Time-of-Use Service Delivery Service
Original Sheet No. 6.2	Schedule 6	Pilot for Residential Time-of-Use Service Delivery Service
Fifth Revision of Sheet No. 15-1	Schedule 15	Outdoor Area Lighting Service – No New Service Delivery Service
Fifth Revision of Sheet No. 23-1	Schedule 23	General Service – Small Nonresidential Delivery Service
Fourth Revision of Sheet No. 28-1	Schedule 28	General Service Large Nonresidential 31KW to 200 KW Delivery Service
First Revision of Sheet No. 29.1	Schedule 29	Pilot for General Service Time-Of-Use Delivery Service
Fourth Revision of Sheet No. 30-1	Schedule 30	General Service Large Nonresidential 201 KW to 999 KW Delivery Service
Fourth Revision of Sheet No. 41-1	Schedule 41	Agricultural Pumping Service Delivery Service
Fourth Revision of Sheet No. 47-1	Schedule 47	Large General Service Partial Requirements 1,000 KW and Over Delivery Service

<b>Sheet</b>	<b>Schedule</b>	<b>Title</b>
Fifth Revision of Sheet No. 48-1	Schedule 48	Large General Service 1,000 KW and Over Delivery Service
Fifth Revision of Sheet No. 51-1	Schedule 51	Street Lighting Service Company – Owned System Delivery Service
Fifth Revision of Sheet No. 53-1	Schedule 53	Street Lighting Service Consumer – Owned System Delivery Service
Fifth Revision of Sheet No. 54-1	Schedule 54	Recreational Field Lighting – Restricted Delivery Service
Fourth Revision of Sheet No. 76R-1	Schedule 76R	Large General Service – Partial Requirements Service Economic Replacement Power Rider Delivery Service
Twenty-eighth Revision of Sheet No. 90	Schedule 90	Summary of Effective Rate Adjustments
Fourteenth Revision of Sheet No. 98	Schedule 98	Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act
CANCELED First Revision of Sheet No. 104	Schedule 104	Oregon Corporate Activity Tax Recovery Adjustment
Eighth Revision of Sheet No. 200-1	Schedule 200	Base Supply Service
Eighth Revision of Sheet No. 200-2	Schedule 200	Base Supply Service
Eighth Revision of Sheet No. 200-3	Schedule 200	Base Supply Service
Tenth Revision of Sheet No. 205-1	Schedule 205	TAM Adjustment for Other Revenues
Tenth Revision of Sheet No. 205-2	Schedule 205	TAM Adjustment for Other Revenues
Tenth Revision of Sheet No. 205-3	Schedule 205	TAM Adjustment for Other Revenues
First Revision of Sheet No. 206	Schedule 206	Power Cost Adjustment Mechanism – Adjustment
First Revision of Sheet No. 207	Schedule 207	Community Solar Start-Up Cost Recovery Adjustment
Fourth Revision of Sheet No. 210-1	Schedule 210	Portfolio Time-Of-Use Supply Service
Original Sheet No. 273-1	Schedule 273	Nonresidential Accelerated Commitment Tariff (ACT)
Original Sheet No. 273-2	Schedule 273	Nonresidential Accelerated Commitment Tariff (ACT)
Original Sheet No. 273-3	Schedule 273	Nonresidential Accelerated Commitment Tariff (ACT)
Fourth Revision of Sheet No. 299	Schedule 299	Rate Mitigation Adjustment
Fourth Revision of Sheet No. 723-1	Schedule 723	General Service – Small Nonresidential Direct Access Delivery Service
Fourth Revision of Sheet No. 728-1	Schedule 728	General Service Large Nonresidential 31 KW to 200 KW Direct Access Delivery Service

<b>Sheet</b>	<b>Schedule</b>	<b>Title</b>
Fourth Revision of Sheet No. 730-1	Schedule 730	General Service Large Nonresidential 201 KW to 999 KW Direct Access Delivery Service
Fourth Revision of Sheet No.741-1	Schedule 741	Agricultural Pumping Service Direct Access Delivery Service
Fourth Revision of Sheet No. 747-1	Schedule 747	Large General Service Partial Requirements 1,000 KW and Over Direct Access Delivery Service
Fifth Revision of Sheet No. 748-1	Schedule 748	Large General Service 1,000 KW and Over Direct Access Delivery Service
Fifth Revision of Sheet No. 751-1	Schedule 751	Street Lighting Service Company-Owned System Direct Access Delivery Service
Fifth Revision of Sheet No. 753-1	Schedule 753	Street Lighting Service Consumer-Owned System Direct Access Delivery Service
Fifth Revision of Sheet No. 754	Schedule 754	Recreational Field Lighting– Restricted Direct Access Delivery Service
Fourth Revision of Sheet No. 776R-1	Schedule 776R	Large General Service-Partial Requirements Service-Economic Replacement Service Rider Direct Access Delivery Service
Second Revision of Sheet No. 848-1	Schedule 848	Large General Service 1,000 KW and Over Direct Access Delivery Service – Distribution Only
Second Revision of Sheet No. R10-1	Rule 10	General Rules and Regulations Billing

Copies of the Company’s responses to the Standard Data Requests are being uploaded to Huddle.

Please address all communications related to this filing to:

PacifiCorp Oregon Dockets  
 825 NE Multnomah Street, Suite 2000  
 Portland, OR 97232  
[oregondockets@pacificorp.com](mailto:oregondockets@pacificorp.com)

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Advice No. 22-002 / UE 399  
Public Utility Commission of Oregon  
March 1, 2022  
Page 4

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Additionally, PacifiCorp respectfully requests that all data requests in this docket be addressed to:

By email (preferred): [datarequest@pacificorp.com](mailto:datarequest@pacificorp.com)

By regular mail: Data Request Response Center  
PacifiCorp  
825 NE Multnomah, Suite 2000  
Portland, OR 97232

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

Confidential material in support of the filing has been provided to parties under the protective order issued February 11, 2022 (Order No. 22-044).

Sincerely,



Matthew McVee  
Vice President, Regulatory Policy and Operations

Enclosures

**CERTIFICATE OF SERVICE**

I certify that I delivered a true and correct copy of PacifiCorp’s **Request for General Rate Revision** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

**Service List  
UE 399**

<b>PACIFICORP</b>	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 <a href="mailto:oregondockets@pacificorp.com">oregondockets@pacificorp.com</a>	AJAY KUMAR (C) (HC) PACIFICORP 825 NE MULTNOMAH ST STE 2000 PORTLAND, OR 97232 <a href="mailto:ajay.kumar@pacificorp.com">ajay.kumar@pacificorp.com</a>
<b>STAFF</b>	
MATTHEW MULDOON (C) (HC) PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM OR 97308 <a href="mailto:matt.muldoon@state.or.us">matt.muldoon@state.or.us</a>	SOMMER MOSER (C) (HC) PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 <a href="mailto:sommer.moser@doj.state.or.us">sommer.moser@doj.state.or.us</a>

Dated this 1<sup>st</sup> day of March, 2022.



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Mary Penfield  
Adviser, Regulatory Operations

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON  
UE 399**

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

**PACIFICORP'S  
EXECUTIVE SUMMARY**

**I. INTRODUCTION**

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) is filing this request for a general rate revision under ORS 757.205 and ORS 757.220 to revise its schedules of rates and charges for electric service in Oregon, effective January 1, 2023. In this general rate case filing, the requested revenue requirement increase in this general rate case filing is \$84.4 million, or 6.8 percent. This includes the impact of moving the recovery of the Oregon Corporate Activity Tax Credit (OCAT) of \$6.7 million from a rider to recovery in base rates. The net increase including the elimination of the separate OCAT rider and the rebalancing of the rate mitigation adjustment is \$82.2 million, or 6.6 percent. The revised rates produce revenues necessary to sustain a stable, reliable, and low-cost power supply, while preserving the Company's ability to attract capital for future investments. The Company files this executive summary and the attached Exhibit A in compliance with OAR 860-022-0019.

PacifiCorp is an electric company and public utility in Oregon within the meaning of ORS 757.005. The Public Utility Commission of Oregon (Commission) has jurisdiction over the prices and terms of PacifiCorp's electric service to its Oregon retail customers. The Company provides electric service to approximately 630,000 retail customers in Oregon and approximately 2.0 million total retail customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's principal place of business is Portland, Oregon.

The Company requests that communications regarding this filing be addressed to:

PacifiCorp Oregon Dockets  
825 NE Multnomah Street, Suite 2000  
Portland, OR 97232  
[oregondockets@pacificorp.com](mailto:oregondockets@pacificorp.com)

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By regular mail: Data Request Response Center  
PacifiCorp  
825 NE Multnomah Street, Suite 2000  
Portland, OR 97232

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

## II. CASE SUMMARY

This case is based upon a historical base period of 12 months ended June 2021, with normalizing and pro forma adjustments to calculate a calendar year 2023 future test period with the exception of capital additions, which are based on calendar year-end 2022 balances. The new rates will become effective no later than January 1, 2023, assuming application of

the full nine-month statutory suspension period to the 30-day effective date now contained in the tariffs. Thus, the rate effective period closely aligns with the test period in this case.

#### **A. Return on Equity**

PacifiCorp is currently forecast to earn a return on equity (ROE) in Oregon of 4.67 percent on a normalized basis for the test period. The Company is requesting a change to its authorized ROE and capital structure in this case. An increase to the equity component of the capital structure to 52.25 percent and a 9.8 percent ROE is necessary to maintain the financial integrity of the Company, while ensuring its ability to provide safe, efficient, and reliable service to its Oregon customers with minimal rate impacts.

#### **B. Cost Drivers**

##### *1. Capital Additions*

The Company continues to make new investments in its system 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 the system—including transmission, generation, and distribution—to bolster reliability and improve power delivery. The largest of these costs is the remainder of the investment in TB Flats Wind Project, which the Commission approved as prudent and in the public interest in the Company’s last general rate case, docket UE 374 (2021 Rate Case).<sup>1</sup>

##### *2. Wildfire and Vegetation Management Costs*

With the increasing threat of wildfires in Oregon, the Commission in the 2021 Rate Case and the Oregon State Legislature through Senate Bill 762 have recognized the necessity of wildfire mitigation efforts and wildfire protection plans to a utility’s system. PacifiCorp

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<sup>1</sup> *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).



has undertaken a number of measures to mitigate the wildfire threat, which has increased capital investment and operating and maintenance expenses. Further, unrelated to the wildfire mitigation measures, the Company is incurring additional spending with respect to vegetation management as a result of increasing costs.

### 3. Modifications to Existing Regulatory Mechanisms

In PacifiCorp's 2021 Rate Case, the Commission approved a Wildfire Mitigation and Vegetation Management Recovery (WMVM) Mechanism in order to allow an opportunity for the Company to recover wildfire mitigation and vegetation management costs above the amount for vegetation management costs included in rates. PacifiCorp is proposing modifications to this mechanism—namely to remove wildfire mitigation capital investments and operation and maintenance expenses from the mechanism in light of the enactment of Senate Bill 762 and to modify the existing mechanism to better align recovery of vegetation management costs with results. The Company is also proposing modifications to its Transition Adjustment Mechanism and Power Cost Adjustment Mechanism to improve the accuracy of net power costs and to ensure the appropriate risk balance for the recovery of those costs.

## III. TESTIMONY SUMMARY

The Company's direct case consists of the testimony and exhibits of 11 witnesses:

**Joelle R. Steward**, Senior Vice President, Regulation and Customer/Community Solutions, provides an overview of PacifiCorp's current filing and support of the Company's policy positions throughout this filing. Ms. Steward also discusses the proposed updates to the Oregon depreciable lives and/or Exit Orders for certain coal-fired resources. She also discusses updates to the WMVM Mechanism.

**Nikki L. Kobliha**, Chief Financial Officer, addresses the Company's overall cost of capital recommendation for the Company, including a capital structure to maximize value and minimize risk and the current cost of debt. She also addresses the Company's pension settlement accounting.

**Ann E. Bulkley**, Principal at The Brattle Group, provides a comparison of PacifiCorp's business and financial risk compared to peer utilities, recommends a ROE, and provides supporting analyses.

**Michael G. Wilding**, Vice President, Energy Supply Management, addresses proposed changes to the Company's Transition Adjustment Mechanism and Power Cost Adjustment Mechanism.

**Timothy J. Hemstreet**, Managing Director of Renewable Energy and Business Development, provides an overview of the TB Flats Wind Project and provides an update on the status of the project.

**Richard A. Vail**, Vice President of Transmission Services, describes PacifiCorp's transmission system and the benefits it provides to Oregon customers and the major new transmission system projects included in this general rate case filing, specifically the Goshen to Sugarmill to Rigby 161 kilovolt (kV) and the Jordanelle to Midway 138 kV transmission line projects.

**Allen Berreth**, Vice President of Transmission and Distribution Operations, discusses wildfire risk and the Company's wildfire related transmission and distribution investments and vegetation management expenses included in this rate case. He also discusses the proposed revisions to the WMVM Mechanism.

**Erik Anderson**, Strategic Manager of Renewable Energy and Emerging Technology, describes PacifiCorp’s proposed voluntary renewable energy tariff for nonresidential customers, which is proposed Schedule 273, the Accelerated Commitment Tariff.

**Kenneth Lee Elder, Jr.**, Load Forecasting Manager, describes how the Company developed the load forecast used in this general rate case filing.

**Sherona L. Cheung**, Revenue Requirement Manager, summarizes the overall test period revenue requirement, pro forma adjustments, and the rate base calculation methodology.

**Robert M. Meredith**, Director of Pricing and Cost of Service, provides PacifiCorp’s allocation and rate design, and discusses how the proposed tariff changes recover the proposed 2023 revenue requirement to achieve fair, just, and reasonable prices for customers.

#### **IV. CONCLUSION**

The Company requests that the Commission issue an order approving the proposed rate changes and tariffs described above.

Respectfully submitted March 1, 2022.



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Carla Scarsella  
Deputy General Counsel

Ajay Kumar  
Senior Attorney

PacifiCorp d/b/a Pacific Power

# **Exhibit A**

**Exhibit A**  
**Summary of Requested Electric General Rate Increase**  
Oregon Allocated  
Filed March 1, 2022

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(A)	Total revenues collected under proposed rates:	\$1,044,764,668
(B)	<b><u>Base</u></b>	
	Revenue change requested:	
	Total:	\$84,399,519
	Net of credits from federal agencies:	\$84,399,519
	<b><u>Net<sup>1</sup></u></b>	
	Revenue change requested:	
	Total:	\$82,171,330
	Net of credits from federal agencies:	\$82,171,330
(C)	<b><u>Base</u></b>	
	Percentage change in revenues requested:	
	Total %:	6.8%
	Net of credits from federal agencies:	6.8%
	<b><u>Net<sup>1</sup></u></b>	
	Percentage change in revenues requested:	
	Total %:	6.6%
	Net of credits from federal agencies:	6.6%
(D)	Test period:	Calendar year 2023
(E)	Requested return on capital:	7.21%
	Requested return on equity:	9.8%
(F)	Rate base proposed in filing:	\$4,199,121,534
(G)	Results of operation:	
	Utility operating income, before proposed change:	\$190,246,188
	Utility operating income, after proposed change:	\$302,848,497

(H) Effect of rate change on each customer class:	<u>Base Change</u>	<u>Net Change</u> <sup>1</sup>
• Residential:	12.6%	9.1%
• Small General Service (Schedule 23):	10.3%	9.5%
• General Service 31-200 kW (Schedule 28):	-0.8%	0.0%
• General Service 201-999 kW (Schedule 30):	-2.4%	0.0%
• Large General Service >= 1,000 kW (Schedule 48):	-1.9%	5.9%
• Agriculture Pumping Service (Schedule 41):	19.1%	13.2%
• Street lighting:	-11.5%	0.0%
• Total	6.8%	6.6%

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

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<sup>1</sup> Net Change reflects the net impact to customers on January 1, 2023, of the proposed price change including resetting Schedule 299, the Rate Mitigation Adjustment and eliminating the separate charge for the Oregon Corporate Activity Tax Recovery Adjustment, Schedule 104. Including these adjustments, a net increase of \$82.2 million, or 6.6 percent overall, is proposed to take effect on January 1, 2023.

ACRONYMS AND ABBREVIATIONS

Acronym	Term
2020 Protocol	2020 PacifiCorp Inter-Jurisdictional Allocation Protocol
2021 Rate Case	the Company's 2021 general rate case, docket UE 374
2021 Rate Case	Docket UE 374
2022AS RFP	2022 All-Source RFP
2023 GRC	this general rate case (docket UE 399)
2023 Rate Case	this general rate case (docket UE 399)
AAC	all-aluminum conductor
ACC	Arizona Commission Corporation
ACSR	aluminum conductor steel-reinforced
ACT	Accelerated Commitment Tariff
ADIT	Accumulated Deferred Income Tax
AFUDC	Allowance for Funds Used During Construction
aMW	average Megawatts
APS	Arizona Public Service Company
ASC 715	Accounting Standards Codification Topic 715-30—Compensation—Retirement Benefits
ATTR	annual transmission revenue requirement
B.C.	British Columbia
BAA	Balancing Authority Areas
Base Period	historical period of the 12 months ended June 2021
BES	Bulk Electric System
BHE	Berkshire Hathaway Energy Company
BOSR	Body of State Regulators
CAISO	California Independent System Operator
CAPEX	capital expenditures
CAPM	Capital Asset Pricing Model
CBO	Congressional Budget Office
CFO	cash from operations
CFO pre-W/C	Cash from Operations pre-Working Capital
Commission	Public Utility Commission of Oregon
Company	PacifiCorp d/b/a Pacific Power
CPI	Consumer Price Index
DCF	Discounted Cash Flow
ECD	embedded cost differential
EDIT	Excess Deferred Income Tax
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EPA	Environmental Protection Agency
EPS	Earnings Per Share
ESM	Energy Supply Management
FERC	Federal Energy Regulatory Commission
FHCA	Fire High Consequence Areas
FOMC	Federal Open Market Committee
Functionalized Oregon Results of Operations Report	PacifiCorp's December 2021 Functionalized Oregon Results of Operations Report
GDP	Gross Domestic Product
GHG	greenhouse gas
HB	House Bill
HLH	heavy load hours
HLP	Heber Light and Power
IHS	Information Handling Services
IRP	Integrated Resource Plan
KHSA	Klamath Hydroelectric Settlement Agreement
kV	kilovolt
kWh	kilowatt-hour
LIBOR	London Inter Bank Offer Rate
Marginal Cost Study	PacifiCorp's State of Oregon December 2023 Marginal Cost Study
Michigan PSC	Michigan Public Service Commission
Mid-C	Mid-Columbia
MSP	multi-state process
MVA	Megavolt ampere
MW	megawatts

ACRONYMS AND ABBREVIATIONS

Acronym	Term
MWh	megawatt-hour
NEO	Named Executive Officers
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
Non-NPC	Non-Net Power Costs
Non-T&D	non-transmission and distribution
NPC	net power costs
NWRFC	Northwest River Forecast Center
O&M	operations and maintenance
OAR	Oregon Administrative Rule
OATT	Open Access Transmission Tariff
OCAT	Oregon Corporate Activity Tax
ORS	Oregon Revised Statute
P/E	price-to-earnings
PACE	PacifiCorp Balancing Authority Area East
PacifiCorp	PacifiCorp d/b/a Pacific Power
PACW	PacifiCorp Balancing Authority Area West
participant	nonresidential customer
PCAM	Power Cost Adjustment Mechanism
PGE	Portland General Electric Company
PHFU	Plant Held for Future Use
PPA	power purchase agreement
PTC	Production Tax Credit
PV	Palo Verde
RAS	remedial action scheme
RBM	regional business manager
REC	Renewable Energy Certificate
Report	Company's Oregon results of operations report
RFP	request for proposal
RMA	Rate Mitigation Adjustment
ROE	return on equity
ROR	Rate of Return
RPS	Renewable Portfolio Standards
RRA	Regulatory Research Associates
S&P	Standard & Poor's
SAE	Statistically Adjusted End-Use
SB	Senate Bill
SCR	selective catalytic reduction system
TAM	Transition Adjustment Mechanism
TCJA	Tax Cuts and Jobs Act
TEP	Transportation Electrification Program
Test Period	the 12-month period ending December 31, 2023
TPL Standards	transmission planning standards
U.S	United States
UAMPS	Utah Associated Municipal Power Systems
Value Line	Value Line Investment Survey
VERS	variable energy resources
Vestas	Vestas-American Wind Technology, Inc.
VRET	Voluntary Renewable Energy Tariff
WEBA	Wage and Employee Benefits adjustments
WECC	Western Electricity Coordinating Council
WMVM	Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism
WPP	Western Power Pools
WPP	Wildfire Protection Plans
WRAP	Western Resource Adequacy Program
WROE	Weighted Return on Equity
WTG	wind turbine generator
YOY	year-over-year



Docket No. UE 399  
Exhibit PAC/100  
Witness: Joelle R. Steward

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Direct Testimony of Joelle R. Steward**

**March 2022**

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**ATTACHED EXHIBIT**

Exhibit PAC/101—PacifiCorp’s Oregon Rates Compared to National Averages

1                                   **I. INTRODUCTION AND QUALIFICATIONS**

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

4   A. My name is Joelle R. Steward and my business address is 1407 West North Temple,  
5   Salt Lake City, Utah 84116. I am currently employed as Senior Vice President,  
6   Regulation and Customer/Community Solutions.

7   **Q. Please describe your education and professional experience.**

8   A. I have a Bachelor of Arts degree in Political Science from the University of Oregon  
9   and an M.A. in Public Affairs from the Hubert Humphrey Institute of Public Policy at  
10   the University of Minnesota. Between 1999 and March 2007, I was employed as a  
11   Regulatory Analyst with the Washington Utilities and Transportation Commission.  
12   I joined the Company in March 2007 as a Regulatory Manager, responsible for all  
13   regulatory filings and proceedings in Oregon. On February 14, 2012, I assumed  
14   responsibilities overseeing cost of service and pricing for PacifiCorp. In May 2015, I  
15   assumed broader oversight over Rocky Mountain Power’s regulatory affairs in  
16   addition to the cost of service and pricing responsibilities. In 2017, I assumed the  
17   role as Vice President, Regulation for Rocky Mountain Power; in November 2021, I  
18   assumed my current role as Senior Vice President, Regulation and  
19   Customer/Community Solutions for PacifiCorp.

20   **Q. Have you testified in other regulatory proceedings?**

21   A. Yes. I have testified on various matters in the states of Idaho, Oregon, Utah,  
22   Washington, and Wyoming.

**II. PURPOSE OF TESTIMONY**

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

A. I provide an overview of PacifiCorp’s current filing and support the Company’s policy positions throughout this filing. I also give context for this rate filing, which comes just over a year after the order in PacifiCorp’s last general rate case, docket UE 374 (2021 Rate Case).<sup>1</sup> The Company is facing increasing requirements regarding decarbonization in House Bill (HB) 2021 and wildfire mitigation in Senate Bill (SB) 762 and needs to have a fair opportunity to recover its prudent and reasonable costs to support access to financial markets to make investments needed to comply with state statutes and policies. The Company has and continues to make a concerted effort to manage its controllable costs, which allowed it to stay out of general rate cases beyond its commitment made in docket UE 263<sup>2</sup> until it filed its 2021 Rate Case. While the Company has been transitioning to a non-emitting energy resource mix, work needs to be done to meet the requirements of HB 2021. This work coupled with the investment required to protect its system and customers from the increasing wildfire threat and increasing costs of vegetation management, will help position the Company to continue to respond proactively and ensure delivery of safe, reliable, affordable electric service to its customers.

The requested revenue requirement increase in this general rate case filing is \$84.4 million, or 6.8 percent. This includes the impact of moving the recovery of the

<sup>1</sup> *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).

<sup>2</sup> In its 2013 Rate Case, the Company committed to not filing a rate case prior to January 1, 2016. *See In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 263, Order No.13-474, at 6 (Dec. 18, 2013). In a letter to its Oregon customers, PacifiCorp further committed not to file a general rate case prior to January 1, 2018.

1 Oregon Corporate Activity Credit (OCAT) of \$6.7 million from a rider to recovery in  
2 base rates. The net increase including the elimination of the separate OCAT rider and  
3 the rebalancing of the rate mitigation adjustment, which is discussed further in the  
4 testimony of Mr. Robert M. Meredith, is \$82.2 million, or 6.6 percent.

5 **Q. How is your testimony structured?**

6 A. Section III of my testimony provides a description of PacifiCorp and its Oregon  
7 service territory. Section IV provides an overview of PacifiCorp's last rate case  
8 filing. Section V provides an overview of this rate case filing, including a discussion  
9 of key drivers. Section VI discusses the Company's proposed revisions to the  
10 depreciable lives and / or Exit Orders for certain coal-fueled generation units  
11 approved in the 2021 Rate Case. Section VII discusses the proposed modifications to  
12 the Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism  
13 (WMVM Mechanism). Section VIII addresses PacifiCorp's proposed Voluntary  
14 Renewable Energy Tariff (VRET) which is called the Accelerated Commitment Tariff  
15 (ACT) program. Section IX addresses the proposed limited modifications to the  
16 Transition Adjustment Mechanism (TAM) Rate Year Update and the proposed  
17 revisions to the TAM guidelines and Power Cost Adjustment Mechanism (PCAM).  
18 Finally, Section X introduces the witnesses submitting testimony in support of  
19 PacifiCorp's rate case filing.

20 **Q. Please summarize the recommendations you make in your direct testimony.**

21 A. I recommend that the Public Utility Commission of Oregon (Commission):

- 1           • Authorize an overall increase of \$84.4 million or approximately 6.8 percent. The  
2           support for the increase is set forth in my testimony and the testimony of the other  
3           Company witnesses;
- 4           • Approve as prudent the Company’s request to include the incremental additions to  
5           the Company’s rate base, including the remaining portion of the TB Flats Wind  
6           Project, for a total rate base of approximately \$4.2 billion, as discussed in the  
7           testimony of various witnesses in this rate case;
- 8           • Approve an overall cost of capital of 7.21 percent, which is comprised of a capital  
9           structure of 52.25 percent equity, 47.74 percent long-term debt, and 0.01 percent  
10          preferred stock as supported by Ms. Nikki L. Kobliha; and a return on equity (ROE)  
11          of 9.8 percent as supported by Ms. Ann E. Bulkley;
- 12          • Approve the proposed updates to the Oregon depreciable lives and/or revisions to  
13          the Exit Orders for coal-fired resources approved in the 2021 Rate Case to align  
14          with the Company’s 2021 Integrated Resource Plan (IRP) as described in my  
15          testimony;
- 16          • Approve the proposed revisions to the WMVM Mechanism as discussed in my  
17          testimony and the testimony of Mr. Allen Berreth;
- 18          • Approve PacifiCorp’s proposed VRET, the ACT, Schedule 273, as discussed in my  
19          testimony and the testimony of Mr. Erik Anderson;
- 20          • Approve the proposed modifications to the TAM and the proposed revisions to the  
21          TAM guidelines and PCAM as explained by Mr. Michael G. Wilding; and
- 22          • Approve the cost allocations and rate design proposals set forth in the testimony of  
23          Mr. Meredith.

1           **III.   DESCRIPTION OF PACIFICORP AND OREGON SERVICE AREA**

2   **Q.   Please provide a brief description of PacifiCorp.**

3   A.   As an investor-owned, multi-jurisdictional electric utility, PacifiCorp serves two  
4       million customers in six western states: California, Idaho, Oregon, Utah,  
5       Washington, and Wyoming.

6           The Company serves its customers with a vast, integrated system of  
7       generation and transmission that spans 10 states and connects customers and  
8       communities across the West. PacifiCorp’s integrated system provides benefits to  
9       customers in all six states and includes generation, transmission, and distribution  
10      assets. PacifiCorp owns, or has interests in thermal, hydroelectric, wind-powered,  
11      solar, and geothermal generating facilities, with a net-owned capacity of 11,668  
12      megawatts. PacifiCorp buys and sells electricity on the wholesale market with other  
13      utilities, energy marketing companies, financial institutions, and other market  
14      participants to balance and optimize the economic benefits of electricity generation,  
15      retail customer loads, and existing wholesale transactions.

16           PacifiCorp provides wholesale transmission service under its open access  
17      transmission tariff approved by the Federal Energy Regulatory Commission and owns  
18      or has interests in approximately 17,700 miles of transmission lines. PacifiCorp  
19      operates two Balancing Authority Areas—PacifiCorp Balancing Authority Area East  
20      and PacifiCorp Balancing Authority Area West that together comprise the largest  
21      privately owned and operated grid in the Western United States.

1 **Q. Please describe PacifiCorp’s Oregon service area.**

2 A. In Oregon, PacifiCorp serves approximately 630,000 customers. The Company’s  
3 Oregon service area is comprised of urban and rural areas. PacifiCorp’s sales and  
4 revenues are distributed among residential customers, small businesses, and large  
5 businesses served under retail tariffs subject to the jurisdiction of the Commission.  
6 Table 1 below provides the June 2021 number of retail customers and usage by  
7 customer class.

8 **Table 1: Number of Customers and Usage in PacifiCorp’s Oregon Service Area**

Class	Number of Customers	Usage (megawatt-hours)
Residential	539,475	5,901,942
Commercial	80,387	5,654,081
Industrial	1,711	1,601,028
Irrigation	6,578	303,317
Lighting	1,467	35,659
Total	629,618	13,496,028

9 **IV. PREVIOUS RATE CASE HISTORY**

10 **Q. Please discuss PacifiCorp’s most recent general rate case and its outcome.**

11 A. On February 14, 2020, the Company filed its 2021 Rate Case requesting an increase  
12 in revenues from Oregon operations of \$78.0 million or a 6 percent increase to its  
13 revenue requirement.<sup>3</sup> During the course of the proceeding, as a result of  
14 adjustments, PacifiCorp revised its request to an increase of \$46.3 million or  
15 approximately 3.5 percent.<sup>4</sup> Following a fully litigated proceeding, on

<sup>3</sup> The overall impact to customer rates in the Company’s direct filing was an increase of \$21.6 million or 1.6 percent, which reflected an increase in revenue requirement of \$78.0 million; an increase related to the recovery of costs associated with the closing of Cholla Unit 4 of \$17.3 million; a decrease of \$24.9 million to amortize deferred tax benefits associated with the Tax Cuts and Jobs Act; and a decrease of \$49.2 million related to the concurrently filed 2021 TAM, Docket No. UE 375.

<sup>4</sup> Order 20-473 at 1.



1 December 18, 2020, the Commission entered an order approving a decrease to  
2 PacifiCorp's revenue requirement of \$20.9 million or 1.6 percent.<sup>5</sup>

3 **Q. Why is PacifiCorp filing a rate case just over a year after the issuance of the**  
4 **Commission's Order 20-473 in the 2021 Rate Case?**

5 A. The Commission made a number of important findings in Order 20-473 to provide  
6 PacifiCorp an opportunity to recover its prudently incurred costs going forward. The  
7 Commission approved full recovery of and on the vast majority of the Company's  
8 capital investments, including the Energy Vision 2020 projects that increased  
9 PacifiCorp's non-emitting generation portfolio with new and repowered wind  
10 generation resources and new transmission. The Commission also adopted the  
11 WMVM Mechanism to allow the Company the opportunity to recover capital costs  
12 and operations and maintenance (O&M) expenses above the amounts approved in the  
13 revenue requirement.

14 However, despite the findings in Order 20-473, PacifiCorp is still under-  
15 recovering costs as demonstrated by the fact that under current rates the Company  
16 will earn an overall ROE in Oregon of 4.67 percent, which is significantly below the  
17 Company's currently authorized ROE of 9.5 percent. It is important that the  
18 Company has the opportunity to recover its prudently incurred costs, particularly in  
19 light of enactment of HB 2021, which requires PacifiCorp to reduce emissions  
20 associated with the electricity it delivers -- 80 percent by 2030, 90 percent by 2035,  
21 and completely eliminate emissions by 2040.

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<sup>5</sup> *Id.*

1           PacifiCorp has been transitioning to a non-emitting energy resource mix while  
2 continuing to provide safe, reliable, and affordable electric service to its customers.  
3 The Company's 2021 IRP preferred portfolio includes retirement of 14 of the coal-  
4 fueled generation units by 2030 and 19 of the units by the end of the planning period  
5 of 2040.<sup>6</sup> This is in addition to the recently closed units, including Carbon Units  
6 1 and 2, and Cholla Unit 4, and the conversion of Naughton Unit 3 to natural gas.  
7 As reliance on coal-fueled generation is decreasing, an increasing segment of the  
8 Company's resource mix is renewable generation. In its 2013 IRP, renewable  
9 resources made up only 1.5 percent of PacifiCorp's resource capacity.<sup>7</sup>  
10 In its 2021 IRP, PacifiCorp forecasts 34 percent of its resource capacity will be  
11 renewable energy resources and 30 percent coal-fueled generation by 2023.<sup>8</sup>

12           The Company's 2021 IRP was not prepared pursuant to HB 2021 as the  
13 2021 IRP was issued before the new law became effective in September 2021.  
14 Further, it is my understanding that HB 2021 applies to IRPs issued after January 1,  
15 2022.<sup>9</sup> Significant capital investment will be needed to meet the requirements of HB  
16 2021 and the Company must be well positioned to have the opportunity to recover its  
17 prudent costs and have access to capital markets to finance these investments.  
18 Therefore, the Company has filed this rate case to recover prudently incurred capital  
19 costs incurred since the 2021 Rate Case, such as the remaining investment in the TB  
20 Flats Wind Project, along with reasonable O&M expenses, including vegetation  
21 management; to adjust capital structure so that the Company can maintain its current

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<sup>6</sup> PacifiCorp's 2021 IRP at 299. See, <https://www.pacificorp.com/energy/integrated-resource-plan.html>.

<sup>7</sup> PacifiCorp's 2013 IRP at 229 (Apr. 30, 2013).

<sup>8</sup> PacifiCorp's 2021 IRP at 305.

<sup>9</sup> HB 2021, Section 4(3)(a).

1 credit rating; and to request revisions to certain cost recovery mechanisms, such as  
2 the WMVM Mechanism, TAM, and PCAM. I explain the drivers of this rate case  
3 filing further below. Along with the other witnesses sponsoring direct testimony in  
4 this proceeding, I support the Company's proposals.

5 **Q. How does PacifiCorp's current and proposed overall retail average rate in**  
6 **Oregon compare to the national average?**

7 A. PacifiCorp's efficient operations and focus on rate stability for customers have  
8 resulted in the Company's average price being approximately 18 percent lower than  
9 the national average of 11.20 cents per kWh for the 12 months ending  
10 June 30, 2021, as reported by the Edison Electric Institute Summer 2021 Typical Bills  
11 and Average Rates Report. Attached to my testimony as Exhibit PAC/101 is a chart  
12 comparing PacifiCorp's Oregon rates to national averages.  
13 Even with its proposed rates in this proceeding, the Company's rates would remain  
14 about 12 percent lower than the national average.

15 **V. OVERVIEW OF RATE CASE**

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

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

19 **Q. What test period is the Company proposing in this rate proceeding?**

20 A. The test period the Company is proposing is a fully forecasted test year for the  
21 12 months ended December 31, 2023, with the exception of capital additions, which  
22 are based on calendar year-end 2022 balances. The testimony of Ms. Sherona L.  
23 Cheung discusses the development of the test year.

1 **Q. What rate of return is PacifiCorp requesting in this case?**

2 A. The Company is requesting approval of an overall rate of return of 7.21 percent.  
3 The overall rate of return is comprised of a 9.8 percent ROE as supported by  
4 Ms. Bulkley. As explained by Ms. Koblaha, PacifiCorp is requesting approval of a  
5 capital structure that is comprised of 52.25 percent equity, 47.74 percent long-term  
6 debt, and 0.01 percent of preferred stock. Together, this results in a weighted ROE of  
7 5.12 percent. Notably, the Company is requesting an authorized ROE below the  
8 range recommended by Ms. Bulkley. The Company's proposed capital structure  
9 balances the prevailing market conditions that support a higher ROE, as described by  
10 Ms. Bulkley, with the Company's capital financing needs and impacts on customers.  
11 Ms. Cheung applies the overall rate of return to the Company's cost of service.

12 **Q. Please describe the major drivers of PacifiCorp's rate request.**

13 A. The major drivers of the Company's general rate case filing are: (1) the remainder of  
14 the TB Flats Wind Project; (2) wildfire and vegetation management costs; and (3)  
15 modifications to existing regulatory mechanisms. I discuss each of these drivers in  
16 more detail below.

17 **Q. Please describe the driver related to the TB Flats Wind Project in this rate  
18 request.**

19 A. Currently, a portion of the costs of the TB Flats Wind Project are already reflected in  
20 rates. In the 2021 Rate Case, the TB Flats Wind Project was found prudent and in the  
21 public interest. Due to construction delays associated with COVID-19, the entire  
22 project was not completed in 2020 and only costs associated with turbines that  
23 achieved commercial operation by December 20, 2020, were included in rates. The

1 Project was completed in July 2021 and in this proceeding the Company is seeking to  
2 include the remainder of the investment in TB Flats Wind Project in rates. Please see  
3 Mr. Timothy J. Hemstreet’s testimony for further discussion of costs associated with  
4 the remainder of the investment in TB Flats Wind Project.

5 **Q. Please describe the driver related to wildfire mitigation and vegetation**  
6 **management costs.**

7 A. Both the Commission in Order 20-473 and the Oregon State Legislature in SB 762  
8 have recognized the importance of wildfire mitigation/wildfire protection plans to all  
9 Oregonians as a result of the increasing wildfire risk in the state.<sup>10</sup> As a result, the  
10 Company has undertaken a number of measures to mitigate wildfire threat which has  
11 increased capital investment and O&M expenses. Furthermore, the Company is  
12 incurring additional spending related to vegetation management that is unrelated to  
13 wildfire mitigation as a result of an escalation in costs and change in program  
14 activities. Mr. Berreth discusses wildfire and vegetation management costs further in  
15 his testimony.

16 **Q. Please describe the driver related to existing regulatory mechanisms.**

17 A. PacifiCorp is not being afforded a fair opportunity to recover its costs in two major  
18 cost categories for which the Commission has established specific recovery  
19 mechanisms: wildfire and vegetation management costs and net power costs (NPC).  
20 With respect to wildfire and vegetation management costs, the Company is proposing  
21 two modifications to the WMVM Mechanism—namely to remove the costs  
22 associated with Company’s wildfire protection plan from the mechanism and to

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<sup>10</sup> See Order 20-473 at 120-125 and SB 762.

1 modify the existing mechanism to better align recovery of vegetation management  
2 costs with results. As to NPC, in this proceeding the Company is proposing limited  
3 modifications to the TAM and PCAM to improve the accuracy of NPC and to ensure  
4 the appropriate risk balance for the recovery of NPC. Mr. Berreth and I both address  
5 the proposed modifications to the WMVM Mechanism in our respective testimonies.  
6 Mr. Wilding discusses the limited modifications to the TAM and PCAM in his  
7 testimony.

8 **Q. Is PacifiCorp seeing inflationary increases in this rate case?**

9 A. Yes. In developing revenue requirement, the Company projects inflationary increases  
10 or decreases in costs based on third-party IHS Markit indices. These indices have  
11 changed since the Company's 2021 Rate Case as inflation is rising. In the Company's  
12 filing, inflation accounts for approximately \$8.4 million or 0.8 percent of the  
13 requested total non-NPC revenue requirement. Ms. Cheung incorporates the impact  
14 of inflation on revenue requirement in her testimony.

15 **Q. Is the Company requesting to include the final decommissioning cost estimates**  
16 **from the 2021 Rate Case in this proceeding?**

17 A. No. In its 2021 Rate Case, the Commission approved PacifiCorp's motion to expand  
18 the scope of the proceeding to include the determination of the depreciation rates,  
19 including decommissioning costs, for its coal-fueled resources and allow PacifiCorp  
20 to supplement its filing with materials submitted in docket UM 1968, the Company's  
21 then pending depreciation proceeding.<sup>11</sup> In Order 20-473, the Commission found that

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<sup>11</sup> Docket No. UE 374, ALJ Ruling (Apr. 2, 2020); see also, *In the matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates*, Docket No. UM 1968, Order No. 20-470 (Dec. 16, 2020).

1 a separate proceeding should be opened to determine final decommissioning cost  
2 estimates.<sup>12</sup> Thus, on July 8, 2021, PacifiCorp filed an application for authority to  
3 implement a decommissioning cost recovery adjustment and coal removal  
4 mechanism, which initiated docket UM 2183.<sup>13</sup> In that proceeding, the parties are  
5 working on agreed-to language for the independent evaluator request for proposal  
6 (RFP) and modified protective order and the Company expects to issue the  
7 independent evaluator RFP to market shortly. At this time, the Company is not  
8 seeking to consolidate these two proceedings.

9 **Q. Is PacifiCorp requesting to consolidate other applications with this rate case**  
10 **proceeding?**

11 A. Yes. After this rate case filing, the Company will file a motion to consolidate a  
12 number of open deferral applications to establish ratemaking treatment for these items  
13 in this rate case. These applications include:

- 14 • Docket UM 1964, Deferred Accounting for PacifiCorp's Transportation  
15 Electrification Program;<sup>14</sup>
- 16 • Docket UM 2134, Deferred Accounting for costs associated with  
17 Cedar Springs 2;<sup>15</sup>

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<sup>12</sup> Order No. 20-473 at 17.

<sup>13</sup> *In the Matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement a Decommissioning Cost Recovery Adjustment and Coal removal Mechanism*, Docket No. UM 2183, Application (July 8, 2021).

<sup>14</sup> *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for a Balancing Account Related to PacifiCorp's Transportation Electronification Program*, Docket No. UM 1964, Application filed July 27, 2018 (corrected on Jan. 27, 2022), reauthorizations filed on Mar. 24, 2020 (corrected on Jan. 27, 2022) and Mar. 23, 2021 (corrected on Jan. 27, 2022).

<sup>15</sup> *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120*, Docket No. UM 2134, Application filed Dec. 10, 2020.

- 1           • Docket UM 2142, Deferred Accounting for costs associated with Cholla Unit 4  
2           property taxes;<sup>16</sup>
- 3           • Docket UM 2167, Deferred Accounting for revenues associated with Renewable  
4           Energy Credits (RECs) from Pryor Mountain;<sup>17</sup>
- 5           • Docket UM 2185, Deferred Accounting for costs associated with Non-Contributory  
6           Defined Benefit Pensions Plans;<sup>18</sup> and
- 7           • Docket UM 2186, Deferred Accounting for the costs associated with the TB Flats  
8           Wind Project.<sup>19</sup>

9           Receiving Commission decisions on these applications to allow amortizing these  
10          deferred costs is an important step in ensuring the Company can adequately recover  
11          its prudent and reasonable expenses.

12   **Q.    Is PacifiCorp proposing major updates to rate spread and rate design?**

13    A.    No, because the Commission approved a stipulation among certain parties regarding  
14          rate spread and rate design in Order 20-473,<sup>20</sup> the Company is only proposing discrete  
15          changes to how rates are currently designed. PacifiCorp is proposing that the price  
16          change resulting from this proceeding be applied on an equal percentage basis across  
17          prices for each class of schedules, except the residential class. For the residential

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<sup>16</sup> *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for a Balancing Account Related to PacifiCorp's Transportation Electronification Program*, Docket No. UM 1964, Application filed July 27, 2018.

<sup>17</sup> *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Revenues Associated with RECs from Pryor Mountain*, Docket No. UM 2167, Application filed May 13, 2021.

<sup>18</sup> *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pensions Plans*, Docket No. UM 2185, Application filed July 27, 2021.

<sup>19</sup> *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Costs Related to a Renewable Resource Pursuant to ORS 469A.120*, Docket No. UM 2186, Application filed July 27, 2021.

<sup>20</sup> Order No. 20-473 at 140 and Appendix A.



1 class, the Company proposes increasing the single-family basic charge from \$9.50 to  
2 \$12 per month and replacing the inverted block energy charge structure with seasonal  
3 rates where winter prices are lower than summer prices. The rate design proposals  
4 are discussed in Mr. Meredith's direct testimony.

5 **VI. DEPRECIABLE LIVES AND/OR EXIT ORDERS AND EXIT DATES FOR**  
6 **CERTAIN COAL-FUELED PLANTS**

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

8 A. In this section of my testimony, I explain PacifiCorp's proposal regarding updates to  
9 the depreciable lives and/or Exit Orders of certain coal-fueled generation plants  
10 approved in the 2021 Rate Case.

11 **Q. What is an "Exit Order"?**

12 A. My understanding of Oregon energy policy, specifically, Section 1 of SB 1547, is that  
13 utilities are to eliminate the costs and benefits of coal-fueled resources from retail  
14 electric rates on or before January 1, 2030.<sup>21</sup> Thus, the 2020 PacifiCorp Inter-  
15 Jurisdictional Allocation Protocol (2020 Protocol), which was approved by the  
16 Commission on January 23, 2020,<sup>22</sup> details the process by which Oregon can exit  
17 coal-fueled resources by a date certain.

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<sup>21</sup> Chapter 028, 2016 Laws, SB 1547, Section 1, Elimination of Coal from Electric Supply.

<sup>22</sup> *In the matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, Order No. 20-024 (Jan. 23, 2020).

1 Section 4.1 of the 2020 Protocol outlines a process by which state  
2 commissions may issue “Exit Orders”<sup>23</sup> that provide for specific “Exit Dates,”<sup>24</sup> after  
3 which the state will no longer receive any benefits or be subject to any new costs  
4 related to the resource for which the Exit Order was issued. The 2020 Protocol states  
5 that Exit Orders may be established through the approval of the 2020 Protocol, in  
6 depreciation dockets, general rate cases, or other appropriate regulatory proceedings.

7 In requesting approval of the 2020 Protocol, the Company did not request, and  
8 the Commission did not approve, issuance of Exit Orders or Exit Dates for coal-  
9 fueled resources.<sup>25</sup> Instead, in its 2021 Rate Case, the Company requested the  
10 Commission issue Exit Orders with specific Exit Dates for the majority of  
11 PacifiCorp’s coal-fueled resources. However, the Commission opted to issue Exit  
12 Orders with specific Exit Dates for a subset of units requested by the Company,  
13 including Cholla Unit 4, Jim Bridger Unit 1, Craig Units 1 and 2, Naughton Units 1  
14 and 2, Colstrip Units 3 and 4, and Dave Johnston Units 1 through 4.<sup>26</sup>

15 **Q. Please identify the coal-fueled generation units for which PacifiCorp is**  
16 **requesting updates to depreciable lives and/or Exit Orders.**

17 A. PacifiCorp is requesting updates to the depreciable lives and/or Exit Orders for the  
18 following units: Colstrip Units 3 and 4; Craig Unit 2; Hayden Units 1 and 2; and Jim  
19 Bridger Units 1 and 2.

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<sup>23</sup> Exit Order means an order entered by a state commission approving the discontinuation of the use of an existing resource and exclusion of costs and benefits of that resource from customer rates by that state on a date certain. See Appendix A to the 2020 Protocol for the defined term as used in the 2020 Protocol.

<sup>24</sup> Exit Date means the date on which PacifiCorp will discontinue the allocation and assignment of costs and benefits of a coal-fueled Interim Period Resource to the State issuing the Exit Order, as defined in the 2020 Protocol.

<sup>25</sup> See Order No. 20-024, at 7-8.

<sup>26</sup> Order No. 20-473 at 12.

1 **Q. Why is PacifiCorp proposing updates for these units?**

2 A. Since Order 20-473, the Company has issued its 2021 IRP, which reflects the most  
3 current information on the retirement of the Company’s coal-fueled generation units.  
4 Table 2 below compares the depreciable lives and Exit Orders approved by the  
5 Commission in Order 20-473 and the retirement dates identified in the 2021 IRP for  
6 Colstrip Units 3 and 4; Craig Unit 2; Hayden Units 1 and 2; and Jim Bridger Units 1  
7 and 2.

8 **Table 2: Comparison of Depreciable Lives and Exit Order dates to the Retirement**  
9 **Dates Identified in the 2021 IRP**

<b>Coal Plant/Unit</b>	<b>Oregon Depreciable Life<sup>27</sup></b>	<b>Oregon Exit Orders<sup>28</sup></b>	<b>2021 IRP Retirement<sup>29</sup></b>
Colstrip 3-4	2027	2027	2025
Craig 2	2026	2026	2028
Hayden 1	2023	N/A	2028
Hayden 2	2023	N/A	2027
Jim Bridger 1	2023	2023	Convert to Gas
Jim Bridger 2	2025	N/A	Convert to Gas

10 **Q. What is the Company’s proposal regarding Colstrip Units 3 and 4?**

11 A. In Order 20-473, the Commission approved Exit Orders with Exit Dates of  
12 December 31, 2027 for Colstrip Units 3 and 4.<sup>30</sup> However, the Commission urged  
13 PacifiCorp to evaluate whether an earlier exit for these units is economic for its  
14 Oregon customers in the Company’s 2021 IRP.<sup>31</sup> Of the 22 coal-fueled generation

<sup>27</sup> Order No. 20-473 at 97; *see also*, *In the matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates*, Docket No. UM 1968, Order No. 20-470 (Dec. 16, 2020).

<sup>28</sup> Order No. 20-473 at 12; the Commission declined to issue exit orders for Hayden Units 1 and 2 and Jim Bridger 2.

<sup>29</sup> 2021 IRP at 15; *see* <https://www.pacificcorp.com/energy/integrated-resource-plan.html>.

<sup>30</sup> Order No. 20-473 at 12.

<sup>31</sup> *Id.*, 12-13.

1 units currently serving PacifiCorp customers, the 2021 IRP preferred portfolio  
2 includes retirement of 14 units by 2030 and 19 units by the end of the planning  
3 period.<sup>32</sup> Specifically, the 2021 IRP preferred portfolio accelerates the retirement of  
4 Colstrip Units 3 and 4 to 2025 instead of a retirement date of 2027 as used in the 2019  
5 IRP.<sup>33</sup> Thus, PacifiCorp's 2021 IRP Action Plan Item 1(a) is to work closely with co-  
6 owners of Colstrip Units 3 and 4 to seek the most cost effective path forward toward  
7 the target exit date of December 31, 2025.<sup>34</sup>

8 Because of the earlier target retirement date, PacifiCorp proposes that the  
9 depreciable lives for Colstrip Units 3 and 4 be updated to reflect the new 2025  
10 retirement. Approval of the updated depreciable life for these units is appropriate as  
11 it satisfies the matching principle and avoids intergenerational equity issues because  
12 the Company's proposal recovers plant investment from customers who are benefiting  
13 from the generation prior to retirement of the unit. See Ms. Cheung's direct  
14 testimony with respect to the calculation of the revenue requirement using the  
15 updated depreciable lives. The Company is not requesting that the Exit Order  
16 approved in Order 20-473 for Colstrip Units 3 and 4 be updated at this time until  
17 discussions with the joint owners of these units provide more certainty on the closure  
18 dates. As reflected in the 2021 IRP, PacifiCorp, which is a minority owner in these  
19 units, will work closely with co-owners of Colstrip Units 3 and 4 to seek the most  
20 cost-effective path forward toward the target exit date of December 31, 2025 for these  
21 units.

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<sup>32</sup> 2021 IRP at 299.

<sup>33</sup> *Id.*

<sup>34</sup> *Id.* at 321.

1 **Q. What is the Company's proposal regarding Craig Unit 2?**

2 A. In July 2020, the joint owners of Craig Unit 2 announced plans to retire this unit on  
3 September 30, 2028. The new retirement date for Craig Unit 2 was included in  
4 PacifiCorp's 2021 IRP preferred portfolio.<sup>35</sup> However, in the 2021 Rate Case, the  
5 Commission approved depreciation rates based on a 2026 depreciable life and an Exit  
6 Order with an Exit Date of December 31, 2026.<sup>36</sup> As a result, PacifiCorp proposes to  
7 extend the depreciable life for Craig Unit 2 to 2028. Approval of the updated  
8 depreciable life for this unit is appropriate as it satisfies the matching principle and  
9 avoids intergenerational equity issues because the Company's proposal matches the  
10 recovery of the plant investment to customers who are benefiting from the generation  
11 prior to retirement of the unit. See Ms. Cheung's direct testimony with respect to the  
12 calculation of the revenue requirement using the updated depreciable life.

13 Additionally, the Company requests that the Exit Order approved in Order 20-  
14 473 for Craig Unit 2 be updated to reflect an Exit Date of September 30, 2028. This  
15 change will result in a common closure date for all the Company's jurisdictions for  
16 Craig Unit 2.

17 **Q. What is the Company's proposal regarding Hayden Units 1 and 2?**

18 A. In the 2021 Rate Case, PacifiCorp did not request Exit Orders with Exit Dates for  
19 Hayden Units 1 and 2. The Commission-approved depreciable lives for Hayden  
20 Units 1 and 2 is 2023. Per Section 4.1.5 of the 2020 Protocol, on or before  
21 February 1, 2021, the Company had to make state-specific recommendations to the  
22 various state commissions for treatment of Hayden Units 1 and 2. On February 1,

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<sup>35</sup> 2021 IRP at 299.

<sup>36</sup> Order No. 20-473 at 12, 97.

1 2021, PacifiCorp filed a letter with the Commission in docket UM 1050 that notified  
2 the Commission that the joint owners of Hayden Units 1 and 2 announced the  
3 retirement of Hayden Unit 1 on December 31, 2028, and Hayden Unit 2 on  
4 December 31, 2027.<sup>37</sup> As a result, the new retirement dates for these units were  
5 included in PacifiCorp's 2021 IRP preferred portfolio.<sup>38</sup>

6 PacifiCorp proposes to update the depreciable lives for Hayden Units 1 and 2  
7 to correspond with their planned retirements. Updating the depreciable lives is  
8 consistent with the matching principle and avoids intergenerational equity issues by  
9 matching the recovery of the plant investment to customers who are benefiting from  
10 the generation prior to retirement of the unit. See Ms. Cheung's direct testimony with  
11 respect to the calculation of the revenue requirement using the updated depreciable  
12 lives.

13 Further, the Company requests that the Commission issue Exit Orders with  
14 Exit Dates for Hayden Units 1 and 2 of December 31, 2028, and December 31, 2027,  
15 respectively. Per the joint owners planned retirement and the 2021 IRP, the Company  
16 anticipates that these units will cease operation by the requested Exit Dates. It is  
17 appropriate for the Commission to issue Exit Orders for the Hayden units at this time  
18 as it provides certainty with regard to PacifiCorp's compliance with SB 1547.  
19 For coal-fueled resources anticipated to cease operations before December 31, 2029,  
20 issuance of Exit Orders now provides a clear pathway for PacifiCorp to remove the  
21 costs of these units from rates consistent with the cessation of operations.

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<sup>37</sup> Docket No. UM 1050, Letter Regarding PacifiCorp Notice of Plan for Hayden Units 1 and 2 (Feb. 1, 2021).

<sup>38</sup> 2021 IRP at 299.

1 **Q. What actions follow the issuance of an Exit Order for a specific coal-fired**  
2 **resource by one or more states?**

3 A. An Exit Order triggers certain actions identified in the 2020 Protocol, including the  
4 establishment of decommissioning cost obligations for exiting states, a potential  
5 process for the determination of capital addition responsibility, and a process for the  
6 consideration of reassignment of the freed-up capacity to other states that have not  
7 issued Exit Orders. The 2020 Protocol envisions that sufficient time, at least four  
8 years, is provided from the issuance of an Exit Order to the Exit Date to allow for  
9 reassignment of the exiting state's share of the coal-fired resource to be considered by  
10 other states. The Exit Order alone does not provide for reassignment, or any  
11 associated shift in responsibility for future operation and maintenance or capital costs  
12 and reassignment of costs and benefits must be approved by states without Exit  
13 Orders in order for cost responsibility to shift among states and for benefits of the  
14 resource to accrue to a different state.

15 **Q. How will PacifiCorp remove the Hayden Units 1 and 2 from electric rates?**

16 A. In its 2021 Rate Case, the Company had proposed a Generation Plant Removal  
17 Mechanism to recover the closure costs for coal-fueled resources that received Exit  
18 Orders. In Order 20-473, the Commission declined to approve a mechanism and  
19 decided that it would evaluate a cost recovery mechanism for closure costs associated  
20 with retired coal-fueled generation units at the conclusion of a proceeding to review  
21 PacifiCorp's decommissioning costs, as a recovery mechanism will also need to be in  
22 place to recover those costs as well.<sup>39</sup> Thus, on July 8, 2021, PacifiCorp filed an

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<sup>39</sup> Order No. 20-473 at 20-21.

1 application for authority to implement a decommissioning cost recovery adjustment  
2 and coal removal mechanism, which initiated docket UM 2183.<sup>40</sup> The recovery of  
3 retired coal-fueled generation units will be addressed in docket UM 2183.

4 **Q. What is the Company's proposal regarding Jim Bridger Units 1 and 2?**

5 A. In Order 20-473, the Commission approved an Exit Order with an Exit Date of  
6 December 31, 2023, for Jim Bridger Unit 1 and declined to approve an Exit Order  
7 with an Exit Date for Jim Bridger Units 2 through 4.<sup>41</sup> However, the Company's  
8 2021 IRP preferred portfolio includes conversion of Units 1 and 2 to natural gas  
9 peakers in 2024.<sup>42</sup> As a result, the 2021 IRP action plan's Item 1(c) includes initiating  
10 the process of ending coal-fueled operations at Jim Bridger Units 1 and 2 and seek  
11 permitting for natural gas conversion by 2024.<sup>43</sup>

12 Because of the gas conversions for Jim Bridger Units 1 and 2, Exit Orders  
13 with Exit Dates are no longer needed for these units. However, because an Exit Order  
14 was approved for Jim Bridger Unit 1 and to allow for a gas conversion, PacifiCorp  
15 requests that the Commission modify the Exit Order approved in Order 20-473 to  
16 specify that the Exit Order only applies to Jim Bridger Unit 1 as a coal-fueled  
17 resource. This modification is appropriate because it will allow the Company to  
18 operate Jim Bridger Unit 1 as a natural gas-fueled generation unit after 2023,  
19 allowing for the units to continue providing benefits to Oregon customers and remain  
20 in Oregon rates

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<sup>40</sup> Docket No. UM 2183.

<sup>41</sup> Order No. 20-473 at 12-13.

<sup>42</sup> 2021 IRP at 299.

<sup>43</sup> *Id.*, 322.



1 **Q. Has the forecasted cost of the gas conversion of Jim Bridger Units 1 and 2 been**  
2 **included for recovery in this rate case filing?**

3 A. No. Because of the timing of the project, PacifiCorp will seek recovery of the capital  
4 costs associated with the gas conversion of Jim Bridger Units 1 and 2 in a future  
5 general rate case where the Commission can review the prudence and reasonableness  
6 of those costs.

7 **VII. WILDFIRE MITIGATION AND VEGETATION MANAGEMENT COST**  
8 **RECOVERY MECHANISM**

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

10 A. In this section of my testimony, I discuss PacifiCorp's proposed changes to the  
11 WMVM Mechanism that was approved in the 2021 Rate Case.

12 **Q. Please explain the WMVM Mechanism.**

13 A. The WMVM Mechanism approved in Order 20-473 allows the Company recovery of  
14 capital costs and O&M expenses related to wildfire mitigation and vegetation  
15 management for a period of three years (2021 through 2023).<sup>44</sup> The first filing  
16 PacifiCorp will make under the mechanism will be on May 5, 2022, for recovery of  
17 2021 costs, with a rate effective date of November 5, 2022. Under the mechanism,  
18 the first \$6.645 million of capital costs and O&M expenses above the \$30 million of  
19 O&M expenses that is included in the Company's rates is recoverable based on an  
20 earnings test that is scaled based on the Company meeting certain performance  
21 metrics. The performance metrics are based on the safety audit conducted in the year  
22 of the cost recovery filing. For example, for the filing to be made in May 2022 for

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<sup>44</sup> Order No. 20-473 at 120-125.

1 the recovery of 2021 costs, the performance metrics used to apply the earnings test  
2 will be based on the 2022 safety audit.

3 Under the earning test, the greater the number of violations in the subsequent  
4 year’s audit, the lower the calculated ROE to get recovery. If the earnings test  
5 prevents recovery in a given year, capital investments may be recovered in a  
6 subsequent rate case. Table 3 below sets forth the earnings test to which capital costs  
7 and O&M expenses are subject.

8 **Table 3: WMVM Mechanism’s Earnings Test for First Incremental Spend**

<b>First increment of spend: \$6.645 million above \$30.0 million</b>		
\$6.645 million includes capital and O&M		
Applicable Earnings Test		
<b>Performance Metric</b>	<b>Number of Violations</b>	<b>Earnings Test</b>
Below Violation Level I	0 - 74	None
At or above Violation Level I, but below Violation Level II	75 - 149	Authorized ROE minus 100 basis points
At or above Violation Level II, but below Violation Level III	150 - 199	Authorized ROE minus 150 basis points
At or above Violation Level III	200+	Authorized ROE minus 200 basis points

9 **Q. Under the WMVM Mechanism, does the earnings test change for capital costs**  
10 **and O&M expenses above \$36.645 million?**

11 A. Yes. Capital costs and O&M expenses above \$36.645 million in the previous year are  
12 subject to a more relaxed earnings test, which is still scaled based on the number of  
13 violations as set forth in Table 4 below.

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**Table 4: WMVM Mechanism’s Earnings Test for Additional Spend**

<b>Additional spend: Amounts above \$36.645 million</b>		
Additional amount includes capital and O&M		
Applicable Earnings Test		
<b>Performance Metric</b>	<b>Number of Violations</b>	<b>Earnings Test</b>
Below Violation Level II	0 - 149	None
Level II or above and at least one violation in FHCA zone	150+	Authorized ROE minus 50 basis points

2 **Q. What are the changes PacifiCorp is proposing to the WMVM Mechanism?**

3 A. There are two category of changes that PacifiCorp is recommending. The first  
4 category relates to the wildfire mitigation component of the mechanism based on the  
5 enactment of SB 762.<sup>45</sup> The second category relates to the recovery of capital costs  
6 and O&M expenses under the mechanism. The Company proposes that both  
7 categories of changes take effect for the costs incurred under the mechanism in  
8 calendar year 2022 for which the Company will request recovery of in May 2023.

9 **Q. Please explain the proposed change to the mechanism as it relates to SB 762.**

10 A. On July 19, 2021, Governor Brown signed SB 762 into law. My understanding is that  
11 SB 762 requires electric utilities to file with the Commission risk-based wildfire  
12 protection plans that include a means for mitigating wildfire risk, balancing costs with  
13 the resulting reduction of risk, and preventive actions and programs to minimize risk  
14 of utility facilities causing a wildfire. Additionally, SB 762 Section 3(8) states:

15 All reasonable operating costs incurred by, and prudent investments  
16 made by, a public utility to develop, implement or operate a wildfire  
17 protection plan under this section are recoverable in the rates of the  
18 public utility from all customers through a filing under ORS 757.210 to  
19 757.220. The commission shall establish an automatic adjustment

<sup>45</sup> Chapter 592, 2021 Laws, SB 762.

1 clause, as defined in ORS 757.210, or another method to allow timely  
2 recovery of the costs.

3 SB 762 allows for electric utilities to request recovery of the costs associated with a  
4 wildfire protection plan through an automatic adjustment clause or another method to  
5 allow for timely recovery.

6 Under SB 762, PacifiCorp filed its wildfire protection plan with the  
7 Commission on December 30, 2021, in docket UM 2207.<sup>46</sup> Further, on January 5,  
8 2022, the Company filed an application for deferral accounting for 2022 costs  
9 associated with the wildfire protection plan.<sup>47</sup> PacifiCorp will also file in the second  
10 quarter of 2022 an application for approval of an automatic adjustment clause for  
11 costs incurred beginning in 2022 related to the implementation of its wildfire  
12 protection plan. If the automatic adjustment clause is approved, the Company would  
13 seek to recover the deferred 2022 costs related to its wildfire protection plan through  
14 the automatic adjustment clause.

15 Because the Company will be requesting an automatic adjustment clause for  
16 recovery of costs associated with its wildfire protection plan, the wildfire mitigation  
17 component of the WMVM Mechanism becomes redundant for those costs incurred  
18 beginning in 2022. Thus, PacifiCorp recommends that recovery of wildfire  
19 protection plan capital costs and O&M expenses be removed from the WMVM  
20 Mechanism beginning for costs incurred in 2022.

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<sup>46</sup> *In the Matter of PacifiCorp, dba Pacific Power, Wildfire Protection Plan*, Docket No. UM 2207, PacifiCorp Wildfire Protection Plan (Dec. 30, 2021).

<sup>47</sup> *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Operating Costs and Capital Investments Made to Implement and Operate PacifiCorp's Oregon Wildfire Protection Plan*, Docket No. UM 2221, Application filed Jan. 5, 2022.

1 **Q. Why is the Company proposing to remove the recovery of the costs associated**  
2 **with its wildfire protection plan from an already Commission-approved recovery**  
3 **mechanism?**

4 A. As I noted above, SB 762 provides for “[a]ll reasonable operating costs incurred by,  
5 and prudent investments made by, a public utility to develop, implement or operate a  
6 wildfire protection plan under this section are recoverable in the rates.”<sup>48</sup> While I am  
7 not an attorney, the language of SB 762 provides for the recovery of all costs to  
8 implement a wildfire protection plan and does not restrict the recovery of a utility’s  
9 costs to implement its plan other than providing that operating expenses be reasonable  
10 and capital investments prudent. However, if the Company’s wildfire protection plan  
11 operating expenses and capital costs were to be recovered through the WMVM  
12 Mechanism, they would be subjected to the earnings test contrary to SB 762 and  
13 make recovery of all costs dependent upon the number of vegetation management  
14 violations per a Staff audit report.

15 In recognizing the wildfire threat is of the utmost concern to Oregon, in Order  
16 20-473, the Commission approved a performance-based recovery mechanism to allow  
17 for the recovery of the Company’s wildfire mitigation and vegetation management  
18 efforts. After the Commission’s Order was issued, the State Legislature took action to  
19 address the wildfire threat Oregonians are facing and enacted a law that in part  
20 requires a utility to submit a formal wildfire protection plan; the Commission to  
21 approve the plan or approve the plan with conditions; and the Commission to  
22 establish an automatic adjustment clause or other method for the timely recovery of

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<sup>48</sup> SB 762, Section 3(8). (emphasis added)

1 all costs related to developing, implementing, or operating a wildfire protection plan.  
2 The WMVM Mechanism, which was based on the mitigation efforts described in the  
3 Company's 2021 Rate Case, does not allow for the timely recovery of all prudent and  
4 reasonable costs related to the Company's wildfire protection plan that the  
5 Commission is considering in docket UM 2207. By removing recovery of the  
6 wildfire protection plan costs from the mechanism, the Company can pursue an  
7 automatic adjustment clause to timely recover all prudent and reasonable costs  
8 associated with the capital-intensive implementation of the wildfire protection plan as  
9 contemplated by SB 762.

10 In signing SB 762, Governor Brown stated that "we still have a lot of work  
11 ahead of us to implement this bill."<sup>49</sup> She added that "we are laying the roadmap and  
12 devoting the resources to transform our approach to meet the challenges of this new  
13 era of wildfire" and SB 762 "exemplifies the proposition that by working together, we  
14 can create a safer, stronger, and more fire resilient Oregon."<sup>50</sup> Part of the roadmap set  
15 forth in SB 762 is preparation and approval of utilities' wildfire protection plans, the  
16 implementation of those plans, and the recovery of prudent capital costs and  
17 reasonable O&M expenses related to those plans. Removing recovery of wildfire  
18 protection plan costs from the WMVM Mechanism and allowing recovery of those  
19 costs through the to-be-filed automatic adjustment clause will better position the  
20 Company to meet the challenges of this new era of wildfire.

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<sup>49</sup> State of Oregon Press Release, "Governor Kate Brown Signs Bill to Modernize And Improve Wildfire Preparedness" (July 30, 2021) See, <https://www.oregon.gov/newsroom/Pages/NewsDetail.aspx?newsid=64182>

<sup>50</sup> *Id.*

1 **Q. What changes is the Company proposing to the recovery of costs under the**  
2 **WMVM Mechanism?**

3 A. The Company is proposing four modifications to the WMVM Mechanism:

- 4 1. Modification of the violation criteria for the level of violations;
- 5 2. Modification of the Safety Staff audit to verifiable violations on lines trimmed  
6 within two years;
- 7 3. Modification of the basis point penalty to a sharing percentage; and
- 8 4. Full recovery of costs due to inflation and new regulatory mandates.

9 These proposed modifications are further discussed by Mr. Berreth in his  
10 direct testimony.

11 **Q. Why is PacifiCorp proposing these changes to the WMVM Mechanism?**

12 A. The WMVM Mechanism is an important cost recovery mechanism for the Company  
13 to be able to recover the costs related to vegetation management. In approving the  
14 WMVM Mechanism, the Commission agreed finding that:

15 ... in an environment where wildfire risk mitigation is of utmost  
16 concern to our state, we find that the recovery of the incremental  
17 costs of vegetation management and wildfire mitigation between  
18 rate cases will ensure the company has both the obligation and the  
19 incentive to complete those investments and improve its vegetation  
20 management practices in an appropriate timeframe. We find that  
21 annual recovery of prudently incurred costs for vegetation  
22 management and wildfire mitigation, tied to demonstrated  
23 improvements to the company's vegetation management practices,  
24 appropriately matches the costs borne by and benefits received by  
25 ratepayers. Accordingly, we find that the annual deferral of costs  
26 within the mechanism is authorized under ORS 757.259(2)(e).<sup>51</sup>

27 However, as approved, the WMVM Mechanism does not allow the Company a fair  
28 opportunity to recover prudently incurred costs. Specifically, it does not balance the

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<sup>51</sup> Order 20-473 at 120. (footnote omitted)

1 obligation and incentive regarding vegetation management practices. In fact, the  
2 mechanism provides the perverse incentive for the Company to overspend on O&M  
3 related to vegetation management instead of strategically incurring O&M in a manner  
4 that decreases violations in a cost-conscious manner for customers. Under the current  
5 mechanism, the Company is incented to spend the minimum or maximum amounts to  
6 receive recovery, which does not make economic sense and would negatively impact  
7 customers. For example, to ensure recovery of its prudent and reasonable costs,  
8 PacifiCorp could spend \$100 million on vegetation management, while the number of  
9 violations would decrease, rates would drastically increase. The Company is  
10 proposing revisions to the mechanism to allow it to engage in a methodological spend  
11 over the course of several years that allows for the fair recovery of its costs.

12 **Q. Will PacifiCorp's modifications allow for a fair opportunity to recover prudent**  
13 **costs under the WMVM Mechanism?**

14 A. Yes. PacifiCorp's proposed modifications will better balance the obligation and  
15 incentive related to vegetation management practices. The Company is proposing to  
16 remove certain costs that are outside the Company's control from the application to  
17 the earnings test, such as costs related to changes to the Commission's vegetation  
18 management rules and increasing costs of labor and materials. PacifiCorp is also  
19 recommending changes to the violation criteria to align it better with other Oregon  
20 electric utilities and modifying the basis point penalty to a sharing percentage. The  
21 changes emphasize a proper incentive regarding vegetation management activities  
22 under the mechanism.



1                   **VIII. VOLUNTARY RENEWABLE ENERGY TARIFF**

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

3   A. In this section of my testimony, I discuss the Company’s proposed VRET, which the  
4   Company has named the Accelerated Commitment Tariff or the ACT, Schedule 273.

5   **Q. What is a VRET?**

6   A. A VRET is generally a utility offering that allows nonresidential customers to  
7   voluntarily elect to pay a premium rate to obtain service from a renewable energy  
8   resource, and have the environmental attributes retired on their behalf. VRETs  
9   provide nonresidential customers additional choices to support renewable energy  
10   development beyond what a utility has already planned.

11   **Q. Why is PacifiCorp proposing the ACT, which is a VRET, at this time?**

12   A. PacifiCorp’s nonresidential customers are looking for a renewable energy offering  
13   from the Company beyond the purchase of unbundled RECs under the Company’s  
14   Schedule 272. The ACT will provide these customers a program that will allow them  
15   more flexibility to meet their renewable energy goals and support acceleration of  
16   adoption of renewable energy beyond the requirements of HB 2021 for  
17   decarbonization of the Company’s base electric supply.

18                   Furthermore, it is my understanding that under HB 2021, an electric utility is  
19   required to reduce greenhouse gas emissions below the baseline emissions levels by  
20   80 percent by 2030; 90 percent by 2035; and 100 percent by 2040. As I discussed  
21   earlier in my testimony, PacifiCorp is transitioning its generation resources to a non-  
22   emitting renewable energy mix and has made substantial progress. However, work  
23   lies ahead to meet the targets in HB 2021. The ACT will allow PacifiCorp to add

1 incremental renewable resources, beyond planned economic investments, in an  
2 expedited manner, accelerating state policy of decarbonization through the voluntary  
3 participation of the Company's participating customers while limiting impacts to all  
4 customers. Because the incremental cost of the bundled renewable resource would be  
5 borne by the participating customer, the ACT would serve to advance implementation  
6 of HB 2021 renewable energy targets while protecting non-participating customers.  
7 This reduces the Company's need for incremental resources to reach its HB 2021  
8 targets. Under the ACT, customers will be able to support near-term additionality by  
9 adding sufficient demand to bring new renewables to the grid that would not have  
10 come online otherwise.

11 **Q. Would approval of the ACT program provide protection to vulnerable**  
12 **populations within PacifiCorp's service territory?**

13 A. Yes. While the ACT program will only be available to the Company's nonresidential  
14 customers, it provides protection to PacifiCorp's more vulnerable customers by  
15 accelerating PacifiCorp's decarbonization through resources paid for entirely by  
16 participating customers in the ACT program. The ACT program accelerates  
17 PacifiCorp's decarbonization goals by adding non-emitting resources to the  
18 Company's system without spreading the incremental cost to all customers, thereby  
19 reducing the impact of Oregon's energy goals on residential customers, including  
20 vulnerable populations. While the associated RECs are retired for the participating  
21 customer, meeting demand through non-emitting resources reduces emissions at no  
22 incremental cost to PacifiCorp's other customers. Further, if there is a circumstance  
23 where the length of the renewable resource obligation is less than the life of the

1 resource or term of the power purchase agreement, PacifiCorp's nonparticipating  
2 customers will benefit from the remaining production through energy from the non-  
3 emitting resource that has either been paid completely by a participating customer or  
4 has been substantially bought down.

5 **Q. Please describe the structure of PacifiCorp's proposed ACT program.**

6 A. Under the tariff, PacifiCorp will purchase bundled renewable energy resources and  
7 the corresponding RECs that meet the customer's need. Under the ACT, the  
8 participating customer will be responsible for the cost of the bundled energy  
9 renewable resource and as a result, costs of the resource are not shifted to non-  
10 subscribing customers. Further, participating customers must continue to take service  
11 under, and pay all components of, its applicable rate and all supplemental schedules  
12 and riders as determined for each delivery point. Direct access service customers are  
13 not eligible for the program. See Mr. Anderson's testimony for further details of the  
14 ACT and how it complies with the eight conditions set forth in Commission  
15 Order 21-091.<sup>52</sup>

## 16 **IX. TRANSITION ADJUSTMENT MECHANISM AND POWER COST**

### 17 **ADJUSTMENT MECHANISM**

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

19 A. In this section of my testimony, I discuss the Company's proposed changes to the  
20 TAM and PCAM.

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<sup>52</sup> *In the Matter of Portland General Electric Company, Investigation into Proposed Green Tariff*, Docket No. UM 1953, Order No. 21-091 (Mar. 29, 2021); Order No. 21-096 (Mar. 30, 2021), correcting Order No. 21-091.

1 **Q. What are the TAM and PCAM?**

2 A. The TAM forecasts a level of NPC for the following calendar year, which is  
3 recovered through Schedule 201. The PCAM, which is filed in the year following the  
4 TAM test year, allows for an opportunity for recovery or return of un-forecasted  
5 deviations in NPC if certain thresholds are met. Mr. Wilding further describes these  
6 mechanisms in his testimony.

7 **Q. What changes is PacifiCorp proposing to the TAM and PCAM?**

8 A. With respect to the TAM, PacifiCorp is proposing that an update during the rate year  
9 be performed, and a revision to the TAM Guidelines to allow more accurate  
10 hydrologic data into the NPC forecast. As to the PCAM, the Company is proposing  
11 to (1) adjust the deadbands to be symmetrical and lower the upper deadband from \$30  
12 million to \$15 million; (2) set the earnings test to PacifiCorp's authorized  
13 ROE; and (3) allow for the recovery of extraordinary, meaningful, and unpredictable  
14 events to be outside the deadbands, sharing bands, and earnings test.

15 **Q. Why is PacifiCorp proposing to change the TAM at this time?**

16 A. The Commission has noted in the TAM that "the accuracy of forecasts is of  
17 significant importance to setting fair and reasonable rates."<sup>53</sup> The Commission  
18 concludes that its "goal is to achieve an accurate forecast of PacifiCorp's [NPC] for  
19 the upcoming year."<sup>54</sup> As explained by Mr. Wilding, the modest changes to the TAM  
20 would increase accuracy by using the latest hydrologic information, allow the  
21 Company to incorporate the latest information and costs that are necessary to meet

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<sup>53</sup> *In the matter of PacifiCorp, dba Pacific Power 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 2-3 (Dec. 20, 2016).

<sup>54</sup> *Id.*

1 PacifiCorp’s resource adequacy requirements for the Western Power Pool’s Western  
2 Resource Adequacy Program.

3 **Q. Why is PacifiCorp proposing changes to the PCAM?**

4 A. In the 2021 Rate Case, PacifiCorp proposed significant changes to the PCAM  
5 mechanism.<sup>55</sup> The Commission found that “PacifiCorp has not demonstrated a  
6 fundamental change in the risk balance between customers and the company that  
7 occurs with its power costs.”<sup>56</sup> The loss of dispatchable generation across the west  
8 has fundamentally altered the risk balance on power costs. Through Mr. Wilding’s  
9 testimony, the Company presents evidence on the shifting risk balance that is  
10 currently occurring in the PCAM and proposes modest changes to help remedy these  
11 issues.

12 **X. INTRODUCTION OF COMPANY WITNESSES**

13 **Q How is PacifiCorp presenting this case?**

14 A. PacifiCorp is presenting the following direct testimony in support of its rate case  
15 filing:

- 16 • In Exhibit PAC/200, Nikki L. Kobliha, PacifiCorp’s Chief Financial Officer, will  
17 provide the Company’s overall cost of capital recommendation for the Company,  
18 including a capital structure to maximize value and minimize risk and the current  
19 cost of debt. Ms. Kobliha also addresses pension settlement accounting.
- 20 • In Exhibit PAC/300, Ann E. Bulkley, Principal at The Brattle Group, provides a  
21 comparison of PacifiCorp’s business and financial risk compared to peer utilities,  
22 recommends a cost of equity, and provides supporting analyses.

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<sup>55</sup> Docket No. UE 374, Exhibit PAC/500, Wilding Direct.

<sup>56</sup> Order 20-473 at 129-130.

- 1           • In Exhibit PAC/400, Michael G. Wilding, the Company’s Vice President of Energy  
2           Supply Management, addresses proposed changes to the Company’s Transition  
3           Adjustment Mechanism and Power Cost Adjustment Mechanism.
- 4           • In Exhibit PAC/500, Timothy J. Hemstreet, the Company’s Managing Director of  
5           Renewable Energy and Business Development, provides an update on the TB Flats  
6           Wind Project.
- 7           • In Exhibit PAC/600, Richard A. Vail, PacifiCorp’s Vice President of Transmission  
8           Services, discusses the Goshen to Sugarmill to Rigby 161 kilovolt (kV) and  
9           Jordanelle to Midway 138kV transmission lines.
- 10          • In Exhibit PAC/700, Allen Berreth, the Company’s Vice President of Transmission  
11          and Distribution Operations, discusses wildfire risk and the Company’s incremental  
12          investments in wildfire mitigation, and vegetation management.
- 13          • In Exhibit PAC/800, Erik Anderson, discusses the Company’s proposed ACT  
14          program.
- 15          • In Exhibit PAC/900, Kenneth Lee Elder, discusses the Company’s load forecast for  
16          the test year.
- 17          • In Exhibit PAC/1000, Sherona L Cheung, PacifiCorp’s Revenue Requirement  
18          Manager, summarizes the overall test year revenue requirement, pro forma  
19          adjustments, and the rate base calculation methodology.
- 20          • In Exhibit PAC/1100, Robert M. Meredith, Director of Pricing and Tariff Policy,  
21          provides PacifiCorp’s cost allocation and rate design, and discusses how the  
22          proposed tariff changes recover the proposed 2023 revenue requirement to achieve  
23          fair, just, and reasonable prices for customers.

1 **XI. CONCLUSION**

2 **Q. Please summarize your recommendations to the Commission.**

3 A. I recommend the Commission approve the proposals described in Section II of my  
4 testimony, including:

- 5 • Authorizing an overall increase of \$84.4 million or approximately 6.8 percent;
- 6 • Approving a total rate base of approximately \$4.2 billion, as discussed in the  
7 testimony of various witnesses in this rate case;
- 8 • Approve an overall cost of capital of 7.21 percent, which is comprised of a capital  
9 structure of 52.25 percent equity, 47.74 percent long-term debt, and 0.01 percent  
10 preferred stock and a ROE of 9.8 percent;
- 11 • Approving the proposed updates to the Oregon depreciable lives and/or revisions  
12 to the Exit Orders for coal-fired resources approved in the 2021 Rate Case as  
13 described in my testimony;
- 14 • Approving the proposed revisions to the WMVM Mechanism;
- 15 • Approving PacifiCorp's proposed VRET, the ACT, Schedule 273; and
- 16 • Approving the proposed modifications to the TAM and PCAM.

17 **Q. Does this conclude your direct testimony?**

18 A. Yes.

Docket No. UE 399  
Exhibit PAC/101  
Witness: Joelle R. Steward

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

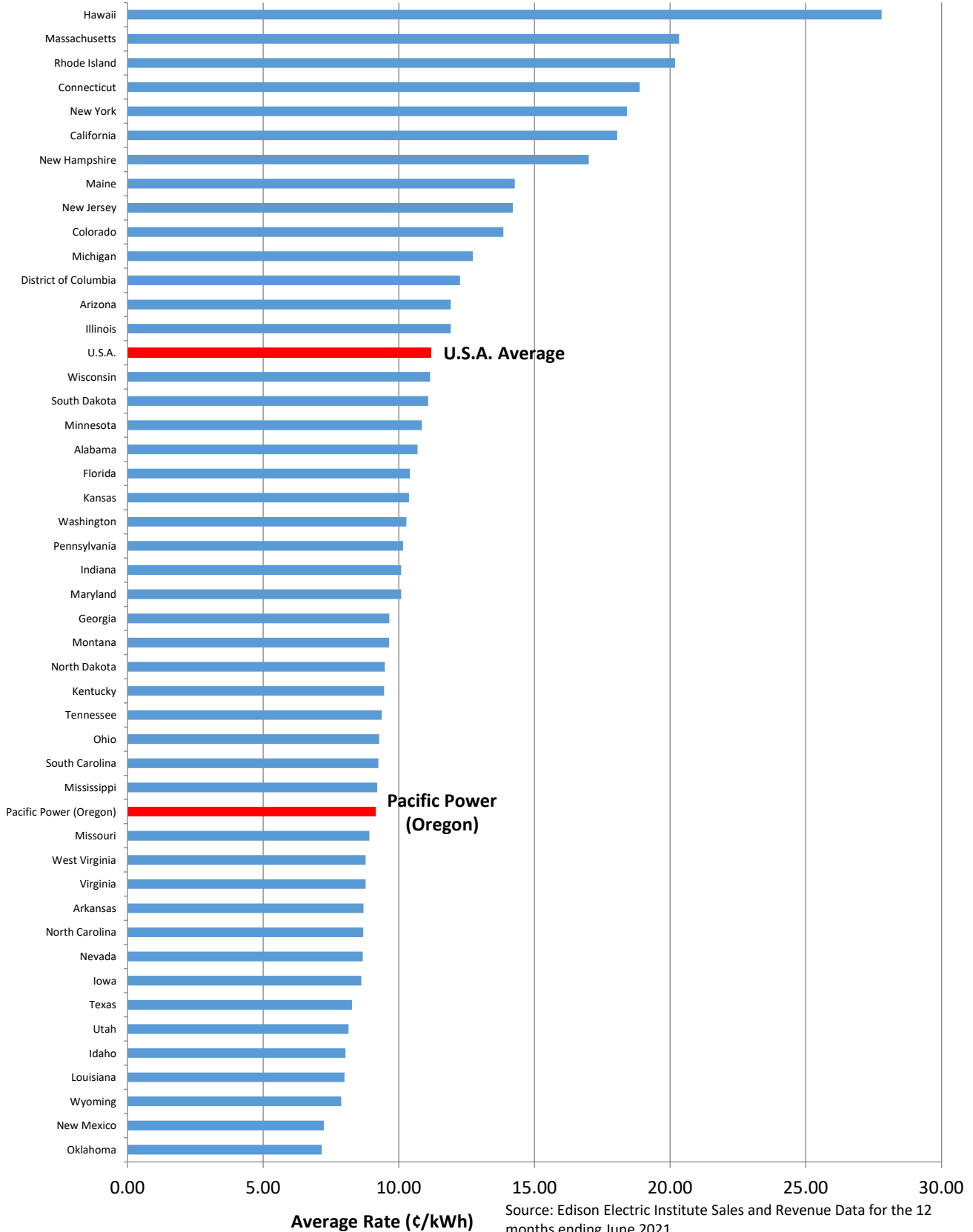
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**Exhibit Accompanying Direct Testimony of Joelle R. Steward  
PacifiCorp's Oregon Rates Compared to National Averages**

**March 2022**



# Total Retail Average Rates



**REDACTED**  
Docket No. UE 399  
Exhibit PAC/200  
Witness: Nikki L. Kobliha

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**REDACTED**  
**Direct Testimony of Nikki L. Kobliha**

**March 2022**

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## ATTACHED EXHIBITS

Exhibit PAC/201—Pro forma Cost of Long-Term Debt

Exhibit PAC/202—Arizona Public Service Company October 2008 Letter to the Arizona  
Corporation Commission

Exhibit PAC/203—New Debt Issue Spreads

Confidential Exhibit PAC/204—S&P Ratings Direct November 19, 2013

Exhibit PAC/205—Indicative Forward Pollution Control Revenue Bonds Variable Rates

Exhibit PAC/206—Cost of Preferred Stock

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**I. INTRODUCTION AND QUALIFICATIONS**

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

A. My name is Nikki L. Kobliha and my business address is 825 NE Multnomah Street, Suite 1900, Portland, Oregon 97232. I am currently employed as Vice President, Chief Financial Officer and Treasurer for PacifiCorp.

**Q. Please describe your education and professional experience.**

A. I received a Bachelor of Business Administration with a concentration in Accounting from the University of Portland in 1994. I became a Certified Public Accountant in 1996. I joined PacifiCorp in 1997 and have taken on roles of increasing responsibility before being appointed Chief Financial Officer in 2015. I am responsible for all aspects of PacifiCorp’s finance, accounting, income tax, internal audit, Securities and Exchange Commission reporting, treasury, credit risk management, pension, and other investment management activities.

**II. SUMMARY AND PURPOSE OF TESTIMONY**

**Q. Please summarize the purpose of your testimony.**

A. My testimony supports PacifiCorp’s overall cost of capital recommendation and addresses pension settlement accounting.

**Q. What is the purpose of each of the items summarized above?**

A. Regarding the overall cost of capital recommendation, I sponsor the Company’s proposed capital structure with a common equity level of 52.25 percent and provide evidence demonstrating why that level is appropriate and benefits customers.

1 I explain why the 50/50 capital structure ordered in the last general rate  
2 case, docket UE 374 (2021 Rate Case)<sup>1</sup> is not a balanced outcome, and how the  
3 recommended common equity ratio is required to maintain PacifiCorp's current  
4 credit ratings. Strong credit ratings provide for a more competitive cost of debt and  
5 overall cost of capital and facilitate continued access by the Company to the capital  
6 markets over the long term, which includes times when the capital markets are  
7 stable and there is ample liquidity, but also when the capital markets are unstable  
8 and liquidity is tight and expensive. The recommended capital structure enables the  
9 Company's continued investment in infrastructure to provide safe and reliable  
10 service from clean energy resources at reasonable costs. I also support PacifiCorp's  
11 proposed cost of long-term debt of 4.38 percent and cost of preferred stock of  
12 6.75 percent.

13 Regarding pension settlement accounting, I will explain the Company's  
14 recent pension settlement loss related activities and treatment thereof in this filing.

15 **Q. What overall cost of capital do you recommend for PacifiCorp?**

16 A. PacifiCorp proposes an overall cost of capital of 7.21 percent. This cost includes  
17 the return on equity recommendation of 9.80 percent as supported by the direct  
18 testimony of Ms. Ann E. Bulkley and the capital structure and costs set forth in  
19 Table 1.

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<sup>1</sup> *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).*

1

**Table 1: Overall Cost of Capital**

<b>Component</b>	<b>\$m</b>	<b>% of Total</b>	<b>Cost %</b>	<b>Wtd Ave Cost %</b>
Long-Term Debt	\$9,989	47.74 %	4.38 %	2.09 %
Preferred Stock	2	0.01 %	6.75 %	— %
Common Stock Equity	<u>10,933</u>	<u>52.25 %</u>	9.80 %	<u>5.12 %</u>
	\$20,924	100.00 %		7.21 %

2 **Q. What time period does your analysis cover?**

3 A. The capital structure for the Company is measured over the calendar year 2023 test  
 4 period (Test Period) used in this proceeding using an average of the five quarter-  
 5 ending balances spanning the 12-month period ending December 31, 2023, based  
 6 on known and measurable changes through December 31, 2023. Similarly, the  
 7 costs of the long-term debt and preferred stock are an average of the costs measured  
 8 for each of the five quarter-ending balances spanning the Test Period, using the  
 9 Company’s actual costs adjusted for known and measurable changes through  
 10 December 31, 2023.

11 **III. DISCUSSION OF RECENTLY ORDERED CAPITAL STRUCTURE**

12 **Q. As indicated in the 2021 Rate Case order the Commission found “...a more**  
 13 **balanced capital structure serves to reduce the cost of equity to customers,**  
 14 **without jeopardizing the financial integrity of the company. We find that a**  
 15 **50 percent equity achieves that balance.”<sup>2</sup> Do you agree a 50.00 percent**  
 16 **common equity level results in a balanced outcome at this time?**

17 A. No, because a 50.00 percent common equity level does not consider the significant  
 18 capital growth cycle the Company is in as it expands its renewable portfolio and  
 19 associated transmission. The need for low-cost debt financing is critical at this time

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<sup>2</sup> Order No. 20-473 at 25.

1 as the Company will be accessing the capital markets numerous times over the next  
 2 several years. The 52.25 percent proposed common equity level will enable the  
 3 Company to maintain its credit ratings and issue debt at favorable rates, even if  
 4 market conditions become unstable, keeping costs low for customers. The last  
 5 several years have demonstrated that a five-quarter average common equity level  
 6 near the proposed 52.25 percent common equity level is needed in order to maintain  
 7 the Company's financial integrity. The Company's projected average percentage  
 8 capital structures in 2022 and 2023 continue at levels consistent with the past, all of  
 9 which are in excess of the 50.00 percent capital structure ordered in the 2021 Rate  
 10 Case.

11 The referenced capital structures are found in Table 2 below.

12 **Table 2: Forecast and Actual Capital Structures**

	<b>Dec 31, 2023 Forecast*</b>	<b>Dec 31, 2022 Forecast*</b>	<b>Dec 31, 2021 Actual*</b>	<b>Dec 31, 2020 Actual*</b>	<b>Dec 31, 2019 Actual*</b>	<b>2021 Rate Case Capital Structure</b>
Long-Term Debt	47.74%	46.95%	47.69%	48.49%	48.36%	49.99%
Preferred Stock	0.01%	0.01%	0.01%	0.01%	0.02%	0.01%
Common Equity	52.25%	53.04%	52.30%	51.50%	51.62%	50.00%
Totals	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

\* Five quarter-end average % Capital Structure calculated for trailing 12 month period ending December 31, 2023

13 If PacifiCorp were to re-balance its capital structure to reflect the 50.00  
 14 percent common equity component ordered by the Commission, PacifiCorp would  
 15 issue approximately \$1.8 billion of debt and pay dividends totaling \$1.9 billion to  
 16 its parent company Berkshire Hathaway Energy Company (BHE) in 2022. The  
 17 increased debt would reduce PacifiCorp's Cash from Operations pre-Working  
 18 Capital (CFO pre-W/C) to Debt ratio to [REDACTED] and jeopardize its financial  
 19 integrity [REDACTED]

1 [REDACTED], which is inconsistent with its  
2 current financial profile.

3 Moody's recently issued credit opinion for PacifiCorp notes that:

4 The stable outlook incorporates our expectation that PacifiCorp  
5 will continue to receive reasonable regulatory treatment, and that  
6 funding requirements will be financed in a manner consistent with  
7 management's commitment to maintain a healthy financial profile.

8 ...The ratings could be downgraded if PacifiCorp's capital  
9 expenditures are funded in a manner inconsistent with its current  
10 financial profile, or if adverse regulatory rulings lower its credit  
11 metrics, as demonstrated for example, by a ratio of CFO pre-WC  
12 to debt remaining below 19%.<sup>3</sup>

13 Furthermore, the Commission's ordered 4.774 percent cost of long-term  
14 debt was based on PacifiCorp maintaining its current A rating and as noted above,  
15 moving to a 50.00 percent common equity component would result in credit metrics  
16 that do not support an A rating and would most likely result in a ratings downgrade.  
17 This was not a balanced outcome as the Commission provided customers with the  
18 benefit of the lower capital structure but did not adjust rates for the higher cost of  
19 debt that would occur with a lower credit rating, and disregarded the financial risk  
20 to PacifiCorp from having a lower credit rating in the midst of a significant and  
21 sustained capital build cycle.

22 As provided in Table 3 below, in periods of significant and sustained capital  
23 spending the 19.0 percent CFO pre-W/C to debt ratio was not maintained at equity  
24 levels in excess of 50.00 percent indicating a higher level is needed during this  
25 period.

---

<sup>3</sup> Moody's Credit Opinion, *PacifiCorp Update to Credit Analysis* (June 30, 2021), at 2.



**Table 3: Comparison of Capital Spend and Moody’s CFO pre-W/C to Debt**

**Ratio**

	2017	2018	2019	2020	2021	2022	2023	2024
	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast
CAPEX (\$m)	\$769	\$1,257	\$2,175	\$2,540	\$1,513	\$2,001	\$3,317	\$2,501
CFO pre-W/C to Debt	23.0%	21.9%	18.4%	16.7%	██████	██████	██████	██████
Equity %	51.5%	52.1%	51.6%	51.5%	52.3%	53.0%	52.3%	52.5%

\*Forecast metric

The significant and sustained capital spending is required to meet the energy policy and wildfire mitigation objectives of the state of Oregon and as a result of PacifiCorp’s 2021 Integrated Resource Plan (IRP).<sup>4</sup>

**Q. In the 2021 Rate Case Order, the Commission noted “The company did not address, however, how the savings associated with the lower cost of debt compared to the higher costs of an increased equity ratio.”<sup>5</sup> Please explain how much the cost of debt would need to increase to offset the higher cost of equity at the Company’s proposed capital structure.**

**A.** The overall cost of capital using the Company’s proposed 52.25 percent common equity is 7.21 percent while use of a Commission ordered hypothetical 50.00 percent common equity results in a cost of capital of 7.09 percent. Later in my testimony I demonstrate the Company’s cost of debt would be 4.84 percent had the Company not had its current single A rating, or a 46 basis point cost of debt increase. Using the 46 basis point higher debt rate with a Commission ordered hypothetical capital structure would have increased the cost of capital to 7.32 percent. The thicker equity needed to maintain the Company’s credit rating

<sup>4</sup> *In the Matter of PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan*, Docket No. LC 77.

<sup>5</sup> Order No. 20-473 at 25.

1 has kept the overall cost of capital low. An increase of 24 basis points in the  
 2 Company’s cost of debt is the breakeven point between the 52.25 percent proposed  
 3 capital structure and a 50.00 percent Commission ordered hypothetical capital  
 4 structure, where the cost of capital in both cases would be 7.21 percent. See Table 4  
 5 below.

6 **Table 4: Cost of Capital Comparison**

	<b>Proposed</b>	<b>Hypothetical Capital Structure</b>	<b>BBB rated Debt</b>	<b>Breakeven Cost of Capital</b>
Cost of Debt	4.38	4.38	4.84	4.62
Percent Common	52.25	50.00	50.00	50.00
Cost of Capital	7.21	7.09	7.32	7.21

7 That 24 basis point cost of debt increase can easily occur through normal week-on-  
 8 week volatility and does not necessarily require severe market instability. A strong  
 9 credit rating helps insulate the Company from those types of movements and  
 10 enables continued access to the capital markets in nearly all situations. A strong  
 11 credit rating can also be thought of as a type of insurance against market volatility  
 12 and instability. Setting rates using a 12 basis point higher cost of capital  
 13 (7.21 percent compared to the 7.09 percent), an estimated \$5.0 million revenue  
 14 requirement impact, is a reasonable price to pay considering the 46 basis points  
 15 savings the Company realized from being single A rated, and to avoid what can be  
 16 severe cost of debt increases when market volatility or instability occurs,  
 17 particularly with the level of debt the Company will be issuing in the next several  
 18 years as the Company works to achieve Oregon’s energy policy objectives.

1 **Q. In the 2021 Rate Case the Commission points to other Oregon utilities having a**  
2 **50/50 capital structure. Is that a fair comparison and justification for**  
3 **PacifiCorp to have a 50/50 capital structure?**

4 A. No. There are a number of factors that support why a one size fits all capital  
5 structure is not appropriate. First, while Portland General Electric Company is  
6 similarly rated to PacifiCorp, they have a lower credit metric requirement making it  
7 easier for them to maintain an A rating. Second, Avista is lower rated resulting in  
8 significantly lower credit metric requirements. Third, the aforementioned utilities  
9 have different capital expenditure programs driving different financing  
10 requirements and the need to access capital markets. This can be seen when  
11 comparing the ratio of capital expenditures (CAPEX) to cash from operations  
12 (CFO) in Table 5. The Company's largely higher ratio indicates a greater need for  
13 debt and equity funding to pay for prudently incurred CAPEX on a least-cost, least-  
14 risk basis, including new renewable resources identified in PacifiCorp's 2021 IRP  
15 action plan and wildfire mitigation costs.

1

**Table 5: Comparison of Oregon utilities' ratio of CAPEX to CFO**

<b>PGE</b> (\$,millions)	<b>2019</b> <b>Actual</b>	<b>2020</b> <b>Actual</b>	<b>2021</b> <b>Forecast</b>	<b>2022</b> <b>Forecast</b>	<b>2023</b> <b>Forecast</b>
CAPEX	\$ 606	\$ 784	\$ 655	\$ 550	\$ 550
CFO <sup>1</sup>	\$ 546	\$ 567	\$ 585	\$ 585	\$ 585
Ratio - CAPEX to CFO	1.1	1.4	1.1	0.9	0.9

<sup>1</sup> Forecast CFO is based on the average of 2017 through 2020  
Source 2019 and 2020 SEC Form 10-K

<b>Avista</b> (\$,millions)	<b>2019</b> <b>Actual</b>	<b>2020</b> <b>Actual</b>	<b>2021</b> <b>Forecast</b>	<b>2022</b> <b>Forecast</b>	<b>2023</b> <b>Forecast</b>
CAPEX	\$ 443	\$ 404	\$ 415	\$ 405	\$ 405
CFO <sup>1</sup>	\$ 398	\$ 331	\$ 375	\$ 375	\$ 375
Ratio - CAPEX to CFO	1.1	1.2	1.1	1.1	1.1

<sup>1</sup> Forecast CFO is based on the average of 2017 through 2020  
Source 2019 and 2020 SEC Form 10-K

<b>PacifiCorp</b> (\$,millions)	<b>2019</b> <b>Actual</b>	<b>2020</b> <b>Actual</b>	<b>2021</b> <b>Actual</b>	<b>2022</b> <b>Forecast</b>	<b>2023</b> <b>Forecast</b>
CAPEX	\$ 2,175	\$ 2,540	\$ 1,513	\$ 2,001	\$ 3,317
CFO <sup>2</sup>	\$ 1,547	\$ 1,583	\$ 1,804	\$ 1,669	\$ 1,669
Ratio - CAPEX to CFO	1.4	1.6	0.8	1.2	2.0

<sup>2</sup> Forecast CFO is based on the average of 2017 through 2021

2 **Q. Does the Company agree that a 50/50 capital structure is the optimal capital**  
3 **structure for PacifiCorp and strikes a balance between the interest of**  
4 **customers and the interests of investors, particularly during its current build**  
5 **cycle?**

6 **A.** No. In an effort to maintain credit ratings and low-cost access to debt markets,  
7 during this significant and sustained capital build cycle, the Company believes the  
8 requested 52.25 percent common equity capital structure is the optimal capital  
9 structure at this time. The following quote from a finance textbook written by  
10 Roger Morin also supports the Company's current position:

11 The optimal capital structure...suggests that long-term  
12 achievement of a single A credit rating is in a utility  
13 company's and its ratepayers best interests. Debt leverage

1 targets should be set in the lower part of the range required to  
2 attain this optimal rating. If the company maintains its debt  
3 ratio close to the optimal range required for a single A bond  
4 rating, its overall cost of capital should be minimized.<sup>6</sup>

5 PacifiCorp currently has a Moody/Standard & Poor's (S&P) bond issuer credit  
6 rating of A3/A, which is considered a single A credit rating, and as suggested from  
7 the textbook will minimize its overall cost of capital.

8 **Q. Does a 50.00 percent common equity component allow for economic access to**  
9 **the capital market in uncertain economic times?**

10 A. No. Financial flexibility plays a key role in ensuring liquidity and allowing the  
11 Company to meet its funding needs. Higher leverage and a lower credit rating may  
12 result in the Company not having access or having to pay significantly more for  
13 liquidity. As Moody's states:

14 Utilities are among the largest debt issuers in the corporate universe  
15 and typically require consistent access to capital markets to assure  
16 adequate sources of funding and to maintain financial flexibility.  
17 During times of distress and when capital markets are exceedingly  
18 volatile and tight, liquidity becomes critically important because  
19 access to capital markets may be difficult.<sup>7</sup>

20 The Company's credit rating must be supported by its capital structure to allow for  
21 continuous access to capital even in unfavorable financial market conditions. Given  
22 the Company's significant and sustained capital spending, low average retail rates  
23 and the potential for uncertain economic times, a stronger balance sheet and higher  
24 common equity is warranted.

---

<sup>6</sup> Roger A. Morin, PhD, *New Regulatory Finance, Public Utilities Reports, Inc, Virginia* 2006, p.471.

<sup>7</sup> Moody's Sector Comment, *FAQ on credit implications of the coronavirus outbreak* (Mar. 26, 2020), at 1.

1 **IV. FINANCING OVERVIEW**

2 **Q. Please explain PacifiCorp's need for and sources of new capital.**

3 A. PacifiCorp requires capital to meet its customers' needs for new cost-effective,  
4 transmission and renewable generation, increased reliability, improved power  
5 delivery, and safe operations. PacifiCorp also needs new capital to fund long-term  
6 debt maturities.

7 As a result of the 2021 IRP, PacifiCorp expects to spend approximately  
8 \$6.0 billion (excluding equity allowance for funds used during construction) on  
9 renewable energy projects, related transmission, and carbon free generation through  
10 calendar year 2026 with \$2.8 billion being spent during 2022 and 2023. In addition  
11 to the \$2.8 billion, PacifiCorp expects to spend approximately \$290 million on  
12 wildfire mitigation during 2022 and 2023. This significant and sustained level of  
13 capital spending will require PacifiCorp to raise funds by issuing new long-term  
14 debt in the capital markets, retain earnings, and if needed, obtain new capital  
15 contributions from its parent company, BHE. This increase in renewable and  
16 carbon free generation and transmission capacity will support PacifiCorp's progress  
17 towards acquiring the new renewable resources identified in PacifiCorp's 2021 IRP  
18 action plan and ability to meet the energy policy objectives of the state of Oregon  
19 on a least-cost, least-risk basis.

20 **Q. How does PacifiCorp finance its electric utility operations?**

21 A. Generally, PacifiCorp finances its regulated utility operations using a mix of debt  
22 and common equity capital of approximately 48/52 percent, respectively. During  
23 periods of significant and sustained capital expenditures, as expected to continue

1 now through calendar year end 2023 and beyond for the potential new renewable  
2 and carbon free generation resources and associated transmission identified in  
3 PacifiCorp's 2021 IRP action plan, the Company will need to maintain an average  
4 common equity component in excess of 52.00 percent to maintain its credit rating  
5 and finance the debt component of the capital structure at the lowest reasonable cost  
6 to customers. Maintaining the Company's credit rating will provide more flexibility  
7 on the type and timing of debt financing, better access to capital markets, a more  
8 competitive cost of debt, and over the long-run, more stable credit ratings. All of  
9 these factors assist in financing expenditures like potential new renewable and  
10 carbon free generation resources and associated transmission identified in  
11 PacifiCorp's 2021 IRP action plan. In addition, PacifiCorp needs a greater common  
12 equity component to offset various adjustments that rating agencies make to the  
13 debt component of the Company's published financial statements. I discuss these  
14 adjustments in greater detail later in my testimony.

15 **Q. How does PacifiCorp determine the levels of common equity, debt, and**  
16 **preferred stock to include in its capital structure?**

17 A. As a regulated public utility, PacifiCorp has a duty and an obligation to provide  
18 safe, adequate, and reliable service to customers in its Oregon service area while  
19 prudently balancing cost and risk. Major capital expenditures are required in the  
20 near-term for new plant investment to fulfill its service obligation, including capital  
21 expenditures for new renewable and carbon free generation resources, new  
22 transmission, and wildfire mitigation. These capital investments also have  
23 associated operating and maintenance costs. As part of its annual business plan

1 process, PacifiCorp reviews all of its estimated cash inflows and outflows to  
2 determine the amount, timing, and type of new financing required to support these  
3 activities and provide for financial results and credit ratings that balance the cost of  
4 capital with continued access to the financial markets.

5 **Q. How does PacifiCorp manage its dividends to BHE?**

6 A. PacifiCorp benefits from its affiliation with BHE as there is no dividend  
7 requirement. Historically, PacifiCorp has paid dividends to BHE to manage the  
8 common equity component of the capital structure and keep the Company's overall  
9 cost of capital at a prudent level. In major and sustained capital investment periods,  
10 PacifiCorp is able to retain earnings to help finance capital investments and forgo  
11 paying dividends to BHE. For example, following BHE's acquisition of PacifiCorp  
12 in 2006, PacifiCorp managed the capital structure through the timing and amount of  
13 long-term debt issuances and capital contributions from BHE, while forgoing any  
14 common dividends for nearly five years. At other times, absent the payment of  
15 dividends, retention of earnings could cause the percentage of common equity to  
16 grow beyond the level necessary to support the current credit ratings. Accordingly,  
17 dividend payments can be necessary, in combination with debt issuances, to  
18 maintain the appropriate percentage of equity in PacifiCorp's capital structure. In  
19 2015, 2016 and 2017 PacifiCorp paid dividends of \$950 million, \$875 million and  
20 \$600 million, respectively, and only issued \$250 million in long-term debt, due to  
21 lower capital spend during this time period. The proposed capital structure in this  
22 case anticipates modest common dividend payments by PacifiCorp to BHE of



1 \$300 million in 2022 and \$250 million in 2023 and are needed to keep the common  
2 equity level at 52.25 percent.

3 **Q. What type of debt does PacifiCorp use in meeting its financing requirements?**

4 A. PacifiCorp has completed the majority of its recent long-term financing using  
5 secured first mortgage bonds issued under the Mortgage Indenture dated January 9,  
6 1989. Exhibit PAC/201, Pro Forma Cost of Long-Term Debt, shows that, over the  
7 Test Period, PacifiCorp is projected to have an average of approximately  
8 \$9.8 billion of first mortgage bonds outstanding, with an average cost of  
9 4.43 percent. Presently, all outstanding first mortgage bonds bear interest at fixed  
10 rates. Proceeds from the issuance of the first mortgage bonds (and other financing  
11 instruments) are used to finance the utility operation.

12 Another important source of financing in the past has been the tax-exempt  
13 financing associated with certain qualifying equipment at power generation plants.  
14 Under arrangements with local counties and other tax-exempt entities, these entities  
15 issue securities, PacifiCorp borrows the proceeds of these issuances and pledges its  
16 credit quality to repay the debt to take advantage of the tax-exempt status of the  
17 financing. During the 12 months ending December 31, 2023, PacifiCorp's tax-  
18 exempt portfolio is projected to be approximately \$185 million, with an average  
19 cost of 1.60 percent, including the cost of issuance and remarketing.

20 **A. Credit Ratings**

21 **Q. What are PacifiCorp's current credit ratings?**

22 A. PacifiCorp's current ratings are shown in Table 6.

1

**Table 6: PacifiCorp Credit Ratings**

	<b>Moody's</b>	<b>Standard &amp; Poor's</b>
Senior Secured Debt	A1	A+
Senior Unsecured Debt	A3	A
Outlook	Stable	Stable

2

**Q. How does the maintenance of PacifiCorp's current credit rating benefit customers?**

3

4

A. First, the credit rating of a utility has a direct impact on the price that a utility pays to attract the capital necessary to support its current and future operating needs.

5

6

Many institutional investors have fiduciary responsibilities to their clients and are typically not permitted to purchase non-investment grade (*i.e.*, rated below

7

8

Baa3/BBB-) securities or in some cases even securities rated below a single A

9

rating. A solid credit rating directly benefits customers by reducing the immediate

10

and future borrowing costs related to the financing needed to support regulatory

11

obligations.

12

Second, credit ratings are an estimate of the probability of default by the

13

issuer on each rated security. Lower ratings equate to higher risks and higher costs

14

of debt. The Great Recession of 2008–2009 provides a clear and compelling

15

example of the benefits of the Company's credit rating because PacifiCorp was able

16

to issue new long-term debt during the midst of the financial turmoil. Other lower-

17

rated utilities were shut out of the market and could not obtain new capital.

18

Third, PacifiCorp has a near constant need for short-term liquidity as well as

19

periodic long-term debt issuances. PacifiCorp pays significant amounts daily to

20

suppliers whom we count on to provide necessary goods and services such as fuel,

21

energy, construction services and inventory, and has an active long-term debt

1 portfolio that must be managed for interest payments and maturities. Being unable  
2 to access funds can risk the successful completion of necessary capital  
3 infrastructure projects and could impact system reliability, customer safety and the  
4 ability to meet Oregon's energy policy objectives for carbon free generation on a  
5 least-cost, least-risk basis. PacifiCorp's credit facilities may not have the capacity  
6 to cover these significant periodic uses of cash and not having access to the market  
7 would jeopardize the ability to issue lower rate debt.

8 PacifiCorp's creditworthiness, as reflected in its credit ratings, will strongly  
9 influence its ability to attract capital in the competitive markets and the resulting  
10 costs of that capital.

11 **Q. Can you provide an example of how the current ratings have benefited**  
12 **customers?**

13 A. Yes. One example is PacifiCorp's ability to significantly reduce its cost of long-  
14 term debt primarily through obtaining new financings at very attractive interest  
15 rates. The lower cost of debt benefits customers through a lower overall rate of  
16 return and lower revenue requirement.

17 To determine the savings realized from maintaining a higher credit rating, in  
18 Exhibit PAC/203 New Debt Issue Spreads, I compared the actual effective interest  
19 rate on the Company's existing as well as pro-forma and repriced long-term debt  
20 forecasted to be outstanding during the Test Period, which was issued since its  
21 acquisition by BHE in 2006, comprising 18 series of debt, to what the effective  
22 interest rate would have been with a BBB credit rating. The issuance spread of each  
23 issuance was changed to match what a BBB rated utility achieved at about the same

1 point in time that PacifiCorp issued the debt. The total result for the 18 series of  
 2 debt averaging \$8.9 billion over the test period, would have been an effective  
 3 average interest rate of approximately 4.74 percent or 52 basis points higher than  
 4 the actual effective interest rate. Combined with the existing pre-acquisition debt,  
 5 the resulting overall cost of long-term debt would increase to 4.84 percent if the  
 6 Company had a BBB rating. PacifiCorp is currently projecting an overall cost of  
 7 long-term debt of 4.38 percent, or 46 basis points lower than it might have  
 8 otherwise been under the scenario I described above.

9 Table 7 below shows the reduction in the Company’s cost of long-term debt  
 10 since 2010.

11 **Table 7: PacifiCorp’s Cost of Long-Term Debt**

	<b>Dec 2023</b>	<b>UE 374 Dec 2021</b>	<b>UE 263 Dec 2013</b>	<b>UE 246 Dec 2012</b>	<b>UE 217 Dec 2010</b>
Cost of Long-Term Debt	4.38%	4.77%	5.32%	5.37%	5.85%

12 PacifiCorp’s customers have benefited from a 147 basis points  
 13 (1.47 percent) reduction in the Company’s cost of long-term debt. The Company  
 14 estimates that this reduction in the average cost of debt since 2010 results in a  
 15 decrease of approximately \$31.0 million in the revenue requirement in the current  
 16 case. Customers have also benefited from the Company’s ability to negotiate lower  
 17 underwriting fees on long-term debt issuances through BHE’s global underwriting  
 18 fee position.

19 **Q. Are there other identifiable advantages to a favorable rating?**

20 A. Yes. Higher-rated companies have greater access to the long-term markets for  
 21 power purchases and sales. This access provides these companies with more

1 alternatives to meet the current and future load requirements of their customers.  
2 Additionally, a company with strong ratings will often avoid having to meet costly  
3 collateral requirements that are typically imposed on lower-rated companies when  
4 securing power in these markets.

5 In my opinion, maintaining the current single A rating provides the best  
6 balance between costs and continued access to the capital markets, which is  
7 necessary to fund capital projects for the benefit of customers.

8 **Q. Please provide examples where poor credit ratings hurt a utility's flexibility in**  
9 **the credit markets.**

10 A. During the Great Recession in 2008, Arizona Public Service Company (rated  
11 Baa2/BBB- at that time) filed a letter with the Arizona Corporation Commission in  
12 October 2008 stating that the commercial paper market was completely closed to it  
13 and it likely could not successfully issue long-term debt.<sup>8</sup>

14 Further, those issuers who could access the markets paid rates well above  
15 the levels that PacifiCorp was able to obtain. For example, PacifiCorp issued new  
16 10-year and 30-year long-term debt in January 2009 with 5.50 percent and  
17 6.00 percent coupon rates, respectively. Subsequently, Puget Sound Energy (rated  
18 Baa2/A- at that time) issued new seven-year debt at a credit spread over Treasuries  
19 of 480.3 basis points resulting in a 6.75 percent coupon.

20 **Q. Can regulatory actions or orders affect PacifiCorp's credit rating?**

21 A. Yes. Regulated utilities such as PacifiCorp are unique in that they cannot  
22 unilaterally set the price for their services. The financial integrity of a regulated

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<sup>8</sup> See Exhibit PAC/302.

1 utility is largely a result of the prudence of utility operations and the corresponding  
2 prices set by regulators. Rates are established by regulators to permit the utility to  
3 recover prudently incurred operating expenses and a reasonable opportunity to earn  
4 a fair return on the capital invested.

5 Rating agencies and investors have a keen understanding of the importance  
6 of regulatory outcomes. For example, S&P has opined on the correlation between  
7 regulatory outcomes and credit ratings, concluding:

8 Although not common, rate case outcomes can sometimes lead  
9 directly to a change in our opinion of creditworthiness. Often it's  
10 a case that takes on greater importance because of the issues being  
11 litigated. For example, in 2010, we downgraded Florida Power &  
12 Light and its affiliates following a Florida Public Service  
13 Commission rate ruling that attracted attention due to drastic  
14 changes to settled practices on rate case particulars like  
15 depreciation rates. More recently, in June 2016, we downgraded  
16 Central Hudson Electric & Gas due to our revised opinion of  
17 regulatory risk. While that reflected the company's own  
18 management of regulatory risk, it was prompted in part by other  
19 rate case decisions in New York that highlighted the overall risk in  
20 the state.<sup>9</sup>

21 As discussed in the testimony of Ms. Bulkley, Section VIII. B., Regulatory  
22 Risk, the regulatory environment and the rate decisions by utility commissions have  
23 a direct and significant impact on the financial condition of utilities.

24 **Q. Does PacifiCorp's credit rating benefit because of BHE and its parent**  
25 **Berkshire Hathaway Inc.?**

26 A. Yes. Although ring-fenced, PacifiCorp's credit ratios have been weak for the  
27 ratings level. PacifiCorp has been able to sustain its ratings in part through the

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<sup>9</sup> S&P Ratings Direct, *Assessing U.S. Investor-Owned Utility Regulatory Environments* (Aug. 10, 2016), at 4.

1 acquisition by BHE and its parent, Berkshire Hathaway Inc. S&P was very clear on  
2 this point in its April 2021 assessment of PacifiCorp:

3 Under our group rating methodology, we consider PacifiCorp to be a  
4 core subsidiary of BHE with a group credit profile of ‘a’. The core status  
5 reflects our view that PacifiCorp is highly unlikely to be sold, has strong  
6 long-term commitment from senior management, is successful at what  
7 it does, and contributes meaningfully to the group. Given its core  
8 subsidiary status and BHE’s group credit profile of ‘a’, the issuer credit  
9 rating on PacifiCorp is ‘A’.<sup>10</sup>

10 Moody’s states in their June 2021 credit opinion of PacifiCorp:

11 PacifiCorp benefits from its affiliation with BRK, which requires no  
12 regular dividends from PacifiCorp or BHE. From a credit perspective,  
13 the company's ability to retain its earnings as an entity that is privately  
14 held, particularly by a deep-pocketed sponsor like BRK, is an advantage  
15 over most other investor owned utilities that are typically held to a  
16 regular dividend to their shareholders. PacifiCorp generally pays  
17 dividends that are sized to manage its equity ratio (as measured by  
18 unadjusted equity to equity plus long term debt) around its allowed  
19 levels of slightly higher than 50% (regulations restrict dividends if this  
20 ratio falls below 44%). As of December 2020, PacifiCorp reports its  
21 actual equity percentage, as calculated under this test, was 53%.<sup>11</sup>

22 These examples are evidence of the credit rating benefit resulting from BHE’s  
23 ownership of PacifiCorp.

24 **B. Rating Agency Debt Imputations**

25 **Q. Is PacifiCorp subject to rating agency debt imputation associated with power  
26 purchase agreements (PPAs)?**

27 A. Yes. Rating agencies and financial analysts consider PPAs to be debt-like and will  
28 impute debt and related interest when calculating financial ratios. For example,  
29 S&P will adjust PacifiCorp’s published financial results and impute debt balances  
30 and interest expense resulting from PPAs when assessing creditworthiness. They do  
31 so to obtain a more accurate assessment of a Company’s financial commitments and

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<sup>10</sup> S&P Ratings Direct, *PacifiCorp* (April 5, 2021), at 9.

<sup>11</sup> Moody’s Credit Opinion, *PacifiCorp* (June 30, 2021) at 8.

1 fixed payments. S&P Ratings Direct November 19, 2013, details its view of the  
2 debt aspects of PPAs and other debt imputations, and is included as Confidential  
3 Exhibit PAC/204.

4 **Q. How does this impact PacifiCorp?**

5 A. In its most recent evaluation of PacifiCorp, S&P added approximately \$850 million  
6 of additional debt and \$21 million of related interest expense to the Company's debt  
7 and coverage tests for PPAs and other liabilities of the Company that are considered  
8 to be debt-like by S&P.

9 **Q. How does inclusion of the PPA-related debt and these other adjustments affect  
10 PacifiCorp's capital structure as S&P reviews the Company's credit metrics?**

11 A. Negatively. By including the imputed debt resulting from PPAs and these other  
12 adjustments, PacifiCorp's capital structure has a lower equity component as a  
13 corollary to the higher debt component, lower coverage ratios, and reduced  
14 financial flexibility than what might otherwise appear to be the case from a review  
15 of the book value capital structure. For example, as shown in Table 8, if one were  
16 to apply the total \$850 million amount of debt adjustments that S&P most recently  
17 made to PacifiCorp's proposed capital structure in this case, the resulting common  
18 equity percentage would decline from 52.25 percent to 50.21 percent. If the  
19 Company were to finance at the ordered 50.00 percent, the imputed debt adjustment  
20 would drop the equity level below 50.00 percent and increases the risk of a ratings  
21 down grade.



1

**Table 8: Rating Agency Adjusted Capital**

	Proposed Cap Structure		Rating Agency Adjustments	Adjusted Cap Structure	
	Book Values	% of Total		Book Values	% of Total
Long-Term Debt	\$9,989	47.74%	\$850	\$10,839	49.78 %
Preferred Stock	2	0.01%	(1)	1	0.01 %
Common Equity	10,933	52.25%	-	10,933	50.21 %
	\$20,924	100.00%	\$849	\$21,773	100.00 %

2

**V. CAPITAL STRUCTURE DETERMINATION**

3

**Q. How did the Company determine its recommended capital structure?**

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A. The capital structure is based on the actual capital structure at December 31, 2021 and forecasted capital activity, including known and measurable changes, through December 31, 2023. PacifiCorp averaged the five quarter-end capital structures measured beginning at December 31, 2022, and concluding with December 31, 2023, resulting in a capital structure with an equity component of 52.25 percent.

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The support for these five quarter-end capital structures, spanning the 12-month test period, are provided by the Company in response to Standard Data Request 38 in this general rate case docket. The capital activity includes known maturities of certain debt issues that were outstanding at December 31, 2021, subsequent issuances of long-term debt, and any capital contributions received or dividends paid. The known and measurable changes represent forecasted capital activity since December 31, 2021.

1 **Q. Why does the Company propose a capital structure calculated using a five-**  
2 **quarter average?**

3 A. This approach smooths volatility in the capital structure, which will fluctuate as the  
4 Company expends capital, issues or retires debt, retains earnings, or declares  
5 dividends.

6 **Q. Why is PacifiCorp using capital balances for the 12-month period ending**  
7 **December 31, 2023, rather than the projected capital structure as of the rate**  
8 **effective date?**

9 A. This approach best captures the actual capital structure PacifiCorp forecasts for the  
10 rate effective period.

11 **Q. How does the Company's proposed capital structure compare to the equity**  
12 **ratio of the utility operating company proxy group found in Exhibit PAC/303**  
13 **of Ms. Bulkley's testimony?**

14 A. Ms. Bulkley's exhibit shows the low, high and median of the proxy group average  
15 equity ratios are 46.85 percent, 61.11 percent and 52.71 percent, respectively. The  
16 Company's proposed capital structure is well within this range.

## 17 VI. COST CALCULATIONS

18 **Q. How did you calculate the Company's embedded costs of long-term debt and**  
19 **preferred stock?**

20 A. Consistent with my determination of the percentage capital structure discussed  
21 previously, I have similarly calculated the embedded costs of debt and preferred  
22 stock as an average of the five quarter-end cost calculations spanning the test  
23 period, beginning at December 31, 2022, and concluding with December 31, 2023.

1 **Q. Please explain the cost of long-term debt calculation.**

2 A. I calculated the cost of debt by issue, based on each debt series' interest rate and net  
3 proceeds at the issuance date, to produce a bond yield to maturity for each series of  
4 debt outstanding as of each of the five quarter-ending dates spanning the Test  
5 Period. It should be noted that in the event a bond was issued to refinance a higher  
6 cost bond, the pre-tax premium and unamortized costs, if any, associated with the  
7 refinancing were subtracted from the net proceeds of the bonds that were issued.  
8 Each bond yield was then multiplied by the principal amount outstanding of each  
9 debt issue, resulting in an annualized cost of each debt issue. Aggregating the  
10 annual cost of each debt issue produces the total annualized cost of debt. Dividing  
11 the total annualized cost of debt by the total principal amount of debt outstanding  
12 produces the weighted average cost for all debt issues. The support for each of  
13 these pro-forma weighted average cost of debt calculations as of each of the five  
14 quarter-ending dates spanning the Test Period are provided as attachments by the  
15 Company in response to Standard Data Request 12. The average of these-five  
16 annualized cost of debt calculations, as summarized below, is PacifiCorp's  
17 embedded cost of long-term debt for this proceeding:

1

**Table 9: PacifiCorp Embedded Cost of Long-Term Debt**

	Forecast LT Debt O/S (\$m)	Wt Ave Pro-forma Cost of LT Debt	Cost of Debt calcs provided in response to OR GRC SDR 12
12/31/22	\$ 9,442	4.45%	attach SDR 12-2
03/31/23	9,433	4.46%	attach SDR 12-3
06/30/23	10,433	4.31%	attach SDR 12-4
09/30/23	10,341	4.33%	attach SDR 12-5
12/31/21	10,293	4.36%	attach SDR 12-6
5QE Ave	\$ 9,989	4.38%	

2 **Q. Please describe the changes to the amount of outstanding long-term debt**  
3 **between December 31, 2021, and December 31, 2023?**

4 A. Approximately \$604 million of the Company's fixed rate long-term debt,  
5 respectively, will mature during this period and I have therefore repriced or  
6 removed this debt when appropriate in the determination of the proposed average  
7 cost of debt. Also, as reflected in Exhibit PAC/201, Pro forma Cost of Long-Term  
8 Debt, the Company anticipates new fixed rate long-term debt during the period, a  
9 30-year term issuance of \$800 million in 2022 and a 10- and 30-year split term  
10 issuance totaling \$1,300 million in 2023.

11 **Q. Regarding the \$800 million of new long-term issuances in 2022, how did you**  
12 **determine the interest rate and resulting cost for this new long-term debt?**

13 A. The Company's current estimated credit spread for 30-year debt is 1.20 percent and  
14 the recent forward 30-year U.S. Treasury rates for September 2022 is approximately  
15 2.12 percent. Issuance costs for 30-year debt of this type adds approximately  
16 0.05 percent to the all-in cost. Therefore, as reflected in Exhibit PAC/201, Pro

1 Pro Forma Cost of Long-Term Debt, the Company projects a total all-in cost of long-  
2 term debt of 3.37 percent, for the projected new 30-year long-term debt.

3 **Q. Regarding the \$1.3 billion of new long-term issuances in 2023, how did you**  
4 **determine the interest rate and resulting cost for this new long-term debt?**

5 A. The Company's current estimated credit spread for 10-year and 30-year debt is  
6 0.90 and 1.20 percent, respectively. The recent forward 10-year and 30-year U.S.  
7 Treasury rates for May 2023 are approximately 1.95 and 2.15 percent, respectively.  
8 Issuance costs for 10-year and 30-year debt of this type adds approximately 0.08  
9 and 0.05 percent to the all-in cost, respectively. Therefore, as reflected in Exhibit  
10 PAC/201, Pro Forma Cost of Long-Term Debt, the Company projects a total all-in  
11 cost of long-term debt of 2.93 percent and 3.40 percent, respectively, for the  
12 projected new 10-year and 30-year long-term debt.

13 **Q. A portion of the securities in PacifiCorp's debt portfolio bears variable rates.**  
14 **What is the basis for the projected interest rates used by PacifiCorp?**

15 A. The Company's variable rate long-term debt in this case is in the form of tax-  
16 exempt debt. Exhibit PAC/205, Indicative Forward Pollution Control Revenue  
17 Bonds Variable Rates, shows that, on average, these securities have been trading at  
18 approximately 85 percent of the 30-day London Inter Bank Offer Rate (LIBOR) for  
19 the period January 2000 through December 2021. Therefore, the Company has  
20 applied a factor of 85 percent to the forward Bloomberg 1-Month Short Term Bank  
21 Yield Index (USD) rate as of each of the five quarter-ending dates spanning the Test  
22 Period and then added the respective credit facility and remarketing fees for each  
23 floating rate tax-exempt bond outstanding during the period. Credit facility and

1 remarketing fees are included in the interest component because these are costs  
2 which contribute directly to the interest rate on the securities and are charged to  
3 interest expense. This method is consistent with the Company's past practices when  
4 determining the cost of debt in previous Oregon general rate cases as well as in  
5 other states that regulate PacifiCorp.

6 **Q. Did you make any further adjustments in your pro-forma calculations of the**  
7 **Company's weighted cost of debt over the Test Period?**

8 A. Yes. For the pro-forma weighted average cost of debt calculations made for each of  
9 the five quarter-ending dates spanning the Test Period, as evidenced in the  
10 attachments provided by the Company in response to Standard Data Request 12,  
11 I adjusted the interest rate on the then existing long-term debt scheduled to mature  
12 within one year to reflect expected financing rates. This adjustment is consistent  
13 with the Commission practice as set forth in Order 01-787<sup>12</sup> and with the  
14 Company's practice in cases since that order.

15 **Q. How did you calculate the embedded cost of preferred stock?**

16 A. The embedded cost of preferred stock was calculated by first determining the cost  
17 of money for each issue. I began by dividing the annual dividend per share by the  
18 per share net proceeds for each series of preferred stock. The resulting cost rate  
19 associated with each series was then multiplied by the total par or stated value  
20 outstanding for each issue to yield the annualized cost for each issue. The sum of  
21 annualized costs for each issue produces the total annual cost for the entire  
22 preferred stock portfolio. I then divided the total annual cost by the total amount of

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<sup>12</sup> *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).

1 preferred stock outstanding to produce the weighted average cost for all issues. The  
2 result is PacifiCorp's embedded cost of preferred stock.

3 **A. Embedded Cost of Long-Term Debt**

4 **Q. What is PacifiCorp's embedded cost of long-term debt?**

5 A. The cost of long-term debt is 4.38 percent, as shown in Exhibit PAC/201, Pro forma  
6 Cost of Long-Term Debt.

7 **B. Embedded Cost of Preferred Stock**

8 **Q. What is PacifiCorp's embedded cost of preferred stock?**

9 A. Exhibit PAC/206, Cost of Preferred Stock, shows the embedded costs of preferred  
10 stock to be 6.75 percent.

11 **VII. PENSION COSTS**

12 **Q. Please provide a brief overview of pension costs and pension settlement**  
13 **accounting.**

14 A. The Company incurs net periodic benefit costs for its defined benefit pension plans  
15 each year based on calculations performed by its actuaries in accordance with  
16 Financial Accounting Standards Board's Accounting Standards Codification Topic  
17 715-30—Compensation—Retirement Benefits (ASC 715). The Company's net  
18 periodic benefit cost includes the ASC 715 components of interest cost and  
19 amortization of unrecognized net actuarial losses offset by expected returns on plan  
20 assets. Due to the frozen status of the Company's pension plans, the ASC 715  
21 service cost component is zero.

22 In the event lump sum distributions to retirees in a calendar year exceed the  
23 service cost plus interest cost threshold set forth in ASC 715, settlement accounting

1 is triggered. (Due to service cost being zero for the Company's pension plans, the  
2 threshold is simply interest cost). This results in accelerated recognition of a  
3 portion of unrecognized net actuarial losses that are otherwise amortized over the  
4 average remaining lives of plan participants through normal net periodic benefit  
5 cost under ASC 715. Absent recovery of the settlement loss being probable of  
6 recovery (in which case the loss would be deferred to a regulatory asset), the  
7 settlement loss is required to be immediately charged to expense under ASC 715.  
8 As indicated, the settlement loss is not incremental to expense that would have  
9 otherwise been recognized; rather it is simply a timing difference.

10 For further details regarding pension settlement accounting and the  
11 Company's pension plans, please refer to my direct testimony in docket UE 374  
12 Exhibit PAC/300.

13 **Q. Has the Company filed a deferral request as a result of pension settlement**  
14 **losses since the Commission issued its order in the Company's 2021 Rate Case**  
15 **and if so, what was the rationale for such a filing?**

16 A. Yes. On July 27, 2021, the Company filed an application for a deferred accounting  
17 and accounting order related to its defined benefit plans.<sup>13</sup> This application was  
18 filed in anticipation of reaching the settlement accounting threshold at the end of  
19 July 2021 and on the basis of the Commission's order in the Company's 2021 Rate  
20 Case, which states in part:

21 We will consider a request by the company to address a pension  
22 settlement loss occurring during the test year, in the event it occurs,  
23 but would expect such a filing to address the concerns noted above,

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<sup>13</sup> *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans*, Docket No. UM 2185, Application filed July 27, 2021.



1 regarding a potential for over-recovery, as well as certain other  
2 considerations discussed below. We recognize that without a  
3 deferral order in place, if the company does incur a pension  
4 settlement loss in the test year, it may have to be expensed.<sup>14</sup>

5 **Q. In its application, how did the Company address the Commission’s concern**  
6 **regarding the potential over-recovery quoted in the excerpt above?**

7 A. The Company proposed that upon triggering of a settlement loss, amortization  
8 begin immediately over the average remaining lives of plan participants in order to  
9 align with the amortization component of net period benefit cost reflected in  
10 revenue requirement in the Company’s 2021 Rate Case. This approach eliminates  
11 the concern of potential double recovery since no rate change would occur between  
12 the point of the settlement loss being triggered and the Company’s next general rate  
13 case, yet the Company would continue to amortize the losses at a level similar to  
14 that already reflected in base rates.

15 **Q. What is the status of docket UM 2185 and what is being proposed in this filing?**

16 A. As there has been no activity on docket UM 2185, the Company proposes the  
17 application be addressed through this filing, and thus I will address the 2021  
18 settlement loss activity in my testimony. Please see Ms. Joelle R. Steward’s  
19 testimony for a discussion of the Company’s motion to consolidate various open  
20 deferral proceedings.

21 **Q. Please provide an update regarding pension settlement losses that occurred in**  
22 **the 2021 test period of the Company’s 2021 Rate Case.**

23 A. As indicated in the Company’s application in docket UM 2185, settlement  
24 accounting was expected to be triggered at July 31, 2021. At that date, lump sum

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<sup>14</sup> Order No. 20-473 at 95.

1 distributions totaled \$28.823 million and exceeded the settlement loss accounting  
2 threshold of \$26.097 million. As a result, an interim remeasurement of the plan  
3 assets and benefit obligation occurred and an \$8.947 million settlement loss was  
4 recognized. The plan assets and benefit obligation were again remeasured at  
5 December 31, 2021 and an additional \$6.699 million settlement loss was  
6 recognized. Thus, on a total-company basis, pension settlement losses totaled  
7 \$15.646 million in 2021.

8 **Q. Please describe the Company's accounting for Oregon's share of the 2021**  
9 **settlement losses and in particular how the Commission's concern regarding**  
10 **potential double recovery was addressed.**

11 A. For each of the July 31, 2021 and December 31, 2021 settlement losses, the  
12 Company deferred Oregon's system-allocated share to a regulatory asset with  
13 amortization over the approximately 20-year average remaining life expectancy of  
14 plan participants beginning immediately (i.e., effective August 1, 2021 for the July  
15 loss and January 1, 2022 for the December loss). As a result, amortization of these  
16 losses approximates what is currently reflected in base rates from the Company's  
17 2021 Rate Case. This treatment is consistent with the Commission's Order in the  
18 Company's 2021 Rate Case, which states in part:

19 We also note that PacifiCorp, would however, continue to recover  
20 through base rates an amount for FAS 87 pension expense that is  
21 unadjusted for that settlement loss, even though, all else held equal,  
22 its actual pension expense after 2021 would be reduced by the  
23 accelerated recognition of this expense. In this way, the company  
24 will still recover a portion of that accelerated expense over time,  
25 until rates are reset in a future case or some other regulatory action  
26 were taken. If the company makes a future request to defer a pension

1 settlement loss in the test year, we expect the company's proposal  
2 would account for this dynamic.<sup>15</sup>

3 Due to the proximity of the 2021 settlement losses to the timing of when  
4 base rates reset, and with a similar level of amortization reflected in base rates, the  
5 Company deferred the 2021 settlement losses to a regulatory asset.

6 **Q. How have the 2021 pension settlement losses been reflected in this filing?**

7 A. Based on the above-described accounting for the 2021 settlement losses,  
8 approximately 1/20<sup>th</sup> of those losses is included in the forecast Test Period pension  
9 cost.

10 **Q. Please describe any additional pension settlement loss related activity  
11 projected after 2021 and how such amounts, if any, are reflected in this filing.**

12 A. The Company's actuaries have projected settlement losses of \$9.781 million and  
13 \$7.145 million in 2022 and 2023, respectively, with the threshold assumed to be  
14 surpassed at the end of the respective year and amortization beginning immediately.  
15 Thus, approximately 1/20<sup>th</sup> of the \$9.781 million projected 2022 settlement loss is  
16 included in the forecast Test Period pension cost. Due to the 2023 settlement loss  
17 assumed to occur at year-end, no specific amortization or recognition of that loss is  
18 included in the forecast Test Period pension cost; rather, the associated  
19 unrecognized loss is included in the forecast Test Period expense based on the  
20 normal amortization component of net periodic pension cost. This approach to the  
21 projected 2022 and 2023 settlements losses is also consistent with the  
22 Commission's Order in the Company's 2021 Rate Case quoted above.

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<sup>15</sup> Order No. 20-473 at 95-96.

**VIII. CONCLUSION**

1

2 **Q. Please summarize your recommendations to the Commission.**

3 A. I respectfully request the Commission adopt PacifiCorp's proposed capital structure  
4 with a common equity level of 52.25 percent. This capital structure balances the  
5 financial integrity of the Company and costs to customers by reflecting the  
6 minimum equity ratio necessary for PacifiCorp to maintain its ratings under current  
7 market conditions. When combined with PacifiCorp's updated cost of long-term  
8 debt of 4.38 percent and the cost of equity of 9.80 percent recommended by  
9 Ms. Bulkley, this produces a reasonable overall cost of capital of 7.21 percent.

10 I also respectfully request the Commission accept the Company's 2021  
11 actual pension settlement losses and projected 2022 pension settlement loss in base  
12 rates by allowing them to be amortized over the average remaining lives of plan  
13 participants (approximately 20 years) as reflected in the Company's revenue  
14 requirement in this filing.

15 **Q. Does this conclude your direct testimony?**

16 A. Yes.

Docket No. UE 399  
Exhibit PAC/201  
Witness: Nikki L. Koblaha

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Nikki L. Koblaha  
Pro forma Cost of Long-Term Debt**

**March 2022**

**PACIFICORP**  
**Electric Operations**  
**Pro Forma Ave Cost of Long-Term Debt Summary**  
**12 months ended December 31, 2023**

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	<b>Total First Mortgage Bonds</b>	<b>\$9,803,690,000</b>	<b>(\$111,131,695)</b>	<b>(\$2,073,225)</b>	<b>\$9,690,485,080</b>	<b>\$434,218,750</b>	<b>4.351%</b>	<b>4.429%</b>	<b>27.0</b>	2
3										3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	\$160,460,000	(\$3,962,932)	(\$1,745,495)	\$154,751,573	\$2,584,931	1.461%	1.611%	30.0	4
5	Subtotal - Pollution Control Revenue Bonds	\$24,400,000	(\$225,000)	(\$428,469)	\$23,746,531	\$373,076	1.417%	1.529%	29.9	5
6	<b>Total Pollution Control Revenue Bonds</b>	<b>\$184,860,000</b>	<b>(\$4,187,932)</b>	<b>(\$2,173,964)</b>	<b>\$178,498,103</b>	<b>\$2,958,007</b>	<b>1.455%</b>	<b>1.600%</b>	<b>29.9</b>	6
7										7
8	Loss on Long Term Debt Reacquisitions, without Refunding					\$205,126				8
9	<b>Total Cost of Long Term Debt</b>	<b>\$9,988,550,000</b>	<b>(\$115,319,627)</b>	<b>(\$4,247,189)</b>	<b>\$9,868,983,183</b>	<b>\$437,381,884</b>	<b>4.297%</b>	<b>4.379%</b>	<b>27.0</b>	9
10										10

**PACIFICORP**  
**Electric Operations**  
**Pro Forma Ave Cost of Long-Term Debt Detail**  
**12 months ended December 31, 2023**

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT		(DISC)/PREM & ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY		MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
						ORIGINAL ISSUE	SQE AVE OUTSTANDING			TOTAL DOLLAR AMOUNT	PER \$100 PRINCIPAL AMOUNT			
	(a)	(b)	(c)	(d)	(e)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1														1
2														2
3	3.600%	Series due Apr 2024	03/13/14	04/01/24	10	\$425,000,000	\$170,000,000	(\$1,440,066)	(\$777,230)	\$167,782,705	\$98.696	3.757%	\$6,386,900	3
4	3.350%	Series due Jul 2025	06/19/15	07/01/25	10	\$250,000,000	\$250,000,000	(\$2,441,421)	\$0	\$247,558,579	\$99.023	3.466%	\$8,665,000	4
5	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	5
6	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	6
7	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	7
8	2.846%	Proforma Series#2	05/15/23	05/15/33	10	\$650,000,000	\$390,000,000	(\$2,698,320)	\$0	\$387,301,680	\$99.308	2.926%	\$11,411,400	8
9	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	9
10	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	10
11	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	11
12	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	12
13	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	13
14	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	14
15	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	15
16	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	16
17	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	17
18	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	18
19	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	19
20	2.900%	Series due June 2052	07/09/21	06/15/52	31	\$1,000,000,000	\$1,000,000,000	(\$16,597,874)	\$0	\$983,402,126	\$98.340	2.982%	\$29,820,000	20
21	3.324%	Proforma Series#1	09/15/22	09/15/52	30	\$800,000,000	\$800,000,000	(\$7,250,400)	\$0	\$792,749,600	\$99.094	3.373%	\$26,984,000	21
22	3.349%	Proforma Series#3	05/15/23	05/15/53	30	\$650,000,000	\$390,000,000	(\$3,478,320)	\$0	\$386,521,680	\$99.108	3.396%	\$13,244,400	22
23	3.366%	Series - Cur Mat LT Debt (repriced)	12/31/23	12/31/53	30		\$503,690,000	(\$4,676,059)	\$0	\$499,013,941	\$99.072	3.416%	\$17,206,050	23
24	4.326%	<b>Subtotal - Bullet FMBs</b>			27		<b>\$9,703,690,000</b>	<b>(\$110,227,228)</b>	<b>(\$2,073,225)</b>	<b>\$9,591,389,547</b>		<b>4.405%</b>	<b>\$427,437,750</b>	24
25														25
26														26
27	6.710%	Series G due Jan 2026	01/23/96	01/15/26	30	\$100,000,000	\$100,000,000	(\$904,467)	\$0	\$99,095,533	\$99.096	6.781%	\$6,781,000	27
28	6.710%	<b>Subtotal - Series G MTNs</b>			30		<b>\$100,000,000</b>	<b>(\$904,467)</b>	<b>\$0</b>	<b>\$99,095,533</b>		<b>6.781%</b>	<b>\$6,781,000</b>	28
29														29
30	4.351%	<b>Total First Mortgage Bonds</b>			27		<b>\$9,803,690,000</b>	<b>(\$111,131,695)</b>	<b>(\$2,073,225)</b>	<b>\$9,690,485,080</b>		<b>4.429%</b>	<b>\$434,218,750</b>	30
31														31
32														32
33	1.473%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	\$8,190,000	\$6,552,000	(\$167,822)	(\$69,058)	\$6,315,119	\$96.385	1.626%	\$106,536	33
34	1.427%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	\$121,940,000	\$97,552,000	(\$2,619,397)	(\$1,540,614)	\$93,391,990	\$95.736	1.607%	\$1,567,661	34
35	1.610%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	\$15,060,000	\$12,048,000	(\$338,286)	(\$65,142)	\$11,644,572	\$96.651	1.754%	\$211,322	35
36	1.510%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	\$21,260,000	\$17,008,000	(\$408,383)	(\$70,682)	\$16,528,935	\$97.183	1.629%	\$277,060	36
37	1.398%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	\$5,300,000	\$5,300,000	(\$105,635)	\$0	\$5,194,365	\$98.007	1.481%	\$78,493	37
38	1.501%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	\$22,000,000	\$22,000,000	(\$323,409)	\$0	\$21,676,591	\$98.530	1.563%	\$343,860	38
39	1.461%	<b>Subtotal - Secured PCRBS</b>			30		<b>\$160,460,000</b>	<b>(\$3,962,932)</b>	<b>(\$1,745,495)</b>	<b>\$154,751,573</b>		<b>1.611%</b>	<b>\$2,584,931</b>	39
40														40
41	1.417%	Sweetwater 95 due Nov 2025	12/14/95	11/01/25	30	\$24,400,000	\$24,400,000	(\$225,000)	(\$428,469)	\$23,746,531	\$97.322	1.529%	\$373,076	41
42	1.417%	<b>Subtotal - Unsecured PCRBS</b>			30		<b>\$24,400,000</b>	<b>(\$225,000)</b>	<b>(\$428,469)</b>	<b>\$23,746,531</b>		<b>1.529%</b>	<b>\$373,076</b>	42
43														43
44	1.455%	<b>Total PCR B Obligations</b>			30		<b>\$184,860,000</b>	<b>(\$4,187,932)</b>	<b>(\$2,173,964)</b>	<b>\$178,498,103</b>		<b>1.600%</b>	<b>\$2,958,007</b>	44
45														45
46			REACQ DATE	ORG MAT DATE										46
47														47
48		8.375% Series A QUIDS	11/17/00	06/30/35									\$107,887	48
49		8.55% Series B QUIDS	11/17/00	12/31/25									\$84,084	49
50		Carbon '94 PCR B Series	02/18/16	11/01/24									\$13,155	50
51		<b>Long-Term Debt Recapitulation, without refunding amortization</b>											<b>\$205,126</b>	51
52														52

Exhibit PAC/201  
Koblfhar2

**PACIFICORP**  
**Electric Operations**  
**Pro Forma Ave Cost of Long-Term Debt Detail**  
**12 months ended December 31, 2023**

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT		(DISC)/PREM & ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY		MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
						ORIGINAL ISSUE	5QE AVE OUTSTANDING			TOTAL DOLLAR AMOUNT	PER \$100 PRINCIPAL AMOUNT			
	(a)	(b)	(c)	(d)	(e)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
53	4.297%	Total Long-Term Debt			27		\$9,988,550,000	(\$115,319,627)	(\$4,247,189)	\$9,868,983,183		4.379%	\$437,381,884	53
54														54



Docket No. UE 399  
Exhibit PAC/202  
Witness: Nikki L. Koblaha

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Nikki L. Koblaha  
Arizona Public Service Company October 2008 Letter to the  
Arizona Corporation Commission**

**March 2022**



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PINNACLE WEST  
CAPITAL CORPORATION

LAW DEPARTMENT

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DOCKET CONTROL

October 17, 2008

Arizona Corporation Commission

DOCKETED

OCT 17 2008

DOCKETED BY MM

Commissioner Kristin K. Mayes  
Arizona Corporation Commission  
1200 West Washington  
Phoenix, Arizona 85007

Re: Docket No. E-01345A-08-0172 (Interim Rate Motion)

Dear Commissioner Mayes:

On October 8, 2008, you filed a letter in which you requested Arizona Public Service Company ("APS" or "Company") to respond to five specific issues covering a range of subjects. Because several of these issues are germane to the Company's pending Motion for Interim Rates, the Company has chosen to submit its response in the above docket. For the convenience of the parties to this proceeding, I have attached a copy of your October 8<sup>th</sup> letter as Appendix A.

**APS Access to Commercial Paper Market and Other Credit-Related Issues**

APS first began experiencing trouble accessing the commercial paper market in August of 2007 when the sub-prime credit issues began to impact the capital markets. Access has continued to be sporadic throughout 2008, with the amount of commercial paper APS can issue often being limited even when access to the market was possible. Beginning September 17, 2008, the commercial paper market has been completely closed to APS.

As discussed during the hearing, APS had total lines of credit of \$900 million. The first line of \$400 million expires at the end of 2010, with a second for \$500 million expiring at the end of 2011. The purpose of these lines of credit is to provide the Company with liquidity and working capital when commercial paper cannot be utilized – not fund capital expenditures.<sup>1</sup> Indeed, Decision No. 69947 (October 30, 2007) specifically limited the use of the \$500 million line of credit to fuel/purchased power requirements and thus cannot be used to fund the Company's capital requirements. As of September 30, 2008, approximately \$270 million had to be drawn down due to the problems in the commercial paper market described above. Also, \$34 million of the Company's credit line was with bankrupt Lehman Brothers and thus no longer

<sup>1</sup> Borrowing on bank lines of credit is normally 25 to 50 basis points more expensive than commercial paper.

APS • APS Energy Services • SunCor • El Dorado •

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Kristin K. Mayes, Commissioner  
October 17, 2008  
Page 2

exists. Another \$36 million was with Wachovia, which is in the process of being acquired by Wells Fargo. Whether the new owner of Wachovia will assume the \$36 million commitment is uncertain, to say the least. Accordingly, APS's previous \$900 million lines of credit are now no more than \$866 million, and may be as low as \$830 million. Finally, as a result of recent write-downs of bank assets, there is \$2 trillion less credit capacity in the U.S. banking system than there was before this global financial crisis began. As a result, APS will likely encounter difficulty in maintaining its remaining lines of credit in the future, and there is no doubt that these lines of credit would, in any case, be insufficient to meet APS's capital expenditure needs over the next few years.

Liquidity is absolutely vital to the financial integrity of an electric utility. APS itself was contacted by each of the three rating agencies after the Lehman Brothers bankruptcy and asked about the Company's exposure to Lehman, Morgan Stanley, Merrill Lynch and Goldman Sachs, as well as its ability to count on its lines of credit given the chaos in the short-term credit markets. A recent example of the critical importance of liquidity is Constellation Energy, the parent of Baltimore Gas & Electric Company, which began 2008 with a stock price of over \$100 per share. After facing a liquidity crisis driven by threatened credit rating downgrades and the resultant cash collateral calls that nearly drove Constellation to the brink of bankruptcy, it was forced to sell itself to MidAmerican Energy (the same entity that bought out PacifiCorp) for \$26.50 per share.

And the damage has not been limited to the short-term debt market. Despite massive efforts by our Federal government and governments in Europe and Asia to pump liquidity into the national and international credit markets, access to the corporate debt market is extremely strained, with only the most highly-rated corporations being successful in raising long-term debt capital. At present, APS likely could not successfully issue long-term debt. Whether this financial market environment will improve by the spring of next year, when APS likely will need to issue debt, is unknown.

### **GeoSmart Solar Financing Program**

On Thursday, September 25, 2008 GE Money announced that it will no longer offer unsecured installment consumer financing for its energy efficiency and renewable energy programs after October 23, 2008 because of the current turmoil in the credit markets. The action specifically affected the Electric & Gas Industries Association's ("EGIA") *GEOSmart* Financing Program offered by APS because GE Money provided the financial support for the program. Although APS had no prior warning of GE Money's actions, APS remains committed to its partnership with EGIA. EGIA, as a non-profit entity implementing similar financing programs for utilities around the country, is situated to identify other suitable financial institutions to back the *GeoSmart* program. In recent conversations, EGIA informed APS that a number of financial institutions have been identified that **may** be able to provide funding for *GEOSmart*. APS remains hopeful but cannot offer any assurance that EGIA will secure other financial backing in the future.

Kristin K. Mayes, Commissioner  
October 17, 2008  
Page 3

### **Transactions with Investment Banks or Similar Financial Institutions**

Attached as Appendix B is a list of the banks with which APS has existing lines of credit. As noted before, Lehman Brothers and Wachovia are in that group. APS has also submitted a \$1.1 million claim against Lehman Brothers in bankruptcy over a hedging transaction. APS has conducted numerous transactions with Morgan Stanley and Goldman Sachs, who together are major players in the U.S energy markets. Although it would seriously reduce the overall liquidity of these energy markets should Morgan Stanley and/or Goldman Sachs bow out of the energy market, APS itself had controls in place well before all these problems began that limited its exposure to any single trading partner, including those discussed above. However, with chaotic and unprecedented market events such as we are presently experiencing, no amount of internal controls can provide complete protection against potential losses.<sup>2</sup> Finally, AIG is a carrier for APS property and casualty insurance. APS believes that these insurance policies will continue to be honored.

### **Auction Rate Securities**

APS does not have any funds invested in auction rate securities ("ARS"). APS is an issuer of ARS, with \$343 million outstanding and with maturities in 2029 and 2034. The average rate of interest paid on these securities has been 3.2%, thus providing very attractive financing for APS and its customers.

### **Palo Verde**

Palo Verde Unit 3 experienced two relatively brief unplanned outages recently. The first was from September 16 to September 20 when a failed transmitter in the control circuitry for one of the two power supplies to the reactor control rods required the unit to be shut down. That was safely accomplished, and after the electronic card that included the failed component was replaced, the unit was returned to full power without incident. The second was from September 27 to 30 when high sulfate levels were detected in the secondary steam system (the system that connects the steam generators with the steam turbine). After operators had shut down the unit, the secondary system chemistry was returned to normal, the unit again returned to service without incident and has been operating at full power since then. APS estimates that the amount of additional fuel and purchased power costs deferred for recovery through the PSA to be approximately \$3 million.<sup>3</sup>

Neither outage involved what could be characterized as an unusual event for a nuclear power plant and is the sort of occurrence anticipated in the budgeted effective forced outage rate ("EFOR") for Palo Verde. Palo Verde, like all generators, including all APS generators, has an

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<sup>2</sup> Although such transactions are not directly with APS, the APS decommissioning trusts and the Pinnacle West retirement funds have relatively small investments in some of the troubled entities identified in your letter, as likely do most if not all large investment funds in this country.

<sup>3</sup> As the Commission is aware, APS absorbs 10% of higher fuel costs, and a portion of outage costs are embedded in the base fuel cost. In addition, a small amount is allocated to wholesale customers. Thus, the total cost of the outages was \$4.4 million.

Kristin K. Mayes, Commissioner  
October 17, 2008  
Page 4

anticipated EFOR based primarily on past operations. This is merely an acknowledgement that all machines, no matter how well designed, constructed, operated, and maintained, will sometimes fail. Electric generators are no exception to that rule.

To date this year, the overall Palo Verde capacity factor has been 98% (excluding refueling outages). This past summer, Palo Verde set an all-time record for generation.

Throughout both outage events, Palo Verde staff demonstrated their safety-first focus by using effective problem identification and resolution behaviors, took proper action during troubleshooting (including developing contingency plans) and work planning. They executed all needed repairs with a focus on human performance. The NRC was kept fully informed throughout these outages and monitored Palo Verde's decision-making process and the actions taken. APS does not believe these outages have had any negative impact on APS's substantial progress in resolving the NRC's Confirmatory Action Letter.

Sincerely,



Thomas L. Mumaw

Attorney for Arizona Public  
Service Company

Attachments

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# Appendix A



**COMMISSIONERS**  
MIKE GLEASON - Chairman  
WILLIAM A. MUNDELL  
JEFF HATCH-MILLER  
KRISTIN K. MAYES  
GARY PIERCE



**ARIZONA CORPORATION COMMISSION**

KRISTIN K. MAYES  
Commissioner

Direct Line: (602) 542-4143  
Fax: (602) 542-0765  
E-mail: kmayes@azcc.gov

October 8, 2008

Mr. Don Brandt  
President and CEO  
Arizona Public Service  
400 No. Fifth Street  
M.S. 9042  
Phoenix, AZ 85004

**Re: Impact of recent financial crisis on APS' access to commercial paper markets and ability to finance capital projects; forced cancellation of GeoSmart Solar Loan Program; transactions with investment banks; exposure to auction rate securities; status of outages at Palo Verde Nuclear Generating Station's Unit 3.**

Dear Mr. Brandt:

As you know, the recent upheaval in America's financial markets has had an unsettling effect on our national and local economies. It has also had serious consequences for individuals and companies who need to access financing, as credit tightens and capital markets become less fluid.

In recognition of the current environment, I write to request that you provide the Commission with information regarding whether the unfolding events on Wall Street have had an impact on Arizona Public Service Company ("APS"), with a particular focus on several areas.

First, please tell the Commission whether APS has experienced difficulty gaining access to short or long term debt markets. In particular, have you seen a decline in the Company's ability to issue commercial paper, a practice that has become common among large utilities seeking to make payments for short term capital expenditures and operating expenses. If so, please describe the ways in which you have responded to this deficiency in order to meet the Company's capital needs. Have you experienced additional expenses associated with accessing these markets? What is the short-term and long-term impact to APS' planned capital projects?

Second, APS recently reported to my office that it was forced to scuttle its GeoSmart Solar Financing Program – the program by which APS was offering loans to customers wishing to install solar panels who could not afford to do so solely using rebates – because General Electric pulled its funding due to the credit crisis. Please detail the circumstances surrounding this program suspension and whether you believe APS will be able to re-start the program in the future. Please also inform the Commission whether any other renewable energy or other capital expenditure programs have been threatened or come under pressure as a result of the tightened credit markets, and the Company's strategy for addressing these pressures.

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Third, please tell the Commission whether APS engaged in any significant financial transactions with Lehman Brothers, American International Group, Bear Stearns, or any other investment firm that has been the subject of recent bankruptcies or governmental takeovers. If so, please detail those transactions, and to what extent they have impacted the Company.

Fourth, it is my understanding that APS has had some exposure to auction rate securities. As you know, the auction rate securities market recently collapsed. Please describe the Company's auction rate securities holdings, what worth those securities now have, and what the Company intends to do with those securities in order to minimize any losses associated with them.

Finally, as you know, Palo Verde Nuclear Generating Station's ("PVNGS") Unit Three was down from September 27<sup>th</sup> to October 1<sup>st</sup> – making for a second outage in less than a month. Please tell the Commission how these Unit Three outages will impact the Company's efforts to resolve PVNGS' Category Four status with the Nuclear Regulatory Commission, as well as the estimated replacement costs that have been passed through the Company's Purchased Power and Fuel Adjustment Clause as a result of these outages.

Thank you for your attention to these questions.

Sincerely,



Kris Mayes  
Commissioner

Cc: Chairman Mike Gleason  
Commissioner William A. Mundell  
Commissioner Jeff Hatch-Miller  
Commissioner Gary Pierce  
Ernest Johnson  
Janice Alward  
Brian McNeil  
Rebecca Wilder

# Appendix B

APPENDIX B  
Page 1 of 1

APS Revolving Lines of Credit  
(\$K)

	Bank	Amount	% of Total
1	Bank of America	\$92,857	10.3%
2	Bank of New York Mellon	80,000	8.9%
3	Citigroup	76,572	8.5%
4	JPMorgan	76,572	8.5%
5	Keybank	68,571	7.6%
6	CSFB	60,857	6.7%
7	Barclays Bank	52,857	5.9%
8	Wells Fargo	52,857	5.9%
9	UBS Warburg	52,857	5.9%
10	Union Bank	38,571	4.3%
11	Sun Trust	36,000	4.0%
12	Mizuho	28,571	3.2%
13	KBC Bank	24,000	2.7%
14	Dresdner	24,000	2.7%
15	US Bank	17,143	1.9%
16	Chang Hwa Commercial Bk	15,000	1.6%
17	BOTM	11,429	1.3%
18	Northern Trust	11,429	1.3%
19	Bank Hapoalim	10,000	1.1%
20	Subtotal	\$830,143	92.3%
21	Wachovia	36,000	4.0%
22	Lehman Brothers	33,857	3.7%
23	Total	\$900,000	100.0%

Docket No. UE 399  
Exhibit PAC/203  
Witness: Nikki L. Koblaha

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Nikki L. Koblaha  
New Debt Issue Spreads**

**March 2022**

**PACIFICORP**  
**Electric Operations**  
**Pro Forma Cost of Long-Term Debt Detail**  
**12 months ended December 31, 2023**

LINE NO.	INTEREST RATE	DESCRIPTION	PRINCIPAL AMOUNT		(DISC)/PREM & ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY		MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
			ORIGINAL ISSUE	5QE AVE OUTSTANDING			TOTAL DOLLAR AMOUNT	PER \$100 PRINCIPAL AMOUNT			
	(a)	(b)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
53	4.297%	Total Long-Term Debt		\$9,988,550,000	(\$115,319,627)	(\$4,247,189)	\$9,868,983,183		4.379%	\$437,381,884	53
	4.146%	Actual Post Acquisition Debt Issuances (1)		\$8,903,690,000	(\$99,919,403)	(\$777,230)	\$8,802,993,368		4.22%	\$375,921,750	
	4.674%	Pro Forma Post Acquisition Debt Issuances		\$8,903,690,000	(\$84,671,670)	(\$777,230)	\$8,818,241,100		4.74%	\$421,954,214	
	4.767%	Total Long-Term Debt - Pro Forma		\$9,988,550,000	(\$100,071,895)	(\$4,247,189)	\$9,884,230,916		4.840%	\$483,414,347	

**REDACTED**  
Docket No. UE 399  
Exhibit PAC/204  
Witness: Nikki L. Koblaha

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**REDACTED**

**Exhibit Accompanying Direct Testimony of Nikki L. Koblaha  
S&P Ratings Direct November 19, 2013**

**March 2022**

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



Docket No. UE 399  
Exhibit PAC/205  
Witness: Nikki L. Koblaha

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Nikki L. Koblaha  
Indicative Forward Pollution Control Revenue Bonds Variable Rates**

**March 2022**

**Indicative Forward PCRB Variable Rates  
For Quarter End Periods for Year Ending December 31, 2023**

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR (b)/(a)
	(a)	(b)	
Jan-00	5.81%	3.33%	57%
Feb-00	5.89%	3.62%	62%
Mar-00	6.05%	3.68%	61%
Apr-00	6.16%	4.02%	65%
May-00	6.54%	4.89%	75%
Jun-00	6.65%	4.35%	65%
Jul-00	6.63%	3.99%	60%
Aug-00	6.62%	4.09%	62%
Sep-00	6.62%	4.50%	68%
Oct-00	6.62%	4.36%	66%
Nov-00	6.63%	4.33%	65%
Dec-00	6.68%	4.14%	62%
Jan-01	5.88%	3.10%	53%
Feb-01	5.53%	3.59%	65%
Mar-01	5.13%	3.18%	62%
Apr-01	4.82%	3.72%	77%
May-01	4.16%	3.38%	81%
Jun-01	3.92%	3.03%	77%
Jul-01	3.82%	2.65%	69%
Aug-01	3.64%	2.36%	65%
Sep-01	3.17%	2.42%	76%
Oct-01	2.48%	2.18%	88%
Nov-01	2.13%	1.79%	84%
Dec-01	1.96%	1.64%	84%
Jan-02	1.81%	1.49%	82%
Feb-02	1.85%	1.39%	75%
Mar-02	1.89%	1.46%	77%
Apr-02	1.86%	1.58%	85%
May-02	1.84%	1.67%	91%
Jun-02	1.84%	1.58%	86%
Jul-02	1.83%	1.49%	81%
Aug-02	1.80%	1.49%	83%
Sep-02	1.82%	1.69%	93%
Oct-02	1.81%	1.84%	102%
Nov-02	1.44%	1.66%	115%
Dec-02	1.42%	1.57%	110%
Jan-03	1.36%	1.40%	103%
Feb-03	1.34%	1.43%	107%
Mar-03	1.31%	1.45%	111%
Apr-03	1.31%	1.52%	115%
May-03	1.31%	1.56%	119%
Jun-03	1.16%	1.38%	119%
Jul-03	1.11%	1.12%	102%
Aug-03	1.11%	1.16%	104%
Sep-03	1.12%	1.24%	111%
Oct-03	1.12%	1.24%	111%
Nov-03	1.13%	1.36%	121%
Dec-03	1.15%	1.32%	114%
Jan-04	1.11%	1.21%	110%
Feb-04	1.10%	1.17%	107%
Mar-04	1.09%	1.20%	110%
Apr-04	1.10%	1.27%	115%
May-04	1.10%	1.29%	117%
Jun-04	1.25%	1.28%	102%
Jul-04	1.41%	1.26%	89%
Aug-04	1.60%	1.40%	88%
Sep-04	1.78%	1.49%	83%
Oct-04	1.90%	1.72%	91%
Nov-04	2.19%	1.65%	75%
Dec-04	2.39%	1.67%	70%
Jan-05	2.49%	1.78%	72%
Feb-05	2.61%	1.88%	72%
Mar-05	2.81%	1.95%	69%
Apr-05	2.97%	2.50%	84%
May-05	3.09%	2.93%	95%
Jun-05	3.25%	2.39%	74%
Jul-05	3.43%	2.28%	67%
Aug-05	3.69%	2.44%	66%
Sep-05	3.78%	2.55%	68%
Oct-05	3.99%	2.66%	67%
Nov-05	4.15%	2.93%	71%
Dec-05	4.36%	3.10%	71%
Jan-06	4.48%	3.02%	67%
Feb-06	4.58%	3.13%	68%

**Indicative Forward PCRB Variable Rates  
For Quarter End Periods for Year Ending December 31, 2023**

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR (b)/(a)
	(a)	(b)	
Mar-06	4.76%	3.11%	65%
Apr-06	4.92%	3.45%	70%
May-06	5.08%	3.52%	69%
Jun-06	5.24%	3.74%	71%
Jul-06	5.37%	3.60%	67%
Aug-06	5.35%	3.53%	66%
Sep-06	5.33%	3.61%	68%
Oct-06	5.32%	3.57%	67%
Nov-06	5.32%	3.62%	68%
Dec-06	5.35%	3.70%	69%
Jan-07	5.32%	3.64%	68%
Feb-07	5.32%	3.63%	68%
Mar-07	5.32%	3.64%	68%
Apr-07	5.32%	3.79%	71%
May-07	5.32%	3.90%	73%
Jun-07	5.32%	3.76%	71%
Jul-07	5.32%	3.66%	69%
Aug-07	5.52%	3.76%	68%
Sep-07	5.48%	3.84%	70%
Oct-07	4.98%	3.56%	72%
Nov-07	4.75%	3.53%	74%
Dec-07	5.00%	3.25%	65%
Jan-08	3.95%	3.02%	76%
Feb-08	3.14%	2.86%	91%
Mar-08	2.80%	3.79%	135%
Apr-08	2.79%	2.23%	80%
May-08	2.63%	1.93%	73%
Jun-08	2.47%	2.77%	112%
Jul-08	2.46%	4.12%	168%
Aug-08	2.47%	3.03%	123%
Sep-08	2.94%	4.57%	155%
Oct-08	3.87%	4.89%	126%
Nov-08	1.68%	2.34%	139%
Dec-08	1.01%	1.02%	101%
Jan-09	0.39%	0.70%	181%
Feb-09	0.46%	0.68%	147%
Mar-09	0.53%	0.66%	124%
Apr-09	0.45%	0.63%	140%
May-09	0.35%	0.53%	153%
Jun-09	0.32%	0.45%	143%
Jul-09	0.29%	0.41%	142%
Aug-09	0.27%	0.43%	158%
Sep-09	0.25%	0.40%	161%
Oct-09	0.24%	0.39%	159%
Nov-09	0.24%	0.37%	157%
Dec-09	0.23%	0.38%	165%
Jan-10	0.23%	0.32%	138%
Feb-10	0.23%	0.32%	137%
Mar-10	0.24%	0.32%	135%
Apr-10	0.26%	0.35%	134%
May-10	0.33%	0.34%	101%
Jun-10	0.35%	0.33%	93%
Jul-10	0.33%	0.30%	90%
Aug-10	0.27%	0.31%	115%
Sep-10	0.26%	0.31%	119%
Oct-10	0.26%	0.27%	106%
Nov-10	0.25%	0.27%	107%
Dec-10	0.26%	0.29%	110%
Jan-11	0.26%	0.26%	100%
Feb-11	0.26%	0.26%	98%
Mar-11	0.25%	0.24%	96%
Apr-11	0.22%	0.24%	106%
May-11	0.20%	0.20%	100%
Jun-11	0.19%	0.12%	62%
Jul-11	0.19%	0.07%	38%
Aug-11	0.21%	0.18%	83%
Sep-11	0.23%	0.18%	78%
Oct-11	0.24%	0.17%	69%
Nov-11	0.25%	0.18%	70%
Dec-11	0.28%	0.18%	62%
Jan-12	0.28%	0.18%	64%
Feb-12	0.25%	0.22%	86%
Mar-12	0.24%	0.20%	84%
Apr-12	0.24%	0.25%	104%

**Indicative Forward PCRB Variable Rates  
For Quarter End Periods for Year Ending December 31, 2023**

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR (b)/(a)
	(a)	(b)	
May-12	0.24%	0.22%	90%
Jun-12	0.24%	0.19%	78%
Jul-12	0.25%	0.17%	68%
Aug-12	0.24%	0.16%	68%
Sep-12	0.22%	0.18%	81%
Oct-12	0.21%	0.20%	93%
Nov-12	0.21%	0.20%	95%
Dec-12	0.21%	0.15%	71%
Jan-13	0.21%	0.10%	51%
Feb-13	0.20%	0.13%	63%
Mar-13	0.20%	0.13%	66%
Apr-13	0.20%	0.18%	92%
May-13	0.20%	0.18%	90%
Jun-13	0.19%	0.11%	57%
Jul-13	0.19%	0.08%	43%
Aug-13	0.18%	0.09%	47%
Sep-13	0.18%	0.09%	49%
Oct-13	0.17%	0.10%	61%
Nov-13	0.17%	0.13%	78%
Dec-13	0.17%	0.14%	82%
Jan-14	0.16%	0.12%	74%
Feb-14	0.16%	0.11%	74%
Mar-14	0.15%	0.11%	73%
Apr-14	0.15%	0.13%	87%
May-14	0.15%	0.12%	80%
Jun-14	0.15%	0.10%	67%
Jul-14	0.15%	0.09%	61%
Aug-14	0.16%	0.09%	61%
Sep-14	0.15%	0.09%	55%
Oct-14	0.15%	0.08%	55%
Nov-14	0.15%	0.09%	59%
Dec-14	0.16%	0.08%	50%
Jan-15	0.17%	0.06%	38%
Feb-15	0.17%	0.06%	36%
Mar-15	0.18%	0.06%	35%
Apr-15	0.18%	0.09%	50%
May-15	0.18%	0.15%	79%
Jun-15	0.19%	0.13%	69%
Jul-15	0.19%	0.10%	55%
Aug-15	0.20%	0.09%	46%
Sep-15	0.20%	0.09%	47%
Oct-15	0.19%	0.10%	50%
Nov-15	0.21%	0.09%	45%
Dec-15	0.35%	0.08%	24%
Jan-16	0.43%	0.09%	20%
Feb-16	0.43%	0.08%	20%
Mar-16	0.44%	0.19%	45%
Apr-16	0.44%	0.41%	94%
May-16	0.44%	0.41%	93%
Jun-16	0.45%	0.43%	95%
Jul-16	0.48%	0.43%	89%
Aug-16	0.51%	0.49%	96%
Sep-16	0.53%	0.71%	134%
Oct-16	0.53%	0.77%	146%
Nov-16	0.56%	0.58%	103%
Dec-16	0.71%	0.66%	93%
Jan-17	0.77%	0.69%	89%
Feb-17	0.78%	0.66%	84%
Mar-17	0.93%	0.71%	77%
Apr-17	0.99%	0.90%	91%
May-17	1.01%	0.82%	81%
Jun-17	1.17%	0.83%	71%
Jul-17	1.23%	0.85%	69%
Aug-17	1.23%	0.79%	65%
Sep-17	1.23%	0.87%	71%
Oct-17	1.24%	0.93%	75%
Nov-17	1.29%	0.96%	75%
Dec-17	1.49%	1.25%	84%
Jan-18	1.56%	1.35%	86%
Feb-18	1.60%	1.10%	69%
Mar-18	1.80%	1.32%	73%
Apr-18	1.90%	1.75%	92%
May-18	1.95%	1.46%	75%
Jun-18	2.07%	1.33%	64%

**Indicative Forward PCRB Variable Rates  
For Quarter End Periods for Year Ending December 31, 2023**

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR (b)/(a)
	(a)	(b)	
Jul-18	2.08%	1.10%	53%
Aug-18	2.07%	1.53%	74%
Sep-18	2.18%	1.56%	72%
Oct-18	2.29%	1.60%	70%
Nov-18	2.32%	1.69%	73%
Dec-18	2.45%	1.70%	69%
Jan-19	2.51%	1.43%	57%
Feb-19	2.49%	1.64%	66%
Mar-19	2.49%	1.67%	67%
Apr-19	2.48%	1.90%	77%
May-19	2.44%	1.72%	70%
Jun-19	2.40%	1.79%	74%
Jul-19	2.31%	1.45%	63%
Aug-19	2.17%	1.45%	67%
Sep-19	2.04%	1.48%	72%
Oct-19	1.88%	1.41%	75%
Nov-19	1.74%	1.18%	68%
Dec-19	1.75%	1.34%	77%
Jan-20	1.67%	1.10%	66%
Feb-20	1.64%	1.21%	74%
Mar-20	0.92%	2.68%	292%
Apr-20	0.68%	0.85%	124%
May-20	0.19%	0.27%	139%
Jun-20	0.18%	0.19%	102%
Jul-20	0.17%	0.21%	125%
Aug-20	0.16%	0.17%	106%
Sep-20	0.15%	0.16%	108%
Oct-20	0.15%	0.17%	116%
Nov-20	0.14%	0.17%	121%
Dec-20	0.15%	0.15%	100%
Jan-21	0.13%	0.11%	85%
Feb-21	0.11%	0.06%	56%
Mar-21	0.11%	0.07%	70%
Apr-21	0.11%	0.10%	91%
May-21	0.10%	0.11%	113%
Jun-21	0.09%	0.07%	76%
Jul-21	0.09%	0.05%	54%
Aug-21	0.09%	0.04%	46%
Sep-21	0.08%	0.04%	50%
Oct-21	0.09%	0.08%	92%
Nov-21	0.09%	0.08%	89%
Dec-21	0.10%	0.11%	106%
Average			85%

	Forward 1 Mo BSBY Index*	Historical Floating Rate PCRB / 30 Day LIBOR	Forecast Floating Rate PCRB
	(1)	(2)	(1) * (2)
12/31/2022	0.94%	85%	0.801%
3/31/2023	1.16%	85%	0.985%
6/30/2023	1.36%	85%	1.153%
9/30/2023	1.56%	85%	1.323%
12/31/2023	1.57%	85%	1.338%
5QE Ave			1.120%

\* Source: Bloomberg L.P. (1/4/22)

Docket No. UE 399  
Exhibit PAC/206  
Witness: Nikki L. Koblaha

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Nikki L. Koblaha  
Cost of Preferred Stock**

**March 2022**

**PACIFICORP**  
**Electric Operations**  
**Cost of Preferred Stock**  
**12 Months Ended December 31, 2023**

Line No.	Description of Issue (1)	Issuance Date (2)	Call Price (3)	Annual Dividend Rate (4)	Shares O/S (5)	Total Par or Stated Value O/S (6)	Net Premium & (Expense) (7)	Net Proceeds to Company (8)	% of Gross Proceeds (9)	Cost of Money (10)	Annual Cost (11)	Line No.
1	<b>Serial Preferred, \$100 Par Value</b>											1
2	7.00% Series	(a)	None	7.000%	18,046	\$1,804,600	(b)	\$1,804,600	100.000%	7.000%	\$126,322	2
3	6.00% Series	(a)	None	6.000%	5,930	\$593,000	(b)	\$593,000	100.000%	6.000%	\$35,580	3
4												4
5	<b>Total Cost of Preferred Stock</b>			<u>6.753%</u>	<u>23,976</u>	<u>\$2,397,600</u>	<u>\$0</u>	<u>\$2,397,600</u>		<u>6.753%</u>	<u>\$161,902</u>	5
6												6
7												7
8	(a) These issues replaced an issue of The California Oregon Power Company as a result of the merger of that Company into Pacific Power & Light Co.											8
9	(b) Original issue expense/premium has been fully amortized or expensed.											9
10												10

Docket No. UE 399  
Exhibit PAC/300  
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Direct Testimony of Ann E. Bulkley**

**March 2022**



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## ATTACHED EXHIBITS

Exhibit PAC/301—Resume and Testimony Listing of Ann E. Bulkley

Exhibit PAC/302—Summary of Results

Exhibit PAC/303—Proxy Group Selection

Exhibit PAC/304—Constant Growth Discounted Cash Flow Model

Exhibit PAC/305—Multi-Stage Discounted Cash Flow Model

Exhibit PAC/306—Gross Domestic Product Growth

Exhibit PAC/307—Capital Asset Pricing Model

Direct Testimony of Ann E. Bulkley

Exhibit PAC/308—Risk Premium Approach

Exhibit PAC/309—Capital Expenditures Analysis

Exhibit PAC/310—Regulatory Risk Analysis

Exhibit PAC/311—Capital Structure Analysis

**I. INTRODUCTION AND QUALIFICATIONS**

1  
2 **Q. Please state your name and business address.**

3 A. My name is Ann E. Bulkley. I am a Principal at The Brattle Group (Brattle). My  
4 business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

5 **Q. What is your position with The Brattle Group?**

6 A. I am employed by Brattle as a Principal.

7 **Q. On whose behalf are you submitting this direct testimony?**

8 A. I am submitting this direct testimony before the Public Utility Commission of Oregon  
9 (Commission) on behalf of PacifiCorp d/b/a/ Pacific Power (PacifiCorp or the  
10 Company), which is an indirect wholly owned subsidiary of Berkshire Hathaway  
11 Energy Company (BHE).

12 **Q. Please describe your background and professional experience in the energy and**  
13 **utility industries.**

14 A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a  
15 Master's degree in Economics from Boston University, with over 25 years of  
16 experience consulting to the energy industry. I have advised numerous energy and  
17 utility clients on a wide range of financial and economic issues with primary  
18 concentrations in valuation and utility rate matters. Many of these assignments have  
19 included the determination of the cost of capital for valuation and ratemaking  
20 purposes. My resume and a summary of testimony that I have filed in other  
21 proceedings are included as Exhibit PAC/301 to this testimony.

1 **Q. Have you previously testified before the Commission or other regulatory**  
2 **authorities?**

3 A. Yes. A list of proceedings in which I have provided testimony is provided in  
4 Exhibit PAC/301 to this testimony.

5 **II. PURPOSE AND OVERVIEW OF TESTIMONY**

6 **Q. What is the purpose of your direct testimony?**

7 A. The purpose of my direct testimony is to present evidence and provide a  
8 recommendation regarding the appropriate Return on Equity (ROE)<sup>1</sup> for PacifiCorp's  
9 electric utility operations in Oregon and to provide an assessment of its proposed  
10 capital structure to be used for ratemaking purposes. A summary of my ROE  
11 analyses and results is provided in Exhibit PAC/302. My analysis and  
12 recommendations are supported by the data presented in Exhibit PAC/303 through  
13 Exhibit PAC/311, which were prepared by me or under my direction.

14 **Q. Please provide a brief overview of the analyses that led to your ROE**  
15 **recommendation.**

16 A. As discussed in more detail in Section VII, I applied the Constant Growth, Multi-  
17 Stage, and Projected forms of the Discounted Cash Flow (DCF) model, the Capital  
18 Asset Pricing Model (CAPM), and the Bond Yield Plus Risk Premium approach. My  
19 recommendation also takes into consideration: (1) PacifiCorp's capital expenditure  
20 requirements; (2) the regulatory environment in which PacifiCorp operates;  
21 (3) PacifiCorp's adjustment mechanisms; and (4) the fuel sources of PacifiCorp's  
22 generation portfolio.

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<sup>1</sup> Throughout my direct testimony, I interchangeably use the terms "ROE" and "cost of equity".

1           Finally, I considered PacifiCorp's proposed capital structure as compared to  
2           the capital structures of the proxy companies.<sup>2</sup> While I did not make any specific  
3           adjustments to my ROE estimates for any of these factors, I did take them into  
4           consideration in aggregate when determining where PacifiCorp's ROE falls within  
5           the range of analytical results.

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

7   A.   Section III provides a summary of my analyses and conclusions. Section IV reviews  
8           the regulatory guidelines pertinent to the development of the cost of capital.

9           Section V discusses current and prospective capital market conditions and the effect  
10          of those conditions on PacifiCorp's cost of equity. Section VI explains my selection  
11          of a proxy group of electric utilities. Section VII describes my analyses and the  
12          analytical basis for the recommendation of the appropriate ROE for PacifiCorp.

13          Section VIII provides a discussion of specific business and financial risks that have a  
14          direct bearing on the ROE to be authorized for PacifiCorp in this case. Section IX  
15          discusses PacifiCorp's capital structure as compared with the capital structures of the  
16          utility operating company subsidiaries of the proxy group companies. Section X  
17          presents my conclusions and recommendations.

18                   **III.   SUMMARY OF ANALYSES AND CONCLUSIONS**

19   **Q.   What is your recommended ROE for PacifiCorp?**

20   A.   Based on the analytical results in Figure 1 below, I believe a range from 9.90 percent  
21          to 10.75 percent is reasonable. The Company is requesting a return of 9.80 percent.

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<sup>2</sup> The selection and purpose of developing a group of comparable companies is discussed in detail in Section VI of my direct testimony.

1 This request considers the range of results for the proxy group companies, the relative  
2 business, financial, and regulatory risks of PacifiCorp's electric operations in Oregon  
3 as compared to the proxy group, and current capital market conditions and balances  
4 the interests of customers and shareholders.

5 **Q. Please summarize the key factors considered in your analyses and upon which you**  
6 **base your recommended ROE.**

7 A. My analyses and recommendations considered the following:

- 8 • The United States (U.S.) Supreme Court's *Hope* and *Bluefield* decisions,<sup>3</sup> which  
9 established the standards for determining a fair and reasonable authorized ROE,  
10 including consistency of the authorized return with other businesses having similar  
11 risk, adequacy of the return to ensure access to capital and support credit quality,  
12 and the necessity for the end result to lead to just and reasonable rates.
- 13 • The required ROE should be a forward-looking estimate; therefore, the analyses  
14 supporting my recommendation rely on forward-looking inputs and assumptions  
15 (e.g., forecasted growth rates in the DCF model, projected interest rates and a  
16 forward-looking market risk premium in the CAPM.).
- 17 • The effect of current and prospective capital market conditions on the ROE  
18 estimation models and on investors' return requirements.
- 19 • PacifiCorp's business risks relative to the proxy group companies and the  
20 implications of those risks in arriving at the appropriate ROE.

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<sup>3</sup> *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692-93 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

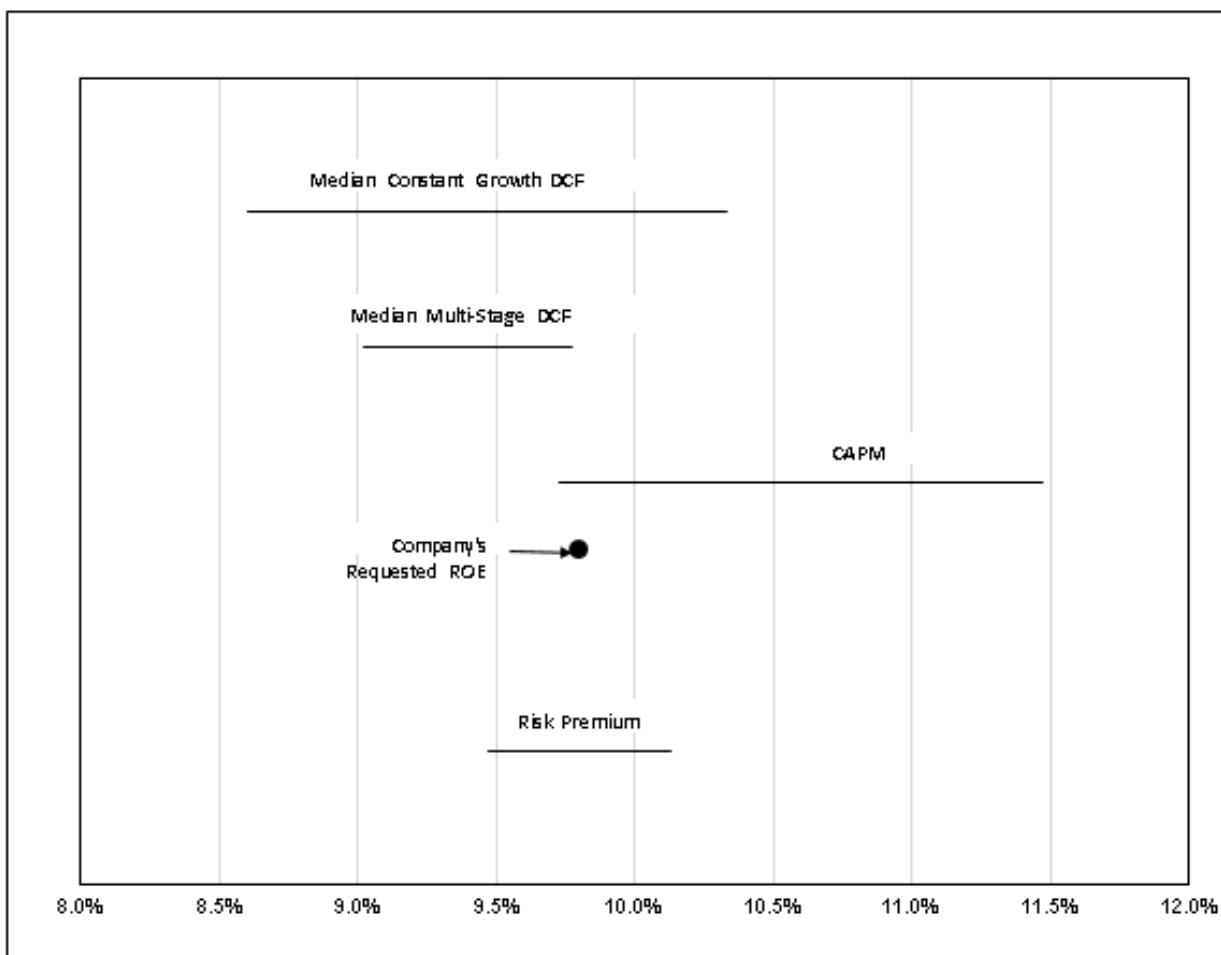
1 **Q. Please explain how you considered those factors.**

2 A. I relied on the results of several analytical approaches to estimate PacifiCorp's cost of  
3 equity based on a proxy group of publicly-traded companies. As shown in Figure 1,  
4 those ROE estimation models produce a wide range of results. My conclusion about  
5 where within that range of results PacifiCorp's ROE should be placed is based on  
6 PacifiCorp's business and financial risk relative to the proxy group. Although the  
7 companies in my proxy group are generally comparable to PacifiCorp, each company  
8 is unique and no two companies have the exact same business and financial risk  
9 profiles. Accordingly, I selected a proxy group with similar, but not identical risk  
10 profiles, and I adjusted the results of my analysis either upward or downward within  
11 the reasonable range of results to account for any residual differences in risk.

12 **Q. Please summarize the ROE estimation models that you considered to establish  
13 the range of ROEs for PacifiCorp's Oregon operations.**

14 A. I considered the results of two forms of the DCF model; the Constant Growth DCF,  
15 and the Multi-Stage DCF. In addition, I considered the results of the CAPM, and  
16 Risk Premium. The results of these analyses are summarized in Figure 1 below.

**Figure 1: Summary of Analytical Results**



1 As shown in Figure 1, the range of results produced by the Constant Growth DCF  
 2 estimation model is relatively wide, particularly in relation to the results of the other  
 3 methodologies. While it is common to consider multiple models to estimate the cost  
 4 of equity, it is particularly important when the range of results varies considerably  
 5 across methodologies.

6 Furthermore, as shown in Exhibit PAC/304, the median results of both the  
 7 Constant Growth and Multi-Stage DCF analyses using the earnings lowest growth  
 8 rates for each of the proxy group companies produce results that are below recently



1 authorized ROEs for electric utilities in the U.S. that are relying on traditional  
2 original cost ratemaking. Therefore, I conclude that these results do not provide a  
3 sufficient risk premium to compensate equity investors for the residual risks of  
4 ownership, including the risk that they have the lowest claim on the assets and  
5 income of PacifiCorp.

6 Although I have concerns about the results produced by the DCF models, my  
7 ROE recommendation considers the range between the median and median-high  
8 results of the DCF models. In addition, I consider the results of forward-looking  
9 CAPM and a Bond Yield Plus Risk Premium analysis. I also consider company-  
10 specific risk factors, and current and prospective capital market conditions.

11 As I will discuss, expected changes in capital market conditions will affect the  
12 results of the ROE estimation models, making it important to review results based on  
13 historical or current data recognizing that these conditions may not represent the  
14 forward-looking cost of equity. The assumptions in each of the models are affected  
15 differently. In determining the appropriate forward-looking ROE, it is important to  
16 recognize these limitations in the static models and consider how the results may  
17 differ during the period over which the rates in this proceeding will be in effect. For  
18 example, dividend yields in the DCF model are affected by the recent historical high  
19 stock prices. As accommodative monetary policies begin to be reversed, it is  
20 reasonable to expect that utility stocks will underperform the broader market. Lower  
21 stock prices increasing dividend yields on utility stocks and all else equal, would  
22 increase the ROE resulting from the DCF model. Further, the Federal Reserve has  
23 signaled its intention to increase interest rates. Increases in interest rates are likely to

1 affect the bond yields used in the CAPM. Therefore, it would be reasonable to  
2 consider scenarios of this model that reflect changes in bond yields.

3 **Q. Please summarize the analysis you conducted in determining that PacifiCorp's**  
4 **requested capital structure is reasonable and appropriate.**

5 A. Based on the analysis presented in Section IX of my direct testimony, I conclude that  
6 PacifiCorp's proposed common equity ratio of 52.25 percent is reasonable. To make  
7 this determination, I reviewed the capital structures of the utility operating  
8 subsidiaries of the proxy companies. As shown in Exhibit PAC/311, the results of  
9 that analysis demonstrate that the equity ratios for the utility operating companies  
10 held by the proxy group range from 46.85 percent to 61.11 percent with a median of  
11 52.71 percent. PacifiCorp's proposed common equity ratio of 52.25 percent is well  
12 within the range established for the utility operating subsidiaries of the proxy group  
13 companies and is reasonable.

14 Furthermore, a fundamental aspect of the financial regulation of utilities is  
15 assuring that the subject utility has a reasonable opportunity to earn a return on capital  
16 consistent with the return available on investments of similar risk. While this  
17 principle is most often discussed in terms of the allowed ROE, it is equally applicable  
18 to all aspects of the overall Rate of Return (ROR). The equity return, which is the  
19 product of the ROE and the equity ratio, (*i.e.*, the Weighted Return on Equity  
20 (WROE)), ultimately defines the return to shareholders, and the product of the cost of  
21 debt and the debt ratio ensures that a company's debt obligations are met.

22 Therefore, it is necessary to consider both the rates that are applied to debt and equity  
23 and the composition of the capital structure to determine the reasonableness of the

1 ROR. Taken together, PacifiCorp's proposed common equity ratio of 52.25 percent  
2 and its requested ROE of 9.80 percent, result in a WROE of 5.12 percent. This return  
3 reasonably balances the interests of customers and shareholders by enabling  
4 PacifiCorp to maintain its financial integrity and therefore its ability to attract capital  
5 at reasonable terms and conditions under a variety of economic and financial market  
6 conditions.

7 **IV. REGULATORY GUIDELINES**

8 **Q. Please describe the principles that guide the establishment of the cost of capital**  
9 **for a regulated utility.**

10 A. The U.S. Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the  
11 standards for determining the fairness or reasonableness of a utility's authorized  
12 ROE. Among the standards established by the Court in those cases are: (1)  
13 consistency with other businesses having similar or comparable risks; (2) adequacy of  
14 the return to support credit quality and access to capital; and (3) the principle that the  
15 specific means of arriving at a fair return are not important, only that the end result  
16 leads to just and reasonable rates.<sup>4</sup>

17 **Q. Has the Commission provided similar guidance in establishing the appropriate**  
18 **return on common equity?**

19 A. Yes. The Commission follows the precedents of the *Hope* and *Bluefield* cases by  
20 acknowledging that utility investors are entitled to a fair and reasonable return. For  
21 example, in the Company's last rate determination the Commission stated:

22 In establishing fair and reasonable rates under ORS 756.040, we  
23 balance the interests of the utility investor and customers by

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<sup>4</sup> *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

1 ensuring that the rates provide adequate revenue both for operating  
2 expenses and for capital costs of the utility, with a return to the  
3 equity holder that is “commensurate with the return on investments  
4 in other enterprises having corresponding risks” and “sufficient to  
5 ensure confidence in the financial integrity of the utility, allowing  
6 the utility to maintain its credit and attract capital.”<sup>5</sup>

7 This guidance is in accordance with the *Hope* and *Bluefield* decisions and the  
8 principles that I employed to estimate the ROE for PacifiCorp, including the principle  
9 that an allowed ROR must be sufficient to enable regulated companies like  
10 PacifiCorp to attract capital on reasonable terms.

11 **Q. Why is it important for a utility to be allowed the opportunity to earn a return  
12 that is adequate to attract capital at reasonable terms?**

13 A. An ROE that is adequate to attract capital at reasonable terms enables a utility to  
14 continue to provide safe, reliable service while maintaining its financial integrity. To  
15 the extent that the utility is provided the opportunity to earn its market-based cost of  
16 capital, neither customers nor shareholders are disadvantaged.

17 **Q. What are your conclusions regarding regulatory guidelines?**

18 A. The ratemaking process is premised on the principle that, in order for investors and  
19 companies to commit the capital needed to provide safe and reliable utility services, a  
20 utility must have the opportunity to recover the return of, and the market-required  
21 return on, its invested capital. Because utility operations are capital-intensive,  
22 regulatory decisions should enable the utility to attract capital at reasonable terms;  
23 doing so balances the long-term interests of the utility and its customers.

24 The financial community carefully monitors the current and expected

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<sup>5</sup> *In the Matter of PacifiCorp, dba Pacific Power, request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 6 (Dec. 18, 2020).

1 financial condition of utility companies and the regulatory framework in which they  
2 operate. In that respect, the regulatory framework is one of the most important  
3 factors in both debt and equity investors' assessments of risk. The Commission's  
4 order in this proceeding, therefore, should establish rates that provide PacifiCorp with  
5 the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable  
6 terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with  
7 returns on investments in enterprises with similar risk. To the extent that PacifiCorp  
8 is authorized the opportunity to earn its market-based cost of capital, the proper  
9 balance is achieved between customers' and shareholders' interests.

## 10 V. CAPITAL MARKET CONDITIONS

### 11 Q. Why is it important to analyze capital market conditions?

12 A. The ROE estimation models rely on market data that are either specific to the proxy  
13 group, in the case of the DCF model, or to the expectations of market risk, in the case  
14 of the CAPM. The results of the ROE estimation models can be affected by  
15 prevailing market conditions at the time the analysis is performed. While the ROE  
16 that is established in a rate proceeding is intended to be forward-looking, the analyst  
17 uses current and projected market data, specifically stock prices, dividends, growth  
18 rates and interest rates, in the ROE estimation models to estimate the required return  
19 for the subject company.

20 As discussed in the remainder of this section, analysts and regulatory  
21 commissions have concluded that current market conditions have affected the results  
22 of the ROE estimation models. As a result, it is important to consider the effect of  
23 these conditions on the ROE estimation models when determining the appropriate

1 range and recommended ROE for a future period. If investors do not expect current  
2 market conditions to be sustained in the future, it is possible that the ROE estimation  
3 models will not provide an accurate estimate of investors' required return during that  
4 rate period. Therefore, it is very important to consider projected market data to  
5 estimate the return for that forward-looking period.

6 **Q. What factors are affecting the cost of equity for regulated utilities in the current  
7 and prospective capital markets?**

8 A. The cost of equity for regulated utility companies is being affected by several factors  
9 in the current and prospective capital markets, including: (1) the dramatic shifts in  
10 market conditions during 2020, (2) the economic recovery in 2021 and the currently  
11 high inflation and the expectations for rising interest rates and continued inflation in  
12 2022, and (3) the effect of these changes on the assumptions used in the ROE  
13 estimation models. In this section, I discuss each of these factors and how it affects  
14 the models used to estimate the cost of equity for regulated utilities.

15 **Q. What effect do current and prospective market conditions have on the cost of  
16 equity for PacifiCorp?**

17 A. The economy is currently in the recovery phase of the business cycle. During the  
18 recovery phase, interest rates and inflation are expected to increase. In fact, inflation  
19 is currently at its highest level seen in approximately 40 years while interest rates  
20 have increased from the pandemic lows seen in 2020. Utilities, which are a defensive  
21 sector, have historically underperformed the market during periods of economic  
22 expansion. Therefore, investors are currently expecting utilities to underperform over  
23 the near-term, which means the share prices of utilities will likely decline. A decline

1 in share prices will increase the dividend yields of utilities and thus the cost of equity  
2 for utilities is expected to increase over the near-term. This is important because the  
3 cost of equity in this proceeding is being estimated for the period that PacifiCorp's  
4 rates will be in effect. Since the cost of equity is expected to increase over the near-  
5 term for utilities, ROE estimates based on current market conditions will understate  
6 the ROE during the period that the Company's rates will be in effect. For example,  
7 the DCF model, which relies on historical averages of share prices, is likely to  
8 understate the cost of equity for PacifiCorp over the near term.

9 **Q. Do recent economic projections indicate the expectation for a continued strong**  
10 **economic recovery in 2022?**

11 A. Yes. Economic data beginning in mid-2021 had been indicating the expectation for  
12 strong economic recovery and inflationary pressure in response to that recovery. The  
13 Federal Open Market Committee (FOMC), which is composed of 12 members  
14 including the Board of Governors of the Federal Reserve system and presidents of the  
15 Federal Reserve Banks, reviews economic and financial conditions, determines the  
16 appropriate stance for monetary policy and assesses the risks to its long-run goals of  
17 price stability and economic growth. The FOMC issued its Summary of Economic  
18 Projections in December 2021, where the FOMC's median projection for Gross  
19 Domestic Product (GDP) growth from Q4 2021 to Q4 2022 is 4.0 percent.<sup>6</sup> Several  
20 months prior to the FOMC guidance, issued in December 2021, the Congressional  
21 Budget Office (CBO) issued an update to its outlook on economic conditions on  
22 July 1, 2021. In that report, the CBO projected strong GDP growth for 2021 and

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<sup>6</sup> Federal Open Market Committee, Summary of Economic Projections at 2 (Dec. 15, 2021).

1 beyond, and significant strength in overall economic conditions including:

- 2 • Real GDP growth of 7.4 percent in 2021 and 3.1 percent in 2022, which is a  
3 significant change from the negative 2.4 percent growth rate in 2020;
- 4 • Inflation indicators at or above the 2.0 percent threshold in 2021 and continuing  
5 through 2031;
- 6 • Labor force expected to be restored to pre-pandemic levels in 2022; and
- 7 • Interest rates on federal borrowing increasing through 2031.<sup>7</sup>

8 These trends indicate strong economic recovery over the next year, with robust  
9 consumer spending expected.

10 **Q. Please summarize the monetary policy actions of the Federal Reserve in**  
11 **response to the COVID-19 pandemic.**

12 A. In response to the COVID-19 pandemic, the Federal Reserve:

- 13 • decreased the Federal Funds rate twice in March 2020, resulting in a target range  
14 of 0.00 percent to 0.25 percent.
- 15 • increased its holdings of both Treasury and mortgaged-back securities.
- 16 • started expansive programs to support credit to large employers—the Primary  
17 Market Corporate Credit Facility to provide liquidity for new issuances of corporate  
18 bonds; and the Secondary Market Corporate Credit Facility to provide liquidity for  
19 outstanding corporate debt issuances; and
- 20 • supported the flow of credit to consumers and businesses through the Term Asset-  
21 Backed Securities Loan Facility.

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<sup>7</sup> Congressional Budget Office, An Update to the Budget and Economic Outlook 2021 to 2031, July 2021.



1           In addition, Congress passed the Coronavirus Aid, Relief, and Economic  
2           Security Act in March 2020, the Consolidated Appropriations Act in December 2020  
3           and the American Rescue Plan Act in March 2021, which included \$2.2 trillion,  
4           \$900 billion and \$1.9 trillion, respectively, in fiscal stimulus aimed at also mitigating  
5           the economic effects of COVID-19. These expansive monetary and fiscal programs  
6           mitigated the economic effects of the COVID-19 pandemic and are currently  
7           providing additional support as the economy recovers from the COVID-19 recession.

8   **Q.    Are there indications that the Federal Reserve is normalizing monetary policy?**

9   A.    Yes. At its December 15, 2021 meeting, the Federal Reserve decided to increase the  
10       pace of its taper of bond purchases in response to inflation exceeding its target of  
11       2 percent for a sustained period of time. Beginning in January 2022, the Federal  
12       Reserve will reduce asset purchases of Treasuries by \$20 billion and mortgage-  
13       backed securities by \$10 billion on a monthly basis.<sup>8</sup> This change is double the initial  
14       plan outlined at the Federal Reserve’s November 2, 2021 meeting which called for  
15       reducing asset purchases of Treasuries by \$10 billion and mortgage-backed securities  
16       by \$5 billion on a monthly basis.<sup>9</sup> At that time, the Federal Reserve’s FOMC was  
17       forecasting three increases in the federal funds rate by the end of 2022,<sup>10</sup> which was a  
18       substantial increase from the one increase that was forecasted by the FOMC at the  
19       September 22, 2021 meeting.<sup>11</sup>

20   **Q.    Why has the Federal Reserve decided to normalize monetary policy?**

21   A.    The Federal Reserve has accelerated plans to normalize monetary policy in response

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<sup>8</sup> Press Release, Federal Reserve (Dec. 15, 2021).

<sup>9</sup> Press Release, Federal Reserve (Nov. 3, 2021).

<sup>10</sup> Summary of Economic Projections, Federal Reserve (Dec. 15, 2021).

<sup>11</sup> Summary of Economic Projections, Federal Reserve (Sept. 22, 2021).

1 to increasing inflation. While the Federal Reserve initially viewed inflation as  
2 transitory, it has been higher and more persistent than the target levels and is expected  
3 to continue in 2022. Specifically, Federal Reserve Chairman Jerome Powell stated:

4 We are phasing out our purchases more rapidly because with  
5 elevated inflation pressures and a rapidly strengthening labor market  
6 the economy no longer needs increasing amounts of policy  
7 support.<sup>12</sup>

8 Since December 2021, the Federal Reserve has indicated in a number of  
9 statements that it intends to respond to rising inflation with increases in interest rates.  
10 Most recently, on January 11, 2022, in a hearing before the Senate Banking  
11 Committee, Federal Reserve Chairman Powell stated that he expects inflation to  
12 persist into mid-2022. Further, Chairman Powell noted that if inflation persists at  
13 high levels, the Federal Reserve will be prepared to respond by raising interest rates  
14 and beginning to taper bond purchases “sooner and faster” than in prior circumstances  
15 where there was a need to taper. In addition, he noted that the economy no longer  
16 required aggressive stimulus and that the Federal Reserve would start to revert to the  
17 interest rates maintained before the pandemic.<sup>13</sup>

18 In fact, Goldman Sachs recently noted that it expects the Federal Reserve to  
19 increase the federal funds rate four times in 2022 in response to rising inflation as  
20 opposed to the December 2021 projection of three increases by the Federal Reserve.<sup>14</sup>

21 Further, the former New York Federal Reserve President, William Dudley, suggested

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<sup>12</sup> FOMC Meeting Press Conference, Transcript of Chair Powell’s Opening Statement (Dec. 15, 2021), at 4.

<sup>13</sup> Barron’s, Powell Says Balance Sheet Run-Off Maybe Later This Year, Inflation to Persist into Mid-2022, January 11, 2022.

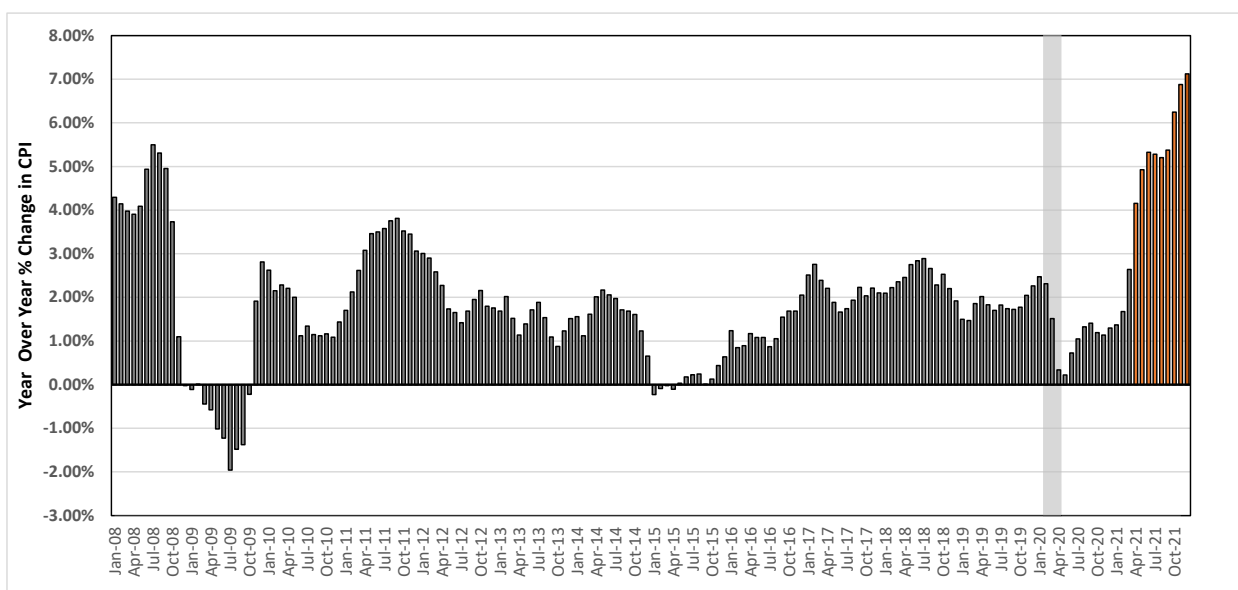
<sup>14</sup> Callum Keown, *Bond Yields Keep Rising. Goldman Sachs Now Sees 4 Rate Hikes in 2022*. Barron's, (Jan. 10, 2022) available at [https://www.barrons.com/articles/things-to-know-today-51641808668?mod=BRNS\\_ENG\\_NAS\\_EML\\_BULLETIN\\_AUTO\\_NAH%3Fmod](https://www.barrons.com/articles/things-to-know-today-51641808668?mod=BRNS_ENG_NAS_EML_BULLETIN_AUTO_NAH%3Fmod).

1 that the Federal Reserve may even need to raise rates five times in 2022.<sup>15</sup>

2 **Q. Is the increase in inflation significant?**

3 A. Yes. As shown in Figure 2, the year-over-year (YOY) change in the Consumer Price  
4 Index (CPI) published by the Bureau of Labor Statistics has increased steadily in  
5 2021 rising from 1.37 percent in January to 7.12 percent in December. The  
6 7.12 percent YOY in the CPI in December 2021 is the largest 12-month increase  
7 since 1982 and is significantly greater than any level seen since January 2008.

8 **Figure 2: CPI YOY Percent Change, January 2008 – December 2021<sup>16</sup>**



9 **Q. What are the expectations for inflation over the near-term?**

10 A. Investors expect inflation to persist into 2022. For example, Goldman Sachs forecasts  
11 consumer price inflation excluding food and energy costs to still be above 4 percent  
12 when the Federal Reserve ends their tapering of bond purchases in 2022.<sup>17</sup> Similarly,

<sup>15</sup> Callum Keown, Powell’s Senate Hearing Holds the Key for Markets. Expect the Unexpected, (Jan. 11, 2022).

<sup>16</sup> Bureau of Labor Statistics, shaded area indicates the COVID-19 pandemic recession.

<sup>17</sup> Simon Kennedy, *Goldman Now Sees Fed Hiking Rates in July as Inflation Lingers*. Bloomberg.com, Bloomberg (Oct. 30, 2021) available at <https://www.bloomberg.com/news/articles/2021-10-30/goldman-now-sees-fed-hiking-rates-in-july-as-inflation-lingers>.

1 respondents to the recent CNBC Fed Survey, indicated the CPI is expected to rise  
2 4.0 percent in 2022 and 3.0 percent in 2023 which is well above the Federal  
3 Reserve's long-term target of 2 percent.<sup>18</sup> Finally, Kiplinger recently noted the  
4 following regarding inflation expectations over the near-term:

5 While the inflation rate is expected to drop as the year progresses,  
6 this month's price report is likely to get the Federal Reserve to make  
7 its first interest rate hike in four years in March, with three more  
8 hikes after that (in June, September and December). While the Fed  
9 believes that inflation will fall, it is concerned that today's rising  
10 costs may become a self-fulfilling prophecy, as businesses expect to  
11 be able to continue raising prices, and workers continue to expect  
12 rising wages.<sup>19</sup>

13 **Q. What effect will inflation have on long-term interest rates?**

14 A. Inflation and the Federal Reserve's normalization of monetary policy will likely  
15 result in increases in long-term interest rates. Specifically, inflation reduces the  
16 purchasing power of the future interest payments an investor expects to receive over  
17 the duration of the bond. This risk increases the longer the duration of the bond. As a  
18 result, if investors expect increased levels of inflation, they will require higher yields  
19 to compensate for the increased risk of inflation which means interest rates will likely  
20 increase.

21 **Q. What views have equity analysts expressed about the economic conditions and  
22 the yields on long-term government bonds over the near-term?**

23 A. Several equity analysts have noted that they expect economic conditions to continue  
24 to improve and thus the yields on long-term government bonds to continue to increase

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<sup>18</sup> Steve Liesman, *The Fed will halt asset purchases by March and hike rates in June, CNBC survey predicts*. CNBC, (Dec. 14, 2021) available at <https://www.cnbc.com/2021/12/14/the-fed-will-halt-asset-purchases-by-march-and-hike-rates-in-june-cnbc-survey-predicts.html>.

<sup>19</sup> David Payne, *Inflation Stays Hot for Now*, Kiplinger (Jan. 13, 2022).

1 through the end of 2022. As shown in Figure 3, according to six different equity  
 2 analysts, the yield on the 10-year Treasury Bond is expected to range from  
 3 1.75 percent to 2.50 percent in 2022, which is 26 to 101 basis points greater than the  
 4 current 30-day average yield on the 10-year Treasury Bond as of December 31, 2021,  
 5 of 1.49 percent. Specifically, Morgan Stanley recently noted the following regarding  
 6 the expectation for long-term government bond yields in 2022:

7 Continued strong growth in 2022, alongside receding but above-  
 8 target inflation, keeps the Fed patient, yet gradually moving toward  
 9 rate hikes, and keeps Treasury yields moving higher.<sup>20</sup>

10 **Figure 3: Equity Analysts Forecast of the 10-year Treasury Yield<sup>21</sup>**

Bank	10-year U.S. Treasury Yield	
	30-day Average as of December 31, 2021	2022 Forecast
Barclays	1.49%	1.75%
Morgan Stanley	1.49%	2.10%
Goldman Sachs	1.49%	2.00%
JP Morgan	1.49%	2.10%
Wells Fargo Investment Institute	1.49%	2.00% - 2.50%
Amundi	1.49%	1.80% - 2.00%

11 **Q. Have you considered any additional indicators that may imply long-term interest**  
 12 **rates are expected to increase?**

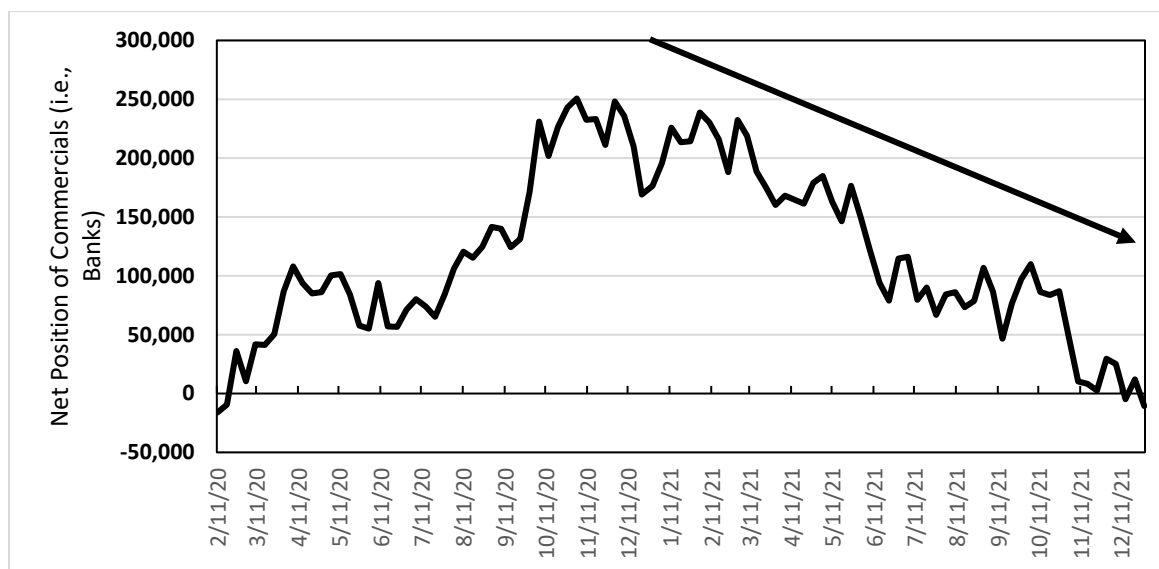
13 A. Yes; I considered the net position of commercials (*i.e.*, banks) in U.S. Treasury Bond  
 14 futures contracts as reported in the Commitment of Traders Report produced by the  
 15 Commodity Futures Trading Commission. A net position is defined as the total  
 16 number of long positions in a futures contract minus the total number of short

<sup>20</sup> Factbox: Wall Street Forecasts for the U.S. Dollar and 10-Year Treasury Yield in 2022., Reuters, Thomson Reuters (Nov. 18, 2021) available at <https://www.reuters.com/markets/us/wall-street-forecasts-us-dollar-10-year-treasury-yield-2022-2021-11-18/>

<sup>21</sup> Factbox: Wall Street Forecasts for the U.S. Dollar and 10-Year Treasury Yield in 2022., Reuters, Thomson Reuters (Nov. 18, 2021) available at <https://www.reuters.com/markets/us/wall-street-forecasts-us-dollar-10-year-treasury-yield-2022-2021-11-18/>.

1 positions in a futures contract. A long position means that an investor agrees to  
 2 purchase an asset in the future at a specified price today and therefore profits if the  
 3 price of the underlying asset increases. Conversely, a short position is when an  
 4 investor agrees to sell an asset at a time in the future at a specified price today and  
 5 profits if the price of the asset declines. Therefore, if banks are increasing the number  
 6 of short positions and thus have a declining net position, the banks are assuming that  
 7 the price of the asset will decline. As shown in Figure 4, the net position of banks in  
 8 U.S. Treasury Bonds has been decreasing since the end of 2020. Therefore, banks are  
 9 forecasting a decrease in the price of long-term government bonds and thus are  
 10 projecting that the yields (which are inversely related to the price) will increase over  
 11 the near-term.

12 **Figure 4: Net Position of Commercials (i.e., Banks) in U.S. Treasury Bond Futures**  
 13 **Contracts<sup>22</sup>**



<sup>22</sup> Commitment of Traders Report, as of Dec. 31, 2021, available at <https://www.cftc.gov/MarketReports/CommitmentsofTraders/HistoricalCompressed/index.htm>

1 **Q. Are utility share prices correlated to changes in the yields on long-term**  
2 **government bonds?**

3 A. Yes; interest rates and utility share prices are inversely correlated, which means, for  
4 example, that an increase in interest rates will result in a decline in the share prices of  
5 utilities. For example, Goldman Sachs and Deutsche Bank recently examined the  
6 sensitivity of share prices of different industries to changes in interest rates over the  
7 past five years. Both Goldman Sachs and Deutsche Bank found that utilities had one  
8 of the strongest negative relationships with bond yields (*i.e.*, increases in bond yields  
9 resulted in the decline of utility share prices).<sup>23</sup> Charles Schwab also recently noted  
10 the inverse relationship between interest rates and utility share prices and concluded  
11 that the utility sector tends to underperform during periods of economic growth when  
12 interest rates are higher.<sup>24</sup>

13 **Q. How do equity analysts expect utilities to underperform in an increasing interest**  
14 **rate environment?**

15 A. Equity analysts project that utilities will continue to underperform the broader market  
16 as interest rates increase. For example, in a recent article, Barron's conducted its Big  
17 Money poll of professional investors regarding the outlook for the next 12 months.  
18 Approximately 60 percent of respondents projected the yield on the 10-year Treasury  
19 Bond will be 2.00 percent or greater at the end of the next 12 months which is an

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<sup>23</sup> Justina Lee, *Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks.*, Bloomberg.com (Mar. 11, 2021) available at <http://www.bloomberg.com/news/articles/2021-03-11/wall-street-is-rethinking-the-treasury-threat-to-big-tech-stocks>.

<sup>24</sup> Charles Schwab, *Schwab Sector Views: Too Early for Defensive Positioning* (Aug. 19, 2021).

1 increase from the current 30-day average 10-year Treasury Bond yield as of  
2 December 31, 2021 of 1.49 percent.<sup>25</sup>

3 Other equity analysts concur with this conclusion. Fidelity recently  
4 recommended underweighting the utility sector and noted that “[w]eak fundamentals  
5 and high valuations could be headwinds for utilities and real estate, especially if rates  
6 increase.”<sup>26</sup> In its 2022 Outlook, Wells Fargo classified the utility sector as “most  
7 unfavorable” as economic growth continues to rebound and interest rates increase.<sup>27</sup>  
8 Finally, Charles Schwab has classified the utilities sector overall as “Underperform,”  
9 noting negatives for the sector that include “interest rates are expected to recover  
10 from recent decline” and “economic recovery makes the sector less attractive, relative  
11 to other sectors.”<sup>28</sup>

12 **Q. What is the significance of the inverse relationship between interest rates and**  
13 **utility share prices in the current market relative to the cost of equity in this**  
14 **proceeding?**

15 A. As discussed above, the economy is currently in the recovery phase of the business  
16 cycle, which is characterized by improving economic growth, increasing inflation,  
17 and increasing interest rates. If interest rates increase as expected, then the share  
18 prices of utilities will decline. If the share prices of utility stocks decline, then the  
19 DCF model, which relies on historical averages of share prices, is likely to understate

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<sup>25</sup> Nicholas Jasinski, *Stocks Are Still the Place to Be, Our Exclusive Big Money Poll Finds.*, Barron’s (Oct. 16, 2021) available at <https://www.barrons.com/articles/stock-market-covid-economy-outlook-51634312012?mod=hpsubnav&tesla=y>.

<sup>26</sup> Fidelity, “Q4 2021 sector scorecard” (Oct. 27, 2021).

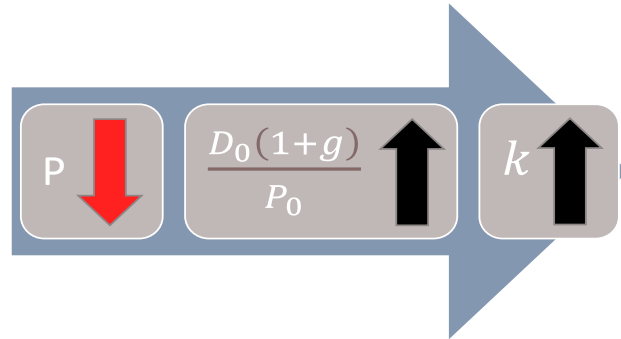
<sup>27</sup> Wells Fargo Investment Institute, 2022 Outlook (Dec. 2021).

<sup>28</sup> Charles Schwab, Utilities Sector Rating: Underperform (Dec. 16, 2021).



1 the cost of equity. Figure 5 summarizes the effect of price on the dividend yield in  
2 the Constant Growth DCF model.

3 **Figure 5: The Effect of a Decline in Stock Prices on the Constant Growth DCF Model**



4 A decline in utility stock prices going forward will increase the dividend  
5 yields of utility stocks and thus increase the estimate of the cost of equity that would  
6 be produced by the Constant Growth DCF model relative to the cost of equity  
7 currently produced by the Constant Growth DCF model that relies on historical stock  
8 prices. Therefore, this expected change in market conditions supports consideration  
9 of the range of ROE results produced by the mean to mean-high DCF results since the  
10 mean DCF results would likely understate the cost of equity during the period that the  
11 Company's rates will be in effect. Moreover, prospective market conditions warrant  
12 consideration of other ROE estimation models such as the CAPM, and Risk Premium  
13 which may better reflect expected market conditions. For example, two out of three  
14 inputs to the CAPM (*i.e.*, the market risk premium and risk-free rate) are forward-  
15 looking.

16 **Q. Have state regulatory commissions considered market events and the utility's  
17 ability to attract capital in determining the equity return?**

18 A. Yes. In a recent rate case for Consumers Energy Company, the Michigan Public

1 Service Commission (Michigan PSC) noted that it is important to consider how a  
2 utility's access to capital could be affected in the near-term as a result of market  
3 reactions to global events like those that have occurred in the recent past.<sup>29</sup>

4 Specifically, the Michigan PSC stated that:

5 [i]n setting the ROE at 9.90%, the Commission believes there is an  
6 opportunity for the company to earn a fair return during this period  
7 of atypical market conditions. This decision also reinforces the  
8 belief, as stated in the Commission's March 29 order, "that  
9 customers do not benefit from a lower ROE if it means the utility  
10 has difficulty accessing capital at attractive terms and in a timely  
11 manner." These conditions still hold true based on the evidence in  
12 the instant case. The fact that other utilities have been able to access  
13 capital despite lower ROEs, as argued by many intervenors, is also  
14 a relevant consideration. It is also important to consider how  
15 extreme market reactions to global events, as have occurred in the  
16 recent past, may impact how easily capital will be able to be  
17 accessed during the future test period should an unforeseen market  
18 shock occur. The Commission will continue to monitor a variety of  
19 market factors in future rate cases to gauge whether volatility and  
20 uncertainty continue to be prevalent issues that merit more  
21 consideration in setting the ROE.<sup>30</sup>

22 The Michigan PSC references "global events" and the overall effect the events  
23 could have on the ability of a utility to access capital. Consistent with the Michigan  
24 PSC's views, it is important to consider current market conditions and the impact of  
25 those conditions on the access to and cost of capital, and to position utilities to be able  
26 to maintain access in rapidly changing market conditions.

27 **Q. What are your conclusions regarding the effect of current and expected future**  
28 **capital market conditions on the cost of equity for the Company?**

29 **A.** Over the near-term, investors expect economic growth to continue to rebound and

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<sup>29</sup> In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief, Mich. Pub. Serv. Comm'n, Cause No. U-20697, Order at 165 (Dec. 17, 2020).

<sup>30</sup> *Id.* at 43 (emphasis added).

1 thus inflation and interest rates to increase. Because the share prices of utilities are  
 2 inversely correlated to the interest rates, an increase in long-term government bond  
 3 yields will likely result in a decline in utility share prices which is the reason a  
 4 number of equity analysts expect the utility sector to underperform over the near-  
 5 term. The expected underperformance of the utility sector relative to the broader  
 6 stock market means that DCF models using recent historical data likely underestimate  
 7 investors’ required return over the period that rates will be in effect. This change in  
 8 market conditions also support the use of other ROE estimation models such as the  
 9 CAPM, and Risk Premium which may better reflect expected market conditions.

**VI. PROXY GROUP SELECTION**

11 **Q. Why have you used groups of proxy companies to estimate the cost of equity for  
 12 PacifiCorp?**

13 **A.** In this proceeding, I am estimating the cost of equity for PacifiCorp, a rate-regulated  
 14 subsidiary of BHE. Since the ROE is a market-based concept and given the fact  
 15 PacifiCorp’s operations in Oregon do not make up the entirety of a publicly-traded  
 16 entity, it is necessary to establish a group of companies that is both publicly-traded  
 17 and comparable to PacifiCorp in certain fundamental business and financial respects  
 18 to serve as its “proxy” for purposes of estimating the cost of equity.

19 Even if PacifiCorp’s Oregon electric utility operations made up the entirety of  
 20 a publicly-traded entity, it is possible that transitory events could bias its market value  
 21 over a given time period. A significant benefit of using a proxy group is that it  
 22 mitigates the effects of anomalous events that may be associated with any one  
 23 company. The proxy companies used in my analyses all possess a set of operating

1 and financial risk characteristics that are substantially comparable to PacifiCorp, and,  
2 therefore, provide a reasonable basis to derive and estimate the appropriate ROE for  
3 the Company.

4 **Q. Please provide a brief profile of PacifiCorp.**

5 A. PacifiCorp is an indirect, wholly owned subsidiary of BHE. PacifiCorp provides  
6 electric utility service to approximately 2.0 million residential, commercial and  
7 industrial customers in California, Idaho, Oregon, Utah, Washington, and  
8 Wyoming.<sup>31</sup> In Oregon, PacifiCorp provides electric service to approximately  
9 630,000 residential, commercial, and industrial customers.<sup>32</sup> As of December 31,  
10 2021, PacifiCorp owned net utility electric plant of approximately \$22.4 billion.<sup>33</sup>  
11 PacifiCorp's electric operations in Oregon represented 23.8 percent of PacifiCorp's  
12 electric sales in 2020.<sup>34</sup> PacifiCorp currently has an investment grade long-term  
13 rating of A(Outlook: Stable) from Standard & Poor's (S&P) and A3 (Outlook:  
14 Stable) from Moody's.<sup>35</sup> PacifiCorp's current long-term issuer credit ratings are  
15 shown in Figure 6:

16 **Figure 6: PacifiCorp Credit Ratings<sup>36</sup>**

<b>Credit Rating Agency</b>	<b>Rating</b>	<b>Outlook</b>
Standard & Poor's	A	Stable
Moody's Investors Service	A3	Stable

<sup>31</sup> Berkshire Hathaway Energy Co., 2020 Form 10-K at 3.

<sup>32</sup> Company provided data.

<sup>33</sup> Company provided data.

<sup>34</sup> Berkshire Hathaway Energy Co., 2020 Form 10-K at 3.

<sup>35</sup> S&P Capital IQ accessed Jan. 18, 2022, and MOODY'S INVESTOR SERVICE, *Credit Opinion*, PacifiCorp (June 25, 2020).

<sup>36</sup> S&P GLOBAL RATINGS, RATINGS DIRECT, PacifiCorp (April 5, 2021) at 5, MOODY'S INVESTORS SERVICE, *Credit Opinion*, PacifiCorp (June 25, 2020).

1 **Q. How did you select the companies in your proxy group?**

2 A. I began with the group of 36 companies that Value Line classifies as Electric Utilities  
3 and applied the following screening criteria to select companies that:

- 4 • pay consistent quarterly cash dividends, because companies that do not cannot  
5 be analyzed using the Constant Growth DCF model;
- 6 • have investment grade long-term issuer ratings from S&P and/or Moody's;
- 7 • are covered by at least two utility industry analysts;
- 8 • have positive long-term earnings growth forecasts from at least two utility  
9 industry equity analysts;
- 10 • own regulated generation assets that are in ratebase;
- 11 • have more than five percent of owned regulated generation capacity from  
12 regulated coal-fired power plants;
- 13 • derive more than 60.00 percent of their total operating income from regulated  
14 operations;
- 15 • derive more than 60.00 percent of regulated operating income from gas  
16 distribution operations; and;
- 17 • were not parties to a merger or transformative transaction during the analytical  
18 periods relied on.

19 **Q. Did you exclude any other companies from the proxy group?**

20 A. Yes. Similar to the reason that I exclude transformative transactions; because the  
21 stock price can be affected by one-time events, I also excluded Pinnacle West Capital  
22 Corporation from the proxy group. The stock price of Pinnacle West Capital  
23 Corporation decreased approximately 24 percent over a two-month period from

1 October through November 2021 resulting from a negative regulatory decision for its  
2 largest operating company, Arizona Public Service Company. Therefore, I have  
3 excluded this company from the proxy group.

4 **Q. What is the composition of your proxy group?**

5 A. The screening criteria just discussed results in a proxy group consisting of the  
6 companies shown in Figure 7 (and also in Exhibit PAC/303).

7 **Figure 7: Proxy Group**

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
Otter Tail Corporation	OTTR
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy Inc.	XEL

8 **VII. COST OF EQUITY ESTIMATION**

9 **Q. Please briefly discuss the ROE in the context of a regulated utility.**

10 A. The regulatory construct requires that the regulatory agency, acting as a substitute for  
11 the competitive market, establish a ROR for the company that is commensurate with  
12 the ROR expected in the market for investments of similar risk. There can be  
13 adjustments to the ROE to reflect specific performance (e.g., positive adjustments  
14 recognizing strong management performance, cost savings and other important

1 operational metrics, or negative adjustments reflecting poor performance in similar  
2 metrics). Absent any adjustments for these types of performance measures, the base  
3 ROE is intended to reflect the return that investors require in order to invest in utility  
4 assets rather than investing in enterprises of comparable risk in the industry or  
5 competitive market.

6 The overall ROR for a regulated utility includes both the cost of debt and the cost  
7 of equity and is based on its weighted average cost of capital, whereby the costs of  
8 the individual sources of capital are weighted by their proportion in the capital  
9 structure. While the cost of debt and preferred stock can be directly observed, the  
10 cost of equity is market-based and, therefore, must be estimated based on observable  
11 market data.

12 **Q. How is the required ROE determined?**

13 A. The required ROE is estimated by using multiple analytical techniques that rely on  
14 market data to quantify investors' return requirements, adjusted for certain  
15 incremental costs and risks. Quantitative models produce a range of reasonable  
16 results from which the market-required ROE is selected. That selection must be  
17 based on a comprehensive review of relevant data and information, but it does not  
18 necessarily lend itself to a strict mathematical solution. The key consideration in  
19 determining the cost of equity is to ensure that the methodologies employed  
20 reasonably reflect investors' views of the financial markets in general and of the  
21 subject company (in the context of the proxy group) in particular.

22 **Q. What methods did you use to estimate PacifiCorp's cost of equity?**

23 A. I considered the results of the Constant Growth DCF model, the Multi-Stage DCF

1 model, the CAPM, and the Bond Yield Plus Risk Premium approach. As discussed in  
2 more detail below, a reasonable ROE estimate considers alternative methodologies,  
3 observable market data, and the reasonableness of their individual and collective  
4 results.

5 **A. Importance of Multiple Analytical Approaches**

6 **Q. Why is it important to use more than one analytical approach?**

7 A. Because the cost of equity is not directly observable, it must be estimated based on  
8 both quantitative and qualitative information. When faced with the task of estimating  
9 the cost of equity, analysts and investors are inclined to gather and evaluate as much  
10 relevant data as reasonably can be analyzed. Several models have been developed to  
11 estimate the cost of equity, and I use multiple approaches to estimate the cost of  
12 equity. As a practical matter, however, all of the models available for estimating the  
13 cost of equity are subject to limiting assumptions or other methodological  
14 constraints. Consequently, many well-regarded finance texts recommend using  
15 multiple approaches when estimating the cost of equity. For example, Copeland,  
16 Koller, and Murrin<sup>37</sup> suggest using the CAPM and Arbitrage Pricing Theory model,  
17 while Brigham and Gapenski<sup>38</sup> recommend the CAPM, DCF, and Bond Yield Plus  
18 Risk Premium approaches. Consistent with the *Hope* finding, it is the analytical  
19 result, not the methodology employed, which is controlling in arriving at ROE  
20 determinations.

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<sup>37</sup> TOM COPELAND, TIM KOLLER AND JACK MURRIN, VALUATION: MEASURING AND MANAGING THE VALUE OF COMPANIES, AT 214 (3rd Ed 2000).

<sup>38</sup> EUGENE BRIGHAM, LOUIS GAPENSKI, FINANCIAL MANAGEMENT: THEORY AND PRACTICE at 341 (7th ed. 1994).



1 **Q. Is it important given the current market conditions to use more than one**  
2 **analytical approach?**

3 A. Yes. Low interest rates and the effects of the investor “flight to quality” associated  
4 with the pandemic can be seen in relatively high utility share valuations compared to  
5 historical levels and to the broader market. Higher utility stock valuations produce  
6 lower dividend yields and result in lower cost of equity estimates from a DCF  
7 analysis. Lower interest rates also affect the CAPM in two ways: (1) the risk-free rate  
8 is lower than it is expected to be going forward; and (2) because the market risk  
9 premium is a function of interest rates (*i.e.*, it is the return on the broad stock market  
10 less the risk-free interest rate), the market risk premium is expected to be higher when  
11 interest rates are lower. Therefore, it is important to use multiple analytical  
12 approaches to moderate the effect of the current low interest rate environment on the  
13 ROE estimates for the proxy group, and where possible, consider using projected  
14 market data in the models to estimate the return for the forward-looking period.

15 **Q. Has the Commission recognized that it is important to consider the results of**  
16 **multiple ROE estimation models?**

17 A. Yes. In previous cases, the Commission has considered the results of many ROE  
18 estimation models and determined, based on the results of those models, whether or  
19 not to place any weight on the model in its final determination. Specifically, in the  
20 Company’s last case, the Commission considered the results of the DCF, CAPM and  
21 Risk Premium approaches:

22           The Commission has previously accepted CAPM as a “useful and  
23           reliable addition to the DCF results” for determining cost of equity  
24           in certain cases. While we have historically rejected the risk  
25           premium analysis as unconventional and because it had not been

1                   accepted by other regulatory agencies, we note that FERC now gives  
2                   equal consideration to DCF, CAPM and risk premium results.<sup>39</sup>

3                   Further, the Commission recognized that no one party's application of any model is  
4                   correct or certain. In that proceeding, the Commission considered the range of results  
5                   established using the DCF model, the CAPM and the risk premium models. Further,  
6                   the Commission recognized that the effects of the pandemic caused additional  
7                   uncertainty in the assumptions used in the models. In addition, the Commission  
8                   recognized incremental risk associated with the Company's capital investment plan  
9                   and further recognized the relationship between the ROE and equity ratio.<sup>40</sup>

10                  **B.       Constant Growth DCF Model**

11                  **Q.       Please describe the DCF approach.**

12                  A.       The DCF approach is based on the theory that a stock's current price represents the  
13                  present value of all expected future cash flows. In its most general form, the DCF  
14                  model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \dots + \frac{D_\infty}{(1+k)^\infty}$$

16                  Where  $P_0$  represents the current stock price,  $D_1 \dots D_\infty$  are all expected future  
17                  dividends, and  $k$  is the discount rate, or required ROE. Equation [1] is a standard  
18                  present value calculation that can be simplified and rearranged into the following  
19                  form:

$$k = \frac{D_0(1+g)}{P_0} + g$$

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<sup>39</sup> Order No. 20-476 at 30.

<sup>40</sup> *Id.*, at 30-31.

1                   Equation [2] is often referred to as the Constant Growth DCF model in which  
2                   the first term is the expected dividend yield and the second term is the expected long-  
3                   term growth rate.

4   **Q.    What assumptions are required for the Constant Growth DCF model?**

5   A.    The Constant Growth DCF model requires the following assumptions: (1) a constant  
6           growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a  
7           constant price-to-earnings (P/E) ratio; and (4) a discount rate greater than the  
8           expected growth rate. To the extent any of these assumptions is violated, considered  
9           judgment and/or specific adjustments should be applied to the results.

10 **Q.    What market data did you use to calculate the dividend yield in your Constant**  
11 **Growth DCF model?**

12 A.    The dividend yield in my Constant Growth DCF model is based on the proxy group  
13           companies' current annual dividend and average closing stock prices over the 30-,  
14           90-, and 180-trading days ended December 31, 2021.

15 **Q.    Did you make any adjustments to the dividend yield to account for periodic**  
16 **growth in dividends?**

17 A.    Yes. Since utility companies tend to increase their quarterly dividends at different  
18           times throughout the year, it is reasonable to assume that dividend increases will be  
19           evenly distributed over calendar quarters. Given that assumption, it is reasonable to  
20           apply one-half of the expected annual dividend growth rate for purposes of  
21           calculating the expected dividend yield component of the DCF model. This  
22           adjustment ensures that the expected first year dividend yield is, on average,

1 representative of the coming 12-month period, and does not overstate the aggregated  
2 dividends to be paid during that time.

3 **Q. Why is it important to select appropriate measures of long-term growth in**  
4 **applying the DCF model?**

5 A. In its Constant Growth form, the DCF model (*i.e.*, Equation [2]) assumes a single  
6 long-term growth rate in perpetuity. In order to reduce the long-term growth rate to a  
7 single measure, one must assume that the dividend payout ratio remains constant and  
8 that Earnings Per Share (EPS), dividends per share, and book value per share all grow  
9 at the same constant rate. Over the long run, however, dividend growth can only be  
10 sustained by earnings growth. Therefore, it is important to incorporate a variety of  
11 sources of long-term earnings growth rates into the Constant Growth DCF model.

12 **Q. What sources of long-term growth rates did you rely on in your Constant**  
13 **Growth DCF model?**

14 A. As shown in Exhibit PAC/304, my Constant Growth DCF model incorporates three  
15 sources of long-term growth rates: (1) consensus long-term earnings growth estimates  
16 from Zacks Investment Research; (2) consensus long-term earnings growth estimates  
17 from Thomson First Call (provided by Yahoo! Finance); and (3) long-term earnings  
18 growth estimates from Value Line Investment Survey (Value Line).

19 **Q. How did you calculate the range of results for the Constant Growth DCF model?**

20 A. I calculated the low-end result for the Constant Growth DCF model using the lowest  
21 projected earnings growth rate (*i.e.*, the lowest of First Call, Zacks, and Value Line)  
22 for each of the proxy group companies. I applied a similar approach to calculate the  
23 high-end result for the Constant Growth DCF model by using the highest projected

1 earnings growth rate of the three sources for each proxy group company. The median  
2 results of the Constant Growth DCF model were calculated using the mean growth  
3 rate of the three sources for each proxy group company as well as the low and high  
4 growth rate scenarios. Once the results for each proxy group company were  
5 calculated, I then relied on the median of the results as the measure of central  
6 tendency for purposes of my analysis, referring to each of the results as the “median  
7 low,” “median” and “median high” results.

8 **C. Multi-Stage DCF Model**

9 **Q. What other forms of the DCF model have you considered?**

10 A. Consistent with Commission precedent, I also considered the results of a Multi-Stage  
11 form of the DCF model. As with the Constant Growth DCF model, the Multi-Stage  
12 form defines the cost of equity as the discount rate that sets the current price equal to  
13 the discounted value of future cash flows.

14 **Q. Has the Commission expressed a preference for the results of the Multi-Stage  
15 DCF model?**

16 A. Yes, the Commission has indicated that it prefers the results of the Multi-Stage DCF  
17 model. For example, in its recent order in PacifiCorp’s last proceeding, the  
18 Commission stated:

19 This Commission has primarily relied upon the multi-stage DCF  
20 model in determining a reasonable range of ROE, and in this case  
21 we are not persuaded to depart from that approach. In this case, we  
22 will also consider the results of the CAPM and risk-premium models  
23 presented by the parties to confirm the reasonableness of that range  
24 and of the ROE authorized in this case.<sup>41</sup>

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<sup>41</sup> Order No. 20-476 at 30.

1           While I agree that the Multi-Stage DCF model is one of the methods among  
2 investors and regulators, I also agree with the Commission that it is reasonable to  
3 consider the results of other models to confirm the reasonableness of the results of  
4 that model. In the current market environment, it is the high valuations and low  
5 dividend yields for utility stocks that are causing the DCF model to produce  
6 unreliable results, not the earnings growth rates for utility companies, which have  
7 generally remained within the traditional range of five to seven percent. Under more  
8 normal market conditions, the single-stage form of the DCF model generally  
9 produces reasonable and reliable estimates of the cost of equity for companies in  
10 stable, mature industries, such as regulated utilities.

11 **Q. How does the Multi-Stage form of the DCF model differ from the Constant**  
12 **Growth form of the DCF model?**

13 A. The Multi-Stage DCF model, which is an extension of the Constant Growth form,  
14 enables the analyst to specify different growth rates over multiple stages. The Multi-  
15 Stage DCF model allows for a gradual transition from the first-stage growth rate to  
16 the long-term growth rate, thereby avoiding the unrealistic assumption that growth  
17 changes abruptly between the first and final stages.

18 **Q. Please generally describe the structure of your Multi-Stage DCF model.**

19 A. The Multi-Stage DCF model sets a company's current stock price equal to the present  
20 value of future cash flows received over three "stages." In all three stages, cash flows  
21 are equal to the annual dividend payments that stockholders receive. Stage One is a  
22 short-term growth period that consists of the first five years; Stage Two is a transition  
23 period from the short-term growth rate to the long-term growth rate (i.e., years six

1 through 10); and Stage Three is a long-term growth period that begins in year 11 and  
2 continues in perpetuity (i.e., year 200). The ROE is then calculated as the ROR that  
3 results from the initial stock investment and the dividend payments over the analytical  
4 period.

5 **Q. Please summarize the EPS growth rates used in your Multi-Stage DCF model.**

6 A. As shown in Exhibit PAC/305, I began with the current annualized dividend as of  
7 December 31, 2021 for each proxy group company. In the first stage of the model,  
8 the current annualized dividend is escalated based on the average of the three- to five-  
9 year earnings growth estimates reported by Zacks, Thomson First Call, and Value  
10 Line. For the third stage, I relied on long-term projected growth in GDP. The second  
11 stage growth rate is a transition from the first stage growth rate to the long-term  
12 growth rate on a geometric average basis.

13 **Q. How did you calculate the long-term GDP growth rate?**

14 A. As shown in Exhibit PAC 306, the long-term growth rate of 5.49 percent is based on  
15 real GDP growth rate of 3.13 percent from 1929 through 2020,<sup>42</sup> and a projected  
16 inflation rate of 2.28 percent. The projected inflation rate is based on three measures:  
17 (1) the average long-term projected growth rate in the CPI of 2.20 percent;<sup>43</sup> (2) the  
18 compound annual growth rate of the CPI for all urban consumers for 2031-2050 of  
19 2.27 percent as projected by the Energy Information Administration (EIA); and (3)  
20 the compound annual growth rate of the GDP chain-type price index for 2031-2050  
21 of 2.37 percent, also reported by the EIA.<sup>44</sup>

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<sup>42</sup> U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts Tables, Table 1.1.1, December 31, 2021.

<sup>43</sup> Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14.

<sup>44</sup> U.S. Energy Information Administration, Annual Energy Outlook 2021, Table 20, Macroeconomic Indicators.

1 **Q. Do the assumptions used in the Multi-Stage DCF model address the effect of low**  
2 **dividend yields on the DCF results?**

3 A. No, they do not. While the Multi-Stage DCF model provides for changes in growth  
4 over time, it does not address the abnormally low dividend yields for utility stocks  
5 and the effect of those low dividend yields on the DCF model, specifically the  
6 understated ROEs that result from the use of these assumptions. For that reason, I  
7 have also considered the results of risk-premium based methodologies, which I will  
8 discuss later in my direct testimony.

9 **D. Discounted Cash Flow Model Results**

10 **Q. How did you calculate the range of results for the Constant Growth and Multi-**  
11 **Stage DCF models?**

12 A. I calculated the low result for both DCF models using the minimum growth rate (*i.e.*,  
13 the lowest of the First Call, Zacks, and Value Line earnings growth rates) for each of  
14 the proxy group companies. Thus, the low result reflects the minimum DCF result for  
15 the proxy group. I used a similar approach to calculate the high results, using the  
16 highest growth rate for each proxy group company. The mean results were calculated  
17 using the average growth rates from all sources.

18 **Q. What are the results of your DCF analyses?**

19 A. Figure 8 summarizes the results of my DCF analyses. As shown in Figure 8, the  
20 median Constant Growth DCF results range from 9.35 percent to 9.50 percent and the  
21 median high results range from 10.28 percent to 10.37 percent. The median Multi-



1 Stage DCF results range from 9.45 percent to 9.50 percent and the median high  
2 results are in the range of 9.73 percent to 9.81 percent.

3 **Figure 8: Discounted Cash Flow Results**

	Mean Low	Mean	Mean High
<b>Median Constant Growth DCF<sup>45</sup></b>			
30-Day Average	8.57%	9.44%	10.34%
90-Day Average	8.62%	9.50%	10.37%
180-Day Average	8.63%	9.35%	10.28%
<b>Median Multi-Stage DCF<sup>46</sup></b>			
30-Day Average	9.01%	9.45%	9.79%
90-Day Average	9.03%	9.50%	9.81%
180-Day Average	9.02%	9.48%	9.73%

4 **Q. What are your conclusions about the results of the DCF models?**

5 A. As discussed previously, one primary assumption of the DCF models is a constant  
6 P/E ratio. That assumption is heavily influenced by the market price of utility stocks.  
7 Since utility stocks are expected to underperform the broader market over the near-  
8 term as interest rates increases, it is important to consider the results of the DCF  
9 models with caution. This means that the results of the DCF models, which rely on  
10 historical stock prices, are below where they would be expected to be going forward  
11 during the period in which the rates for the Company will be in effect. Therefore,  
12 while I have given weight to the results of the DCF models, my recommendation also  
13 gives weight to the results of other ROE estimation models.

14 **E. CAPM Analysis**

15 **Q. Please briefly describe the Capital Asset Pricing Model.**

16 A. The CAPM is a risk premium approach that estimates the cost of equity for a given

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<sup>45</sup> See Exhibit PAC/304.

<sup>46</sup> See Exhibit PAC/305.

1 security as a function of a risk-free return plus a risk premium to compensate  
2 investors for the non-diversifiable or “systematic” risk of that security.<sup>47</sup> This second  
3 component is the product of the market risk premium and the Beta coefficient, which  
4 measures the relative riskiness of the security being evaluated.

5 The CAPM is defined by four components, each of which must theoretically  
6 be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f)$$

8 Where:

9  $K_e$  = the required market ROE;

10  $\beta$  = Beta coefficient of an individual security;

11  $r_f$  = the risk-free ROR; and

12  $r_m$  = the required return on the market as a whole.

13 In this specification, the term ( $r_m - r_f$ ) represents the Market Risk Premium.

14 According to the theory underlying the CAPM, since unsystematic risk can be  
15 diversified away, investors should only be concerned with systematic risk.

16 Systematic risk is measured by Beta, which is a measure of the volatility of a security  
17 as compared to the overall market. Beta is defined as:

$$\beta = \frac{\text{Covariance}(r_e, r_m)}{\text{Variance}(r_m)} \quad [4]$$

18 The variance of the market return (i.e., Variance ( $r_m$ )) is a measure of the uncertainty  
19 of the general market. The covariance between the return on a specific security and

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<sup>47</sup> Systematic risk is the risk inherent in the entire market or market segment. This form of risk cannot be diversified away using a portfolio of assets. Non-systematic risk is the risk of a specific company that can be mitigated through portfolio optimization.

1 the general market (*i.e.*, Covariance ( $r_e$ ,  $r_m$ )) reflects the extent to which the return on  
2 that security will respond to a given change in the general market return. Thus, Beta  
3 represents the risk of the security relative to the general market.

4 **Q. What risk-free rate did you use in your CAPM analysis?**

5 A. I relied on three sources for my estimate of the risk-free rate: (1) the current 30-day  
6 average yield on 30-year Treasury bonds of 1.87 percent;<sup>48</sup> (2) the projected 30-year  
7 Treasury yield for Q2 2022–Q2 2023 of 2.52 percent;<sup>49</sup> and (3) the average projected  
8 30-year Treasury bond yield for the period 2022 through 2026 of 3.40 percent.<sup>50</sup>

9 **Q. Would you place more weight on one of these scenarios?**

10 A. Yes. Based on current market conditions, I place more weight on the results of the  
11 projected yields on the 30-year Treasury bonds. As discussed previously, the  
12 estimation of the cost of equity in this case should be forward-looking because it is  
13 the return that investors would receive over the future rate period. Therefore, the  
14 inputs and assumptions used in the CAPM analysis should reflect the expectations of  
15 the market at that time. While I have included the results of a CAPM analysis that  
16 relies on a current 30-day average risk-free rate, this analysis fails to take into  
17 consideration the effect of the market's expectations for interest rate increases on the  
18 cost of equity.

19 **Q. What Beta coefficients did you use in your CAPM analysis?**

20 A. As shown in Exhibit PAC/307, I used the Beta coefficients for the proxy group  
21 companies as reported by Bloomberg and Value Line. The Beta coefficients reported

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<sup>48</sup> Bloomberg Professional as of December 31, 2021.

<sup>49</sup> Blue Chip Financial Forecasts, Vol. 41, No. 1, January 1, 2022, at 2.

<sup>50</sup> Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14.

1 by Bloomberg are calculated using 10 years of weekly returns relative to the S&P 500  
2 Index. The Beta coefficients reported by Value Line are calculated based on five  
3 years of weekly returns relative to the New York Stock Exchange Composite Index.  
4 Additionally, as shown in Exhibit PAC/307, I also considered an additional CAPM  
5 analysis that relies on the long-term average Beta coefficient reported by Value Line  
6 for the companies in my proxy group from 2011 through 2021.

7 **Q. How did you estimate the Market Risk Premium in the CAPM?**

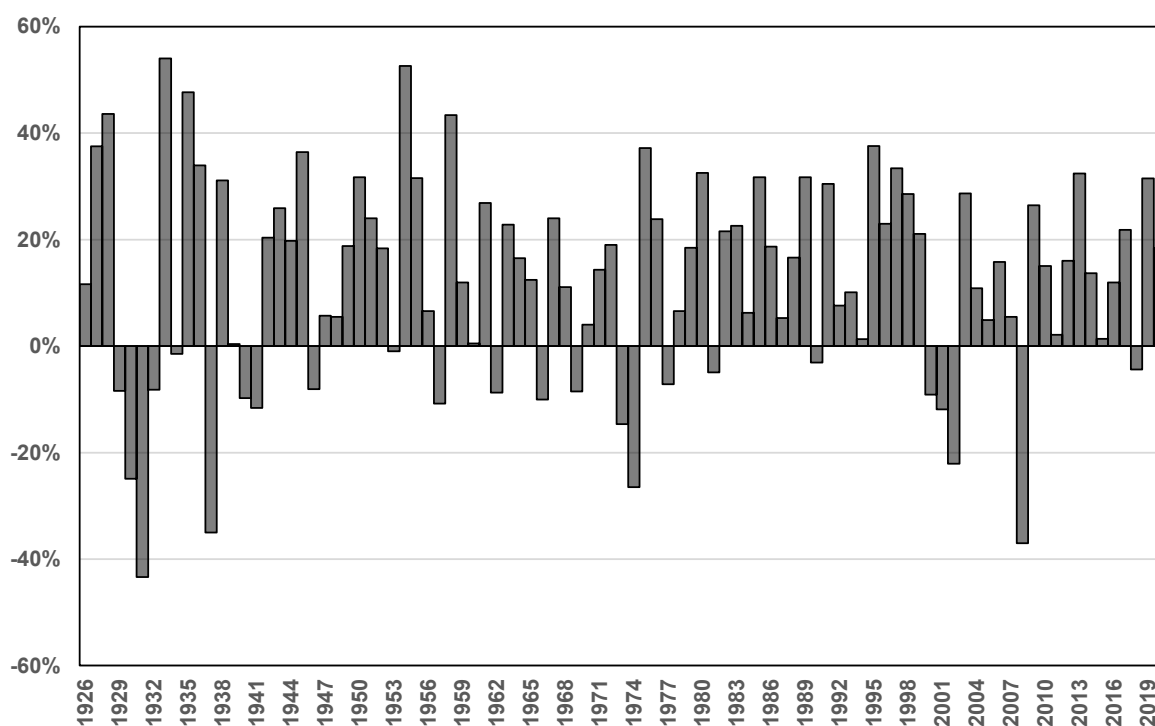
8 A. I estimated the market risk premium as the difference between the implied expected  
9 equity market return and the risk-free rate. The expected return on the S&P 500  
10 Index is calculated using the Constant Growth DCF model discussed earlier in my  
11 testimony for the companies in the S&P 500 Index for which dividend yields and  
12 Value Line long-term earnings projections are available. In addition, I exclude those  
13 companies whose earnings projections are either greater than 20.00 percent or lower  
14 than 0.00 percent. As shown in Exhibit PAC/307, based on an estimated market  
15 capitalization-weighted dividend yield of 1.48 percent and a weighted long-term  
16 growth rate of 11.06 percent, the estimated required market return for the S&P 500  
17 Index is 12.63 percent. The implied market risk premium over the risk-free rates  
18 evaluated (*i.e.*, the current, near-term projected and longer-term projected 30-year  
19 U.S. Treasury bond yield) ranges from 9.23 percent to 10.76 percent.

20 **Q. How does the expected market return you have calculated compare to observed**  
21 **historical market returns?**

22 A. Given the range of annual equity returns that have been observed over the past  
23 century as shown in Figure 9, a current expected market return of 12.63 percent is

1 consistent with the historical returns. In fact, in 49 out of the past 95 years (or  
2 approximately 52 percent of the observations), the realized equity return was at least  
3 12.63 percent or greater.

4 **Figure 9: Realized U.S. equity market returns (1926–2020)<sup>51</sup>**



5 **Q. What are the results of your CAPM analyses?**

6 A. As shown in Figure 10, my traditional CAPM analysis produces a range of returns  
7 from 9.72 percent to 11.47 percent.

<sup>51</sup> Depicts total annual returns on large company stocks, as reported in the 2021 Duff & Phelps SBBI Yearbook.

1

**Figure 10: CAPM Results**

	<b>Current Risk-Free Rate (1.87%)</b>	<b>Q2 2022 – Q2 2023 Projected Risk-Free Rate (2.52%)</b>	<b>2023-2027 Projected Risk-Free Rate (3.40%)</b>
<b>CAPM</b>			
Value Line Beta	11.28%	11.36%	11.47%
Bloomberg Beta	10.56%	10.68%	10.85%
Long-term Avg. Beta	9.72%	9.90%	10.14%

2

**F. Bond Yield Plus Risk Premium Analysis**

3 **Q.**

**Please describe the Bond Yield Plus Risk Premium approach.**

4 **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 a bondholder. That is, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Risk premium approaches, therefore, 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 used actual authorized returns for natural gas utility companies as the historical measure of the cost of equity to determine the risk premium.

13 **Q.**

**Are there other considerations that should be addressed in conducting this analysis?**

15 **A.**

Yes. 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. That is, as interest rates increase (decrease), the equity risk premium decreases (increases). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity

19

1 risk premium; and (2) relies on recent and expected market conditions. Such an  
2 analysis can be developed based on a regression of the risk premium as a function of  
3 U.S. Treasury bond yields. If authorized ROEs for natural gas utilities serve as the  
4 measure of required equity returns and define the yield on the long-term U.S.  
5 Treasury bond as the relevant measure of interest rates, the risk premium simply  
6 would be the difference between those two points.<sup>52</sup>

7 **Q. Is the Bond Yield Plus Risk Premium analysis relevant to investors?**

8 A. Yes. Investors are aware of ROE awards in other jurisdictions, and they consider  
9 those awards as a benchmark for a reasonable level of equity returns for utilities of  
10 comparable risk operating in other jurisdictions. Because my Bond Yield Plus Risk  
11 Premium analysis is based on authorized ROEs for utility companies relative to  
12 corresponding Treasury yields, it provides relevant information to assess the return  
13 expectations of investors.

14 **Q. What did your Bond Yield Plus Risk Premium analysis reveal?**

15 A. As shown in Figure 11, from 1992 through December 2021, there was a strong  
16 negative relationship between risk premia and interest rates. To estimate that  
17 relationship, I conducted a regression analysis using the following equation:

18 
$$RP = a + b(T) \text{ [6]}$$

19 Where:

20 RP = Risk Premium (difference between authorized ROEs and the yield on 30-

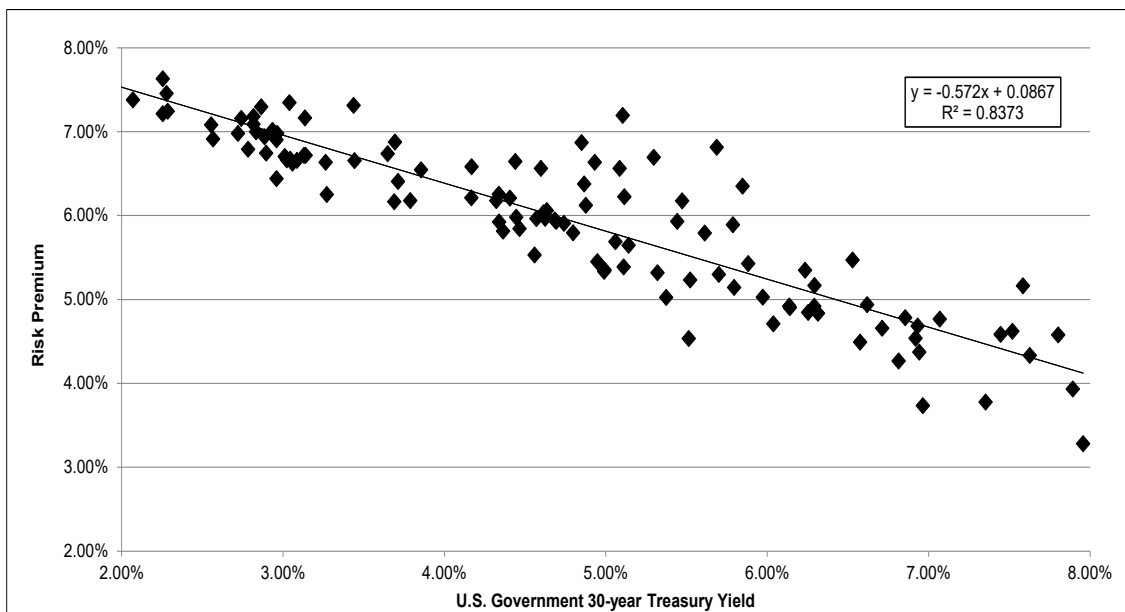
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<sup>52</sup> See e.g., S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, MANAGERIAL AND DECISION ECONOMICS, Vol. 19, No. 2 (March 1998) (in which the author used a methodology similar to the regression approach described below, including using allowed 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 Shareholders Required Rates of Return*, FINANCIAL MANAGEMENT, Spring 1986 at 66.

1 year U.S. Treasury bonds)  
2  $a$  = intercept term  
3  $b$  = slope term  
4  $T$  = 30-year U.S. Treasury bond yield

5 Data regarding allowed ROEs were derived from more than 666 vertically integrated  
6 electric utility rate cases from 1992 through December 2021 as reported by  
7 Regulatory Research Associates (RRA). The equation's coefficients were statistically  
8 significant at the 99.00 percent level.

9 **Figure 11: Risk Premium Results**



10 As shown on Exhibit PAC/308, based on the current 30-day average of the 30-year  
11 U.S. Treasury bond yield (*i.e.*, 1.87 percent), the risk premium would be 7.61 percent,  
12 resulting in an estimated ROE of 9.47 percent. Based on the near-term (Q2 2022–Q2  
13 2023) projected 30-year U.S. Treasury bond yield (*i.e.*, 2.52 percent), the risk  
14 premium would be 7.23 percent, resulting in an estimated ROE of 9.75 percent.



1 Based on longer-term (2023–2027) projected 30-year U.S. Treasury bond yield (*i.e.*,  
2 3.40 percent), the risk premium would be 6.73 percent, resulting in an estimated ROE  
3 of 10.13 percent.

4 **Q. How do the results of the Bond Yield Risk Premium analysis inform your**  
5 **recommended ROE for PacifiCorp?**

6 A. In conjunction with the other ROE models that I have discussed, I have considered  
7 the results of the Bond Yield Risk Premium analysis in setting my recommended  
8 ROE for PacifiCorp. As noted above, investors consider the ROE award of a  
9 company when assessing the risk of that company as compared to utilities of  
10 comparable risk operating in other jurisdictions. The risk premium analysis accounts  
11 for this comparison by estimating the return expectations of investors based on the  
12 current and past ROE awards of natural gas utilities across the US.

13 **VIII. REGULATORY AND BUSINESS RISKS**

14 **Q. Do the median and mean results of the DCF, CAPM, and Risk Premium**  
15 **analyses for the proxy group provide an appropriate estimate of the cost of**  
16 **equity for PacifiCorp?**

17 A. No. These results provide only a range of the appropriate estimate of PacifiCorp's  
18 cost of equity. Several additional factors must be considered when determining  
19 where the Company's cost of equity falls within the range of analytical results. These  
20 risk factors, discussed below, should be considered with respect to their overall effect  
21 on PacifiCorp's risk profile relative to the proxy group.

1           **A.     Capital Expenditures**

2   **Q.     Please summarize PacifiCorp’s capital expenditure requirements.**

3   A.     PacifiCorp’s current projections for 2022 through 2026 include approximately  
4           \$12.04 billion in capital investments for the period.<sup>53</sup> Based on PacifiCorp’s net  
5           utility plant of approximately \$22.4 billion as of December 31, 2021, the ratio of  
6           projected capital expenditures to net utility plant is approximately 53.68 percent.

7   **Q.     How is PacifiCorp’s risk profile affected by its capital expenditure  
8           requirements?**

9   A.     As with any utility facing increased capital expenditure requirements, the Company’s  
10          risk profile may be adversely affected in two significant and related ways: (1) the  
11          heightened level of investment increases the risk of under recovery or delayed  
12          recovery of the invested capital; and (2) an inadequate return would put downward  
13          pressure on key credit metrics.

14   **Q.     Do credit rating agencies recognize the risks associated with elevated levels of  
15          capital expenditures?**

16   A.     Yes. From a credit perspective, the additional pressure on cash flows associated with  
17          higher levels of capital expenditures exerts corresponding pressure on credit metrics  
18          and, therefore, credit ratings. To that point, S&P explains the importance of  
19          regulatory support for large capital projects:

20                   When applicable, a jurisdiction’s willingness to support large  
21                   capital projects with cash during construction is an important aspect  
22                   of our analysis. This is especially true when the project represents  
23                   a major addition to rate base and entails long lead times and  
24                   technological risks that make it susceptible to construction delays.  
25                   Broad support for all capital spending is the most credit- sustaining.

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<sup>53</sup> Source: Company provided data.

1 Support for only specific types of capital spending, such as specific  
2 environmental projects or system integrity plans, is less so, but still  
3 favorable for creditors. Allowance of a cash return on construction  
4 work-in-progress or similar ratemaking methods historically were  
5 extraordinary measures for use in unusual circumstances, but when  
6 construction costs are rising, cash flow support could be crucial to  
7 maintain credit quality through the spending program. Even more  
8 favorable are those jurisdictions that present an opportunity for a  
9 higher return on capital projects as an incentive to investors.<sup>54</sup>

10 Therefore, to the extent that PacifiCorp's rates do not permit the opportunity to  
11 recover its full cost of doing business, the Company will face increased recovery risk  
12 and thus increased pressure on its credit metrics.

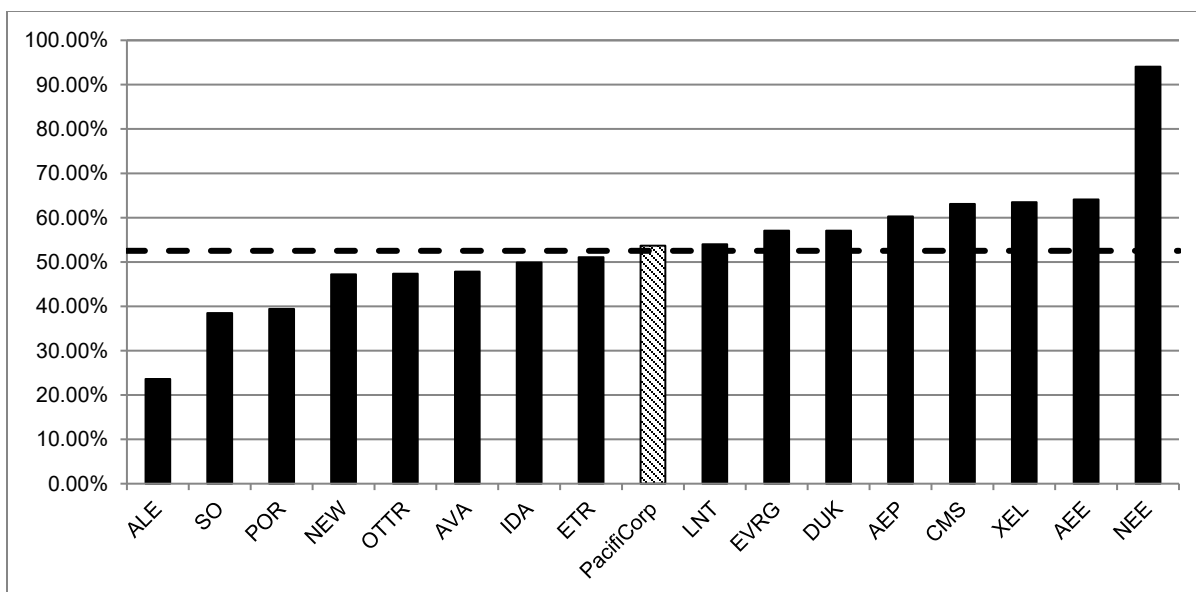
13 **Q. How do PacifiCorp's capital expenditure requirements compare to those of the**  
14 **proxy group companies?**

15 A. As shown in Exhibit PAC/309 CapEx 1, I calculated the ratio of expected capital  
16 expenditures to net utility plant for PacifiCorp and each of the companies in the proxy  
17 group by dividing each company's projected capital expenditures for the period from  
18 2022–2026 by its total net utility plant as of December 31, 2020. As shown in  
19 Exhibit PAC/309 CapEx 2 (see also Figure 12 below), PacifiCorp's ratio of capital  
20 expenditures as a percentage of net utility plant of 53.68 percent is similar to the  
21 median of the proxy group companies of 52.53 percent.

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<sup>54</sup> S&P GLOBAL RATINGS, Assessing U.S. Investor-Owned Utility Regulatory Environments at 7 (Aug. 10, 2016).

1 **Figure 12: Comparison of Capital Expenditures to Proxy Group Companies**



2 **Q. Does PacifiCorp have a capital tracking mechanism to recover the costs**  
 3 **associated with capital expenditures between rate cases?**

4 A. Yes. PacifiCorp is authorized to recover costs associated with costs to construct or  
 5 acquire renewable generation facilities and the associated transmission.

6 As shown in Exhibit PAC/310, 52.38 percent of the proxy group utilities  
 7 recover costs through capital tracking mechanisms.

8 **Q. What are your conclusions regarding the effect of the Company's capital**  
 9 **spending requirements on its risk profile and cost of capital?**

10 A. PacifiCorp's capital expenditure requirements as a percentage of net utility plant are  
 11 significant over the next few years and these investments create additional risk for the  
 12 Company, as noted by the Commission in the Company's last rate proceeding.

1       **B.       Regulatory Risks**

2       **Q.       Please explain how the regulatory environment affects investors' risk**  
3       **assessments.**

4       A.       The ratemaking process is premised on the principle that, for investors and companies  
5       to commit the capital needed to provide safe and reliable utility service, the subject  
6       utility must have the opportunity to recover the return of, and the market-required  
7       return on, invested capital. Regulatory authorities recognize that because utility  
8       operations are capital intensive, regulatory decisions should enable the utility to  
9       attract capital at reasonable terms, and that doing so balances the long-term interests  
10      of investors and customers. Utilities must finance their operations and thus require  
11      the opportunity to earn a reasonable return on their invested capital to maintain their  
12      financial profiles. PacifiCorp is no exception, and in that respect, the regulatory  
13      environment is one of the most important factors considered in both debt and equity  
14      investors' risk assessments.

15             From the perspective of debt investors, the authorized return should enable the  
16      utility to generate the cash flow needed to meet its near-term financial obligations,  
17      make the capital investments needed to maintain and expand its systems, and  
18      maintain the necessary levels of liquidity to fund unexpected events. This financial  
19      liquidity must be derived not only from internally generated funds, but also by  
20      efficient access to capital markets. Moreover, because fixed income investors have  
21      many investment alternatives, even within a given market sector, a utility's financial  
22      profile must be adequate on a relative basis to ensure its ability to attract capital under  
23      a variety of economic and financial market conditions.

1 Equity investors require that the authorized return be adequate to provide a  
2 risk-comparable return on the equity portion of the utility's capital investments.

3 Because equity investors are the residual claimants on the utility's cash flows (*i.e.*, the  
4 equity return is subordinate to interest payments), they are particularly concerned  
5 with the strength of regulatory support and its effect on future cash flows.

6 **Q. Please explain how credit rating agencies consider regulatory risk in establishing**  
7 **a company's credit rating.**

8 A. Both S&P and Moody's consider the overall regulatory framework in establishing  
9 credit ratings. Moody's establishes credit ratings based on four key factors: (1)  
10 regulatory framework; (2) the ability to recover costs and earn returns; (3)  
11 diversification; and (4) financial strength, liquidity and key financial metrics. Of  
12 these criteria, regulatory framework and the ability to recover costs and earn returns  
13 are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns  
14 regulatory risk a 50.00 percent weighting in the overall assessment of business and  
15 financial risk for regulated utilities.<sup>55</sup>

16 S&P also identifies the regulatory framework as an important factor in credit  
17 ratings for regulated utilities, stating: "One significant aspect of regulatory risk that  
18 influences credit quality is the regulatory environment in the jurisdictions in which a  
19 utility operates."<sup>56</sup> S&P identifies four specific factors that it uses to assess the credit  
20 implications of the regulatory jurisdictions of investor-owned regulated utilities: (1)

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<sup>55</sup> MOODY'S INVESTORS SERVICE, Rating Methodology: Regulated Electric and Gas Utilities at 4 (June 23, 2017).

<sup>56</sup> S&P GLOBAL RATINGS, Ratings Direct, U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality—But Some More So Than Others at 2 (June 25, 2018).

1 regulatory stability; (2) tariff-setting procedures and design; (3) financial stability;  
2 and (4) regulatory independence and insulation.<sup>57</sup>

3 **Q. How does the regulatory environment in which a utility operates affect its access**  
4 **to and cost of capital?**

5 A. The regulatory environment can significantly affect both the access to and cost of  
6 capital in several ways. First, the proportion and cost of debt capital available to  
7 utility companies are influenced by the rating agencies' assessment of the regulatory  
8 environment. As noted by Moody's, "[f]or rate regulated utilities, which typically  
9 operate as a monopoly, the regulatory environment and how the utility adapts to that  
10 environment are the most important credit considerations."<sup>58</sup> Moody's further  
11 highlighted the relevance of a stable and predictable regulatory environment to a  
12 utility's credit quality, noting:

13 [b]roadly speaking, the Regulatory Framework is the foundation for  
14 how all the decisions that affect utilities are made (including the  
15 setting of rates), as well as the predictability and consistency of  
16 decision-making provided by that foundation."<sup>59</sup>

17 **Q. Have you conducted an analysis of the regulatory framework in Oregon for**  
18 **PacifiCorp's business relative to the jurisdictions in which the companies in your**  
19 **proxy group operate?**

20 A. Yes. I have evaluated the regulatory framework in Oregon based on five factors that  
21 are important in terms of providing a regulated utility an opportunity to earn its  
22 authorized ROE. These factors are: (1) fuel cost recovery; (2) the test year

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<sup>57</sup> *Id.*, at 1.

<sup>58</sup> MOODY'S INVESTOR SERVICES, Rating Methodology: Regulated Electric and Gas Utilities at 6 (Jun. 23, 2017).

<sup>59</sup> *Id.*

1 convention for ratemaking (*i.e.*, forecast vs. historical test year); (3) method for  
2 determining rate base for ratemaking (*i.e.*, average vs. year-end rate base); (4) use of  
3 revenue decoupling or other clauses that mitigate volumetric risk; and (5) prevalence  
4 of capital cost recovery between rate cases. The results of my regulatory risk  
5 assessment are shown in Exhibit PAC/310 and are summarized below.

6 1. Fuel Cost Recovery: PacifiCorp has a Power Cost Adjustment Mechanism  
7 (PCAM) to recover power costs. However, while traditional fuel cost  
8 recovery mechanisms allow all variances between projected fuel costs and  
9 actual fuel costs to be recovered from or refunded to customers, the PCAM for  
10 PacifiCorp has a deadband that requires PacifiCorp to absorb some portion of  
11 the variation in power costs. If the power cost variation falls within this  
12 deadband, there will be no power cost rate adjustment. The PCAM has an  
13 asymmetrical deadband, which requires that PacifiCorp absorb variances  
14 between negative \$15 million and positive \$30 million. The PCAM also has a  
15 sharing mechanism, whereby any power cost variance outside the deadband  
16 will be shared 90 percent by customers and 10 percent by PacifiCorp if  
17 PacifiCorp earns within plus or minus 100 basis points of its authorized  
18 ROE.<sup>60</sup> If PacifiCorp is earning within this range of its authorized ROE, there  
19 will be no power cost adjustment for that year. Finally, amortization of  
20 deferred amounts in any one year under the PCAM is limited to six percent of  
21 PacifiCorp's revenues in the preceding calendar year.<sup>61</sup> As a result, the

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<sup>60</sup> Order No. 20-476 at 30 (Dec. 18, 2020).

<sup>61</sup> *In the matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 14–15 (Dec. 20, 2012).



1 PCAM does not fully mitigate the power cost risk for PacifiCorp. This is  
2 important to investors because fuel and purchased power costs typically  
3 account for 50–60 percent of the total operating costs for a regulated utility.  
4 Moreover, according to SNL Financial, there are only nine states (*i.e.*,  
5 Arizona, Hawaii, Idaho, Missouri, Montana, Oregon, Vermont, Washington,  
6 and Wyoming) that have fuel cost recovery mechanisms with sharing bands.  
7 The remaining 41 states either have restructured and the electric utilities do  
8 not own generation or have fuel cost recovery mechanisms with a true-up  
9 between actual and forecasted fuel costs.

10 In addition, approximately 88 percent of the operating companies held  
11 by the proxy group are allowed to pass through fuel costs and purchased  
12 power costs directly to customers, without deadbands, sharing bands and  
13 earnings tests.

14 2. Test Year Convention: PacifiCorp is using a test period that forecasts  
15 expenses through the test year 2023, however plant related balances are as of  
16 year-end 2022. As shown in Exhibit PAC/310, 50.00 percent of the operating  
17 companies held by the proxy group provide service in jurisdictions use a fully  
18 or partially forecast test year.

19 3. Rate Base: The Company's rate base in this proceeding is established using  
20 year-end 2022 balances for plant-related rate base, other adjusted rate base  
21 balances are based on the 13-month average as of December 31, 2023.  
22 Approximately 45 percent of the operating subsidiaries held by the proxy  
23 group use year-end rate base, meaning that the rate base includes capital

1 additions that occurred in the second half of the test year and is more  
2 reflective of net utility plant going forward.

3 4. Volumetric Risk/Decoupling: PacifiCorp does not have protection against  
4 volumetric risk in Oregon. In contrast, approximately 49 percent of the  
5 operating companies held by the proxy group have some form of protection  
6 against volumetric risk through either a partial or full revenue decoupling  
7 mechanism that mitigates the effect of fluctuations in volume on revenues.

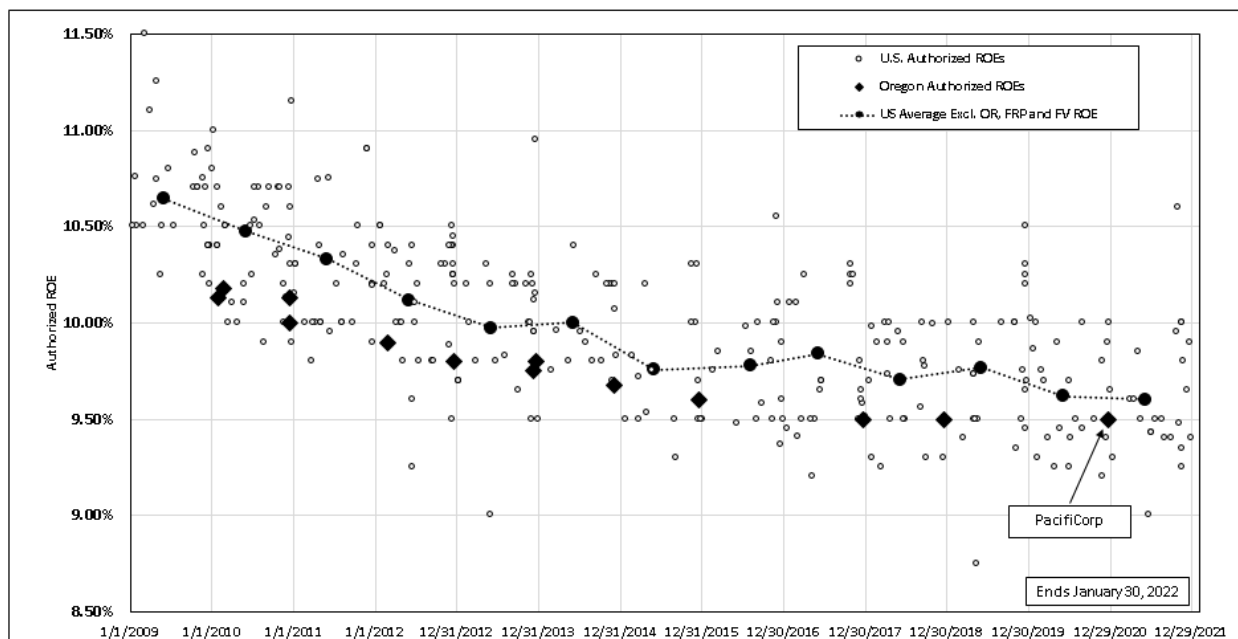
8 5. Capital Cost Recovery: PacifiCorp is authorized to separately file to recover  
9 capital costs to construct or otherwise acquire renewable generation facilities  
10 and the associated transmission. However, utilities in Oregon are prohibited  
11 by law from the inclusion of construction work in progress in rate base, and  
12 deferred accounting is not available for recovery of capital expenditures. By  
13 comparison, approximately 52 percent of the operating companies held by the  
14 proxy group also have some form of capital cost recovery mechanism in place  
15 that allows for recovery of capital costs between rate cases.

16 **Q. How do recent returns in Oregon compare to the authorized returns in other**  
17 **jurisdictions?**

18 A. As noted in RRA's evaluation above, the authorized ROEs for electric and natural gas  
19 utilities in Oregon, while largely the result of settlement agreements approved by the  
20 Commission, have been below the prevailing industry average for electric and natural  
21 gas utilities across the U.S. Figure 13 below shows the authorized returns for  
22 vertically integrated electric utilities in other jurisdictions since January 2009, and the  
23 returns authorized in Oregon for electric companies. As shown in Figure 13, the

1 authorized returns for electric utilities in Oregon have been at the low end of the range  
2 of authorized ROEs in other state jurisdictions for 2015 through 2021.

3 **Figure 13: Comparison of Oregon and U.S. Authorized Electric Returns<sup>62</sup>**



4 **Q. Is there any reason that the Commission should be concerned about authorizing**  
5 **equity returns that are at the low end of the range established by other state**  
6 **regulatory jurisdictions?**

7 A. Yes. Credit rating agencies take the authorized ROE into consideration in the overall  
8 risk analysis of a company. Therefore, to the extent that the returns in a jurisdiction  
9 are lower than the returns that have been authorized more broadly, credit rating  
10 agencies will consider this in the overall risk assessment of the regulatory jurisdiction  
11 in which the company operates. Moody's downgraded ALLETE, Inc. from A3 to  
12 Baa1 primarily based on the less than favorable outcome in Minnesota Power's last

<sup>62</sup> Source: Capital IQ. Data excludes states where ROE is established based on a formula (Illinois and Vermont) and Arizona which relies on a fair value ROE.

1 fully litigated rate case in Minnesota which included what Moody's noted was a  
2 below average authorized ROE of 9.25 percent.<sup>63</sup> In addition, FitchRatings  
3 downgraded CenterPoint Energy Houston Electric's Long-Term Issuer Default rating  
4 from A- to BBB+ and revised the rating outlook from Stable to Negative following  
5 an unfavorable outcome in a recent rate case in Texas.<sup>64</sup> Finally, FitchRatings  
6 recently downgraded and maintained a negative outlook for Arizona Public Service  
7 Company (APS) and its parent, Pinnacle West Capital Corporation, following the  
8 hearings conducted by the Arizona Corporation Commission (ACC) in October 2021  
9 regarding APS' current rate case proceeding.<sup>65</sup> While the ACC had not issued a final  
10 order in APS' rate case at the time, FitchRatings noted that the developments at the  
11 hearing in October indicate a likely credit negative outcome that will negatively affect  
12 the financial metrics of both APS and Pinnacle West Capital Corporation. It is also  
13 important to note that Moody's recently placed both APS and Pinnacle West Capital  
14 Corporation on review for downgrade following the ACC hearing in October.<sup>66</sup>

15 PacifiCorp must compete for capital with other utilities and businesses.  
16 Placing PacifiCorp at the lower end of authorized ROEs outside Oregon over the  
17 longer term could negatively impact its access to capital.

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<sup>63</sup> MOODY'S INVESTOR SERVICE, Credit Opinion: ALLETE, Inc. Update following downgrade at 3 (Apr. 3, 2019).

<sup>64</sup> FITCHRATINGS, Fitch Downgrades CenterPoint Energy Houston Electric to BBB+; Affirms CNP; Outlooks Negative (Feb. 19, 2020).

<sup>65</sup> FITCHRATINGS, Fitch Downgrades Pinnacle West Capital & Arizona Public Service to 'BBB+'; Outlooks Remain Negative (Oct. 12, 2021).

<sup>66</sup> MOODY'S INVESTORS SERVICE, Rating Actions: Moody's places Pinnacle West and Arizona Public Service ratings on review for downgrade (Oct. 12, 2021).

1 **Q. How should the Commission use the information regarding authorized ROEs in**  
2 **other jurisdictions in determining the ROE for PacifiCorp?**

3 A. As discussed above, the companies in the proxy group operate in multiple  
4 jurisdictions across the U.S. Since PacifiCorp must compete directly for capital with  
5 investments of similar risk, it is appropriate to review the authorized ROEs in other  
6 jurisdictions. The comparison is important because investors are considering the  
7 authorized returns across the U.S. and are likely to invest equity in those utilities with  
8 the highest returns. Furthermore, investors are also likely to consider business and  
9 financial risks for a company like PacifiCorp which faces increased risk as a result of  
10 the Company's capital expenditure plan and limited cost recovery mechanisms.  
11 Therefore, authorizing an ROE for PacifiCorp that is equivalent to the average  
12 authorized ROE for other vertically integrated electric utilities is not sufficient to  
13 compensate investors for the added risk of PacifiCorp. As such, it is important that  
14 the Commission consider, as I have in my recommendation, the additional risk of  
15 PacifiCorp and place the authorized ROE for PacifiCorp towards the high end of  
16 authorized ROEs for other vertically integrated electric utilities.

17 **Q. What are your conclusions regarding the perceived risks related to the Oregon**  
18 **regulatory environment?**

19 A. As discussed throughout this section of my testimony, both Moody's and S&P have  
20 identified the supportiveness of the regulatory environment as an important  
21 consideration in developing their overall credit ratings for regulated utilities.  
22 Considering the regulatory adjustment mechanisms, many of the companies in the  
23 proxy group have more timely cost recovery through fuel cost recovery mechanisms,

1 fully forecasted test years, year-end rate base in all cases, capital cost recovery  
2 trackers, and revenue stabilization mechanisms than PacifiCorp has in Oregon.  
3 Additionally, authorized ROEs in Oregon have been below the average authorized  
4 ROEs for electric and gas utilities across the U.S. For these reasons, I conclude that  
5 the authorized ROE for PacifiCorp should be higher than the proxy group mean.

6 **C. Generation Ownership**

7 **Q. How does the business risk of vertically integrated electric utilities compare to**  
8 **the business risk of other regulated utilities?**

9 A. According to Moody's, generation ownership causes vertically integrated electric  
10 utilities to have higher business risk than either electric transmission and distribution  
11 companies, or natural gas distribution or transportation companies.<sup>67</sup> As a result of  
12 this higher business risk, integrated electric utilities typically require a higher ROE or  
13 percentage of equity in the capital structure than other electric or gas utilities.

14 **Q. Are there other risk factors specific to vertically integrated electric utilities that**  
15 **the credit rating agencies consider when determining the credit rating of a**  
16 **company that owns generation?**

17 A. Yes. As discussed above, Moody's establishes credit ratings based on four key  
18 factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3)  
19 diversification; and (4) financial strength, liquidity and key financial metrics. The  
20 third factor diversification, which Moody's assigns a 10.00 percent weighting in the  
21 overall assessments of a company's business risk, considers the fuel source diversity

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<sup>67</sup> MOODY'S INVESTORS SERVICE, *Rating Methodology: Regulated Electric and Gas Utilities* at 21-22 (Jun. 23, 2017).

1 of a utility with generation. Moody's notes:

2 For utilities with electric generation, fuel source diversity can  
3 mitigate the impact (to the utility and to its rate-payers) of changes  
4 in commodity prices, hydrology and water flow, and environmental  
5 or other regulations affecting plant operations and economics. We  
6 have observed that utilities' regulatory environments are most likely  
7 to become unfavorable during periods of rapid rate increases (which  
8 are more important than absolute rate levels) and that fuel diversity  
9 leads to more stable rates over time.

10 For that reason, fuel diversity can be important even if fuel and  
11 purchased power expenses are an automatic pass-through to the  
12 utility's ratepayers. Changes in environmental, safety and other  
13 regulations have caused vulnerabilities for certain technologies and  
14 fuel sources during the past five years. These vulnerabilities have  
15 varied widely in different countries and have changed over time.<sup>68</sup>

16 **Q. Have you conducted an analysis to compare the fuel sources for the generation**  
17 **portfolio of PacifiCorp to the companies in your proxy group?**

18 A. Yes, I have. Specifically, I calculated for PacifiCorp, and each company in the proxy  
19 group, the percentage of regulated owned generation capacity that was derived from  
20 one of the following fuel sources: oil/natural gas, coal, nuclear, hydro, and other. As  
21 shown in Figure 14, approximately 57.83 percent of PacifiCorp's regulated, owned  
22 generation came from coal-fired power plants with approximately 82.24 percent  
23 coming from either oil, natural gas, or coal-fired power plants. Therefore, PacifiCorp  
24 is more reliant on a limited number of fuel sources for its regulated generation and  
25 overall slightly less diversified than the companies in the proxy group.

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<sup>68</sup> *Id.* at 16.

1 **Figure 14: Regulated Owned Generation Capacity - Fuel Mix for PacifiCorp and Proxy**  
2 **Group<sup>69</sup>**

Company	Ticker	Oil & Natural Gas	Coal	Nuclear	Hydro	Other	Total Regulated Generation Mix
ALLETE, Inc.	ALE	5.37%	51.59%	0.00%	7.54%	35.49%	100.00%
Alliant Energy Corporation	LNT	49.67%	27.56%	0.00%	0.70%	22.08%	100.00%
Ameren Corporation	AEE	30.96%	49.46%	11.03%	7.28%	1.27%	100.00%
American Electric Power Company, Inc.	AEP	35.18%	50.18%	9.78%	3.71%	1.15%	100.00%
Avista Corporation	AVA	33.44%	10.38%	0.00%	53.80%	2.37%	100.00%
CMS Energy Corporation	CMS	49.02%	21.78%	0.00%	19.04%	10.17%	100.00%
Duke Energy Corporation	DUK	46.29%	28.50%	17.00%	6.44%	1.77%	100.00%
Entergy Corporation	ETR	72.79%	11.17%	15.66%	0.29%	0.10%	100.00%
Eversource Energy	EVER	34.48%	50.43%	10.06%	0.05%	4.99%	100.00%
IDACORP, Inc.	IDA	22.37%	22.73%	0.00%	54.90%	0.00%	100.00%
NextEra Energy, Inc.	NEE	76.09%	4.10%	10.59%	0.00%	9.23%	100.00%
NorthWestern Corporation	NWE	24.28%	32.39%	0.00%	33.60%	9.73%	100.00%
Otter Tail Corporation	OTTR	34.77%	37.92%	0.00%	0.39%	26.92%	100.00%
<b>PacifiCorp</b>	<b>PacifiCorp</b>	<b>24.41%</b>	<b>57.83%</b>	<b>0.00%</b>	<b>17.76%</b>		<b>100.00%</b>
Portland General Electric Company	POR	55.38%	8.36%	0.00%	13.03%	23.24%	100.00%
Southern Company	SO	48.84%	29.41%	11.55%	9.05%	1.15%	100.00%
Xcel Energy Inc.	XEL	40.74%	29.61%	7.96%	2.50%	19.19%	100.00%

3 **Q. Is PacifiCorp’s generation portfolio currently in a state of transition?**

4 A. Yes. As further discussed in the testimony of Ms. Joelle R. Steward, the Company is  
5 responding to changing market conditions and, as indicated by the 2019 and 2021  
6 Integrated Resource Plans (IRPs), is taking near term actions to retire certain coal  
7 units, invest in new renewable generation, and invest in associated transmission.

8 **Q. What are your conclusions regarding the perceived risks related to the fuel mix**  
9 **of PacifiCorp’s generation portfolio?**

10 A. PacifiCorp’s fossil-fuel generation is subject to increased environmental regulations  
11 aimed at cutting power plant emissions. The environmental regulations pose  
12 additional business risk as sizable future capital expenditures may be required to  
13 comply with regulations. Furthermore, the Company recently outlined plans for  
14 reshaping its generation portfolio. While the Company intends to improve fuel

<sup>69</sup> PacifiCorp’s generation includes approximately 3,010 megawatts (MW) of wind generation, or approximately 12.25 percent of the portfolio. This generation is included in the combined percentage for “Hydro and Other” for comparison purposes with the proxy group data.



1 diversity over the long-run, the plans will require continued access to capital markets  
2 to finance the new investments. The Company's existing generation portfolio and  
3 proposed transmission and generation investment plans increase the overall risk  
4 profile as compared with the proxy group.

5 **Q. Based on these analyses, what is your conclusion regarding the level of**  
6 **regulatory risk for the Company's operations relative to that of the proxy group**  
7 **companies?**

8 A. As discussed, the ratemaking conventions used to develop the Company's rates and  
9 the mechanism used for the recovery of its costs are generally consistent with those  
10 relied upon by the majority of the utility operating subsidiaries of the proxy group  
11 companies.

12 **D. Impact of Climate Change Initiatives**

13 **Q. Has Oregon enacted legislation that increases the Company's business risk going**  
14 **forward?**

15 A. Yes. In 2021 Oregon enacted House Bill 2021 which requires that retail electricity  
16 providers reduce greenhouse gas (GHG) emissions associated with electricity sold to  
17 Oregon consumers by 80 percent below baseline emission levels by 2030, 90 percent  
18 reductions below baseline emissions levels by 2035, and 100 percent below baseline  
19 emissions levels by 2040.<sup>70</sup>

20 **Q. Has PacifiCorp established a plan with respect to the reduction of GHG**  
21 **emissions?**

22 A. Yes. Over time, through the 2017, 2019 and 2021 IRPs, PacifiCorp has outlined its

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<sup>70</sup> S&P Capital IQ, Commission Review accessed January 19, 2022.

1 plans to substantially increase renewable energy capacity and to upgrade the  
2 transmission network connecting supply with demand. The Company's 2021 IRP  
3 identifies critical investments in transmission, renewable energy, storage, demand  
4 response and advanced nuclear resources to meet its environmental goals. Over the  
5 period from 2021 through 2040, the Company plans to reduce demand by 4,290 MW  
6 through energy efficiency programs, increase solar resources by 5,628 MW, increase  
7 wind resources by 3,628 MW and add 6,181 MW of storage resources. Further, the  
8 Company plans 2,448 MW of direct load control programs and 500-1500 MW of  
9 advanced nuclear technology.<sup>71</sup>

10 **Q. Has the Company identified plans to retire coal-fired generation to meet GHG**  
11 **reduction requirements?**

12 A. Yes. The Company recently completed a coal-to-gas peaking generation conversion  
13 of Naughton Unit 3 in Wyoming and retired the Cholla Unit 4 generator in Arizona.  
14 In addition, over the next four years, the Company plans to begin the retirement or  
15 divestiture of Colstrip Units 3 and 4 in Montana, and Naughton Units 1 and 2.  
16 Further, the Company plans a coal-to-gas peaking conversion for Jim Bridger Units 1  
17 and 2 in Wyoming<sup>72</sup>

18 **Q. How much conservation and demand response is planned over the near-term,**  
19 **when the rates set in this proceeding are likely to be in effect?**

20 A. The Company is planning 603 MW of energy efficiency and 549 MW of demand  
21 response between 2021 and 2024.

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<sup>71</sup> PacifiCorp 2021 IRP at 2.

<sup>72</sup> *Id.* at 4.

1 **Q. Have the credit rating agencies comments on PacifiCorp’s capital spending plans?**

2 A. Yes. S&P has noted that continued regulatory support will be important to sustain  
3 credit quality as the Company implements its ever increasing renewable and  
4 transmission plan. Further S&P noted that the Company’s metrics have been  
5 impacted by negative cash flow impacts of federal tax reform and the associated loss  
6 of bonus depreciation as well as regulatory lag and other events. Further, S&P  
7 expects that heightened capital expenditures will maintain downward pressure on  
8 credit metrics and to be funded with a mixture of debt and retained cash flow that will  
9 continue to support credit quality.<sup>73</sup>

10 **Q. What are your overall conclusions regarding the Company’s business risks**  
11 **related to GHG emission reduction initiatives in Oregon?**

12 A. The Company is embarking on plans to meet the GHG emissions requirements  
13 established in House Bill 2021 that include significant demand reduction, retirements  
14 of generating assets and capital investment plans that include renewable resources  
15 and transmission investment that continue to provide customers with safe and reliable  
16 service. In order to meet these objectives in a manner that is least cost and lowest  
17 risk, which benefits customers, it is necessary that the ROE and equity ratio that are  
18 authorized in this proceeding support the Company’s core financial metrics. The  
19 Company’s proposed ROE and equity ratio would provide that necessary support.

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<sup>73</sup> MOODY’S INVESTORS SERVICE, *Credit Opinion, PacifiCorp Update to credit analysis* (Jun. 30, 2021).

1 **IX. CAPITAL STRUCTURE**

2 **Q. Is the capital structure of the Company an important consideration in the**  
3 **determination of the appropriate ROE?**

4 A. Yes. All else equal, a higher debt ratio increases the risk to investors. For debt  
5 holders, higher debt ratios result in a greater portion of the available cash flow being  
6 required to meet debt service, thereby increasing the risk associated with the  
7 payments on debt. The result of increased risk is a higher interest rate. The  
8 incremental risk of a higher debt ratio is more significant for common equity  
9 shareholders, who are the residual claimants on the cash flow of the Company.  
10 Therefore, the greater the debt service requirement, the less cash flow is available for  
11 common equity holders.

12 **Q. What is PacifiCorp's proposed capital structure?**

13 A. As discussed in the direct testimony of Company witness Ms. Nikki L. Kobliha,  
14 PacifiCorp is proposing a capital structure that is composed of 52.25 percent common  
15 equity, 0.01 percent preferred stock and 47.74 percent long-term debt.

16 **Q. Have you analyzed the capital structures of the proxy group companies?**

17 A. Yes. I calculated the percentages of common equity, long-term debt and short-term  
18 debt over the most recent two years for each of the utility operating subsidiaries of the  
19 proxy group companies. Because the cost of equity is established based on the return  
20 that is derived from the risk-comparable proxy group, it is reasonable to look to the  
21 proxy group average capital structure to benchmark the equity ratio for the Company.  
22 As shown in PAC/311, the equity ratios for the utility operating subsidiaries of the  
23 proxy group range from 46.85 percent to 61.11 percent, with a median of 52.71

1 percent in the most recent year. PacifiCorp's proposed equity ratio of 52.25 percent  
2 is within the range of equity ratios of the proxy group. Accordingly, I consider the  
3 proposed equity ratios to be reasonable.

4 **Q. Is there a relationship between the equity ratio and the authorized ROE?**

5 A. Yes. As noted by the Commission in the Company's last rate proceeding, there is a  
6 relationship between the equity ratio and the return on equity.<sup>74</sup> The equity ratio is  
7 the primary indicator of financial risk for a regulated utility such as PacifiCorp. To  
8 the extent the equity ratio is reduced, it is necessary to increase the authorized ROE to  
9 compensate investors for the greater financial risk associated with a lower equity  
10 ratio.

11 **Q. Will the capital structure and ROE authorized in this proceeding affect the**  
12 **Company's access to capital at reasonable rates?**

13 A. Yes. The level of earnings authorized by the Commission directly affects the  
14 Company's ability to fund its operations with internally generated funds. Both bond  
15 investors and rating agencies expect a significant portion of ongoing capital  
16 investments to be financed with internally generated funds. In addition, it is  
17 important to recognize that because a utility's investment horizon is very long,  
18 investors require the assurance of a sufficiently high return to satisfy the long-run  
19 financing requirements of the assets placed into service. Those assurances, which  
20 often are measured by the relationship between internally generated cash flows and  
21 debt (or interest expense), depend quite heavily on the capital structure. As a  
22 consequence, both the ROE and capital structure are very important to debt and

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<sup>74</sup> Order No. 20-476 at 31(fn 135).

1 equity investors. Furthermore, considering the capital market conditions discussed in  
2 Section V, the authorized ROE and capital structure take on even greater significance.

3 **X. CONCLUSIONS AND RECOMMENDATION**

4 **Q. What is your conclusion regarding a fair ROE for PacifiCorp?**

5 A. As discussed throughout my testimony, the authorized ROE should be a forward-  
6 looking estimate; therefore, the analyses supporting my recommendation rely on  
7 forward-looking inputs and assumptions (*e.g.*, projected earnings growth rates in the  
8 DCF model, forecasted risk-free rate and market risk premium in the CAPM  
9 analyses) and take into consideration capital market conditions, including the  
10 expected increasing interest rate environment and the underperformance of utility  
11 stocks as the economy emerges from the pandemic. The authorized ROE should also  
12 consider the relative regulatory, business, and financial risks of PacifiCorp compared  
13 to the proxy group.

14 As discussed previously, the cost of equity ranges from 9.90 percent to  
15 10.75 percent considering the results of all of the models presented in Figure 14.  
16 Within this range, taking into consideration current and projected capital market  
17 conditions, as well as the specific risk factors discussed for PacifiCorp, I conclude  
18 that the Company's requested ROE of 9.80 percent is conservative.

1

**Figure 14: Summary of Results**

<b><i>Constant Growth- Median DCF</i></b>			
	Median Low	Median	Median High
30-Day Average	8.57%	9.44%	10.34%
90-Day Average	8.62%	9.50%	10.37%
180-Day Average	8.63%	9.35%	10.28%
Constant Growth Median	8.61%	9.43%	10.33%
<b><i>Multi-Stage DCF-Median Results</i></b>			
30-Day Average	9.01%	9.45%	9.79%
90-Day Average	9.03%	9.50%	9.81%
180-Day Average	9.02%	9.48%	9.73%
Multi-Stage Median	9.02%	9.48%	9.78%
<b><i>CAPM</i></b>			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.28%	11.36%	11.47%
Bloomberg Beta	10.56%	10.68%	10.85%
Long-Term Avg. Beta	9.72%	9.90%	10.14%
<b><i>Risk Premium</i></b>			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	9.47%	9.75%	10.13%

2 **Q. What is your conclusion with respect to PacifiCorp’s requested capital**  
3 **structure?**

4 A. My conclusion is that PacifiCorp’s requested capital structure consisting of  
5 52.25 percent common equity, 47.74 percent long-term debt and 0.01 preferred equity  
6 is reasonable.

7 **Q. Does this conclude your direct testimony?**

8 A. Yes.

Docket No. UE 399  
Exhibit PAC/301  
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Ann E. Bulkley  
Resume and Testimony Listing of Ann E. Bulkley**

**March 2022**



# Ann E. Bulkley

## PRINCIPAL

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Boston

508.981.0866

[Ann.Bulkley@brattle.com](mailto:Ann.Bulkley@brattle.com)

With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas sectors, including rate of return, cost of equity, 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 nearly 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.

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### AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

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## EDUCATION

- **Boston University**  
MA in Economics
- **Simmons College**  
BA in Economics and Finance

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## 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

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## 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 several 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.



- 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 approaches. 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.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost, and comparable sales approaches.
- 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 for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- 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.

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
<b>Arizona Corporation Commission</b>				
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
<b>Arkansas Public Service Commission</b>				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity



SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
<b>California Public Utilities Commission</b>				
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity
<b>Colorado Public Utilities Commission</b>				
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
<b>Connecticut Public Utilities Regulatory Authority</b>				
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
<b>Federal Energy Regulatory Commission</b>				
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
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
<b>Idaho Public Utilities Commission</b>				
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
<b>Illinois Commerce Commission</b>				
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
<b>Indiana Utility Regulatory Commission</b>				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
<b>Iowa Department of Commerce Utilities Board</b>				
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
<b>Kansas Corporation Commission</b>				



SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
<b>Kentucky Public Service Commission</b>				
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
<b>Maine Public Utilities Commission</b>				
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
<b>Maryland Public Service Commission</b>				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
<b>Massachusetts Appellate Tax Board</b>				
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
<b>Massachusetts Department of Public Utilities</b>				
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
<b>Michigan Public Service Commission</b>				
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
<b>Michigan Tax Tribunal</b>				
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
<b>Minnesota Public Utilities Commission</b>				
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
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
<b>Missouri Public Service Commission</b>				
Evergy Missouri West	1/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Evergy Missouri Metro	1/22	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
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
<b>Montana Public Service Commission</b>				
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
<b>New Hampshire - Board of Tax and Land Appeals</b>				
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
<b>New Hampshire Public Utilities Commission</b>				
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
<b>New Hampshire-Merrimack County Superior Court</b>				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
<b>New Hampshire-Rockingham Superior Court</b>				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
<b>New Jersey Board of Public Utilities</b>				
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
<b>New Mexico Public Regulation Commission</b>				
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
<b>New York State Department of Public Service</b>				
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
<b>North Dakota Public Service Commission</b>				
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
<b>Oklahoma Corporation Commission</b>				
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
<b>Oregon Public Service Commission</b>				
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
<b>Pennsylvania Public Utility Commission</b>				
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
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
<b>South Dakota Public Utilities Commission</b>				
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
<b>Texas Public Utility Commission</b>				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
<b>Utah Public Service Commission</b>				
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
<b>Virginia State Corporation Commission</b>				
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
<b>Washington Utilities Transportation Commission</b>				
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
<b>West Virginia Public Service Commission</b>				
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
<b>Wisconsin Public Service Commission</b>				
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



SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
<b>Wyoming Public Service Commission</b>				
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

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CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts and the State of New Hampshire



Docket No. UE 399  
Exhibit PAC/302  
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Ann E. Bulkley  
Summary of Results**

**March 2022**

SUMMARY OF ROE RESULTS AS OF DECEMBER 31, 2022

<b>Constant Growth- Median DCF</b>			
	Median Low	Median	Median High
30-Day Average	8.57%	9.44%	10.34%
90-Day Average	8.62%	9.50%	10.37%
180-Day Average	8.63%	9.35%	10.28%
Constant Growth Median	8.61%	9.43%	10.33%
<b>Multi-Stage DCF-Median Results</b>			
30-Day Average	9.01%	9.45%	9.79%
90-Day Average	9.03%	9.50%	9.81%
180-Day Average	9.02%	9.48%	9.73%
Multi-Stage Median	9.02%	9.48%	9.78%
<b>CAPM</b>			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.28%	11.36%	11.47%
Bloomberg Beta	10.56%	10.68%	10.85%
Long-Term Avg. Beta	9.72%	9.90%	10.14%
<b>Risk Premium</b>			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	9.47%	9.75%	10.13%

Docket No. UE 399  
Exhibit PAC/303  
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Ann E. Bulkley  
Proxy Group Selection**

**March 2022**

PROXY GROUP SCREENING DATA AND RESULTS - FINAL PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Company	Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	Generation Assets Included in Rate Base	% Regulated Coal Generation Capacity > 5%	% Regulated Operating Income > 60%	% Regulated Electric Operating Income ≥ 60%	Announced Merger	
ALLETE, Inc.	ALE	Yes	BBB+	Yes	Yes	Yes	49.92%	75.0%	97.4%	No
Alliant Energy Corporation	LNT	Yes	A-	Yes	Yes	Yes	32.27%	96.9%	93.9%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	49.97%	100.0%	88.3%	No
American Electric Power Company, Inc.	AEP	Yes	A-	Yes	Yes	Yes	51.92%	95.6%	100.0%	No
Avista Corporation	AVA	Yes	BBB	Yes	Yes	Yes	10.41%	100.0%	100.0%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	Yes	23.18%	93.8%	74.2%	No
Duke Energy Corporation	DUK	Yes	A-	Yes	Yes	Yes	27.95%	100.0%	93.1%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	Yes	13.07%	100.0%	98.9%	No
Evergy, Inc.	EVRG	Yes	A-	Yes	Yes	Yes	50.00%	100.0%	100.0%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	Yes	26.43%	98.9%	100.0%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	Yes	Yes	8.56%	70.0%	100.0%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	Yes	32.54%	99.9%	84.4%	No
Otter Tail Corporation	OTTR	Yes	BBB	Yes	Yes	Yes	66.95%	73.5%	100.0%	No
Portland General Electric Company	POR	Yes	BBB+	Yes	Yes	Yes	20.81%	100.0%	100.0%	No
Southern Company	SO	Yes	A-	Yes	Yes	Yes	32.58%	95.7%	81.3%	No
Xcel Energy Inc.	XEL	Yes	A-	Yes	Yes	Yes	32.85%	100.0%	87.5%	No

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional

[3] Source: Yahoo! Finance and Zacks

[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks

[5] to [6] Source: SNL Financial

[7] to [8] Source: Form 10-Ks for 2018, 2019 & 2020

[9] SNL Financial News Releases

Docket No. UE 399  
Exhibit PAC/304  
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Ann E. Bulkley  
Constant Growth Discounted Cash Flow Model**

**March 2022**

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	\$2.52	\$63.13	3.99%	4.10%	5.00%	5.67%	6.00%	5.56%	9.09%	9.66%	10.11%
Alliant Energy Corporation	LNT	\$1.61	\$58.59	2.75%	2.83%	5.50%	6.10%	6.10%	5.90%	8.32%	8.73%	8.93%
Ameren Corporation	AEE	\$2.20	\$86.40	2.55%	2.64%	6.50%	7.90%	7.50%	7.30%	9.13%	9.94%	10.55%
American Electric Power Company, Inc.	AEP	\$3.12	\$84.96	3.67%	3.78%	6.50%	5.50%	5.70%	5.90%	9.27%	9.68%	10.29%
Avista Corporation	AVA	\$1.69	\$40.41	4.18%	4.28%	3.00%	6.20%	5.10%	4.77%	7.24%	9.05%	10.51%
CMS Energy Corporation	CMS	\$1.74	\$62.53	2.78%	2.87%	6.00%	5.62%	7.00%	6.21%	8.48%	9.08%	9.88%
Duke Energy Corporation	DUK	\$3.94	\$101.53	3.88%	3.98%	7.00%	2.50%	5.30%	4.93%	6.43%	8.91%	11.02%
Entergy Corporation	ETR	\$4.04	\$107.27	3.77%	3.85%	3.00%	6.00%	n/a	4.50%	6.82%	8.35%	9.88%
Evergy, Inc.	EVRG	\$2.29	\$66.43	3.45%	3.56%	8.00%	5.12%	6.10%	6.41%	8.66%	9.96%	11.59%
IDACORP, Inc.	IDA	\$3.00	\$109.22	2.75%	2.81%	4.00%	4.40%	4.40%	4.27%	6.80%	7.07%	7.21%
NextEra Energy, Inc.	NEE	\$1.54	\$89.80	1.71%	1.80%	10.50%	9.95%	8.90%	9.78%	10.69%	11.58%	12.30%
NorthWestern Corporation	NWE	\$2.48	\$55.96	4.43%	4.52%	3.00%	4.50%	4.10%	3.87%	7.50%	8.38%	9.03%
Otter Tail Corporation	OTTR	\$1.56	\$68.13	2.29%	2.37%	8.00%	9.00%	4.70%	7.23%	7.04%	9.61%	11.39%
Portland General Electric Company	POR	\$1.72	\$51.06	3.37%	3.50%	7.00%	7.15%	8.60%	7.58%	10.49%	11.08%	12.11%
Southern Company	SO	\$2.64	\$64.96	4.06%	4.18%	6.00%	6.20%	4.90%	5.70%	9.06%	9.88%	10.39%
Xcel Energy Inc.	XEL	\$1.83	\$66.39	2.76%	2.85%	6.00%	6.90%	6.40%	6.43%	8.84%	9.28%	9.75%
Median				3.41%	3.53%	6.00%	6.05%	6.00%	5.90%	8.57%	9.44%	10.34%

[1] Source: Bloomberg Professional, as of December 31, 2020

[2] Source: Bloomberg Professional, equals 30-day average as of December 31, 2021

[3] Equals [1] / [2]

[4] Source: Bloomberg Professional

[4] Source: Value Line

[5] Source: Value Line

[5] Source: Value Line

[5] Source: Value Line

[6] Source: Yahoo! Finance

[7] Source: Zacks

[7] Source: SNL Financial

[8] Equals Average ([5], [6], [7])

[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])

[10] Equals [4] + [8]

[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF -- OR PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	\$2.52	\$62.93	4.00%	4.12%	5.00%	5.67%	6.00%	5.56%	9.10%	9.67%	10.12%
Alliant Energy Corporation	LNT	\$1.61	\$57.81	2.78%	2.87%	5.50%	6.10%	6.10%	5.90%	8.36%	8.77%	8.97%
Ameren Corporation	AEE	\$2.20	\$85.14	2.58%	2.68%	6.50%	7.90%	7.50%	7.30%	9.17%	9.98%	10.59%
American Electric Power Company, Inc.	AEP	\$3.12	\$84.99	3.67%	3.78%	6.50%	5.50%	5.70%	5.90%	9.27%	9.68%	10.29%
Avista Corporation	AVA	\$1.69	\$40.38	4.19%	4.29%	3.00%	6.20%	5.10%	4.77%	7.25%	9.05%	10.52%
CMS Energy Corporation	CMS	\$1.74	\$61.76	2.82%	2.90%	6.00%	5.62%	7.00%	6.21%	8.52%	9.11%	9.92%
Duke Energy Corporation	DUK	\$3.94	\$101.55	3.88%	3.98%	7.00%	2.50%	5.30%	4.93%	6.43%	8.91%	11.02%
Entergy Corporation	ETR	\$4.04	\$106.25	3.80%	3.89%	3.00%	6.00%	n/a	4.50%	6.86%	8.39%	9.92%
Evergy, Inc.	EVRG	\$2.29	\$65.27	3.51%	3.62%	8.00%	5.12%	6.10%	6.41%	8.72%	10.03%	11.65%
IDACORP, Inc.	IDA	\$3.00	\$106.01	2.83%	2.89%	4.00%	4.40%	4.40%	4.27%	6.89%	7.16%	7.29%
NextEra Energy, Inc.	NEE	\$1.54	\$85.45	1.80%	1.89%	10.50%	9.95%	8.90%	9.78%	10.78%	11.67%	12.40%
NorthWestern Corporation	NWE	\$2.48	\$58.26	4.26%	4.34%	3.00%	4.50%	4.10%	3.87%	7.32%	8.21%	8.85%
Otter Tail Corporation	OTTR	\$1.56	\$62.00	2.52%	2.61%	8.00%	9.00%	4.70%	7.23%	7.28%	9.84%	11.63%
Portland General Electric Company	POR	\$1.72	\$49.88	3.45%	3.58%	7.00%	7.15%	8.60%	7.58%	10.57%	11.16%	12.20%
Southern Company	SO	\$2.64	\$64.12	4.12%	4.23%	6.00%	6.20%	4.90%	5.70%	9.12%	9.93%	10.44%
Xcel Energy Inc.	XEL	\$1.83	\$65.47	2.80%	2.89%	6.00%	6.90%	6.40%	6.43%	8.88%	9.32%	9.79%
Median				3.48%	3.60%	6.00%	6.05%	6.00%	5.90%	8.62%	9.50%	10.37%

[1] Source: Bloomberg Professional, as of December 31, 2020

[2] Source: Bloomberg Professional, equals 90-day average as of December 31, 2021

[3] Equals [1] / [2]

[4] Source: Bloomberg Professional

[4] Source: Value Line

[5] Source: Value Line

[5] Source: Value Line

[5] Source: Value Line

[6] Source: Yahoo! Finance

[7] Source: Zacks

[7] Source: SNL Financial

[8] Equals Average ([5], [6], [7])

[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])

[10] Equals [4] + [8]

[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF -- OR PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	\$2.52	\$66.46	3.79%	3.90%	5.00%	5.67%	6.00%	5.56%	8.89%	9.45%	9.91%
Alliant Energy Corporation	LNT	\$1.61	\$57.87	2.78%	2.86%	5.50%	6.10%	6.10%	5.90%	8.36%	8.76%	8.97%
Ameren Corporation	AEE	\$2.20	\$84.84	2.59%	2.69%	6.50%	7.90%	7.50%	7.30%	9.18%	9.99%	10.60%
American Electric Power Company, Inc.	AEP	\$3.12	\$85.87	3.63%	3.74%	6.50%	5.50%	5.70%	5.90%	9.23%	9.64%	10.25%
Avista Corporation	AVA	\$1.69	\$42.34	3.99%	4.09%	3.00%	6.20%	5.10%	4.77%	7.05%	8.85%	10.32%
CMS Energy Corporation	CMS	\$1.74	\$62.01	2.81%	2.89%	6.00%	5.62%	7.00%	6.21%	8.50%	9.10%	9.90%
Duke Energy Corporation	DUK	\$3.94	\$102.02	3.86%	3.96%	7.00%	2.50%	5.30%	4.93%	6.41%	8.89%	11.00%
Entergy Corporation	ETR	\$4.04	\$106.04	3.81%	3.90%	3.00%	6.00%	n/a	4.50%	6.87%	8.40%	9.92%
Evergy, Inc.	EVRG	\$2.29	\$64.59	3.55%	3.66%	8.00%	5.12%	6.10%	6.41%	8.76%	10.07%	11.69%
IDACORP, Inc.	IDA	\$3.00	\$103.97	2.89%	2.95%	4.00%	4.40%	4.40%	4.27%	6.94%	7.21%	7.35%
NextEra Energy, Inc.	NEE	\$1.54	\$80.89	1.90%	2.00%	10.50%	9.95%	8.90%	9.78%	10.89%	11.78%	12.50%
NorthWestern Corporation	NWE	\$2.48	\$60.99	4.07%	4.14%	3.00%	4.50%	4.10%	3.87%	7.13%	8.01%	8.66%
Otter Tail Corporation	OTTR	\$1.56	\$55.71	2.80%	2.90%	8.00%	9.00%	4.70%	7.23%	7.57%	10.13%	11.93%
Portland General Electric Company	POR	\$1.72	\$49.44	3.48%	3.61%	7.00%	7.15%	8.60%	7.58%	10.60%	11.19%	12.23%
Southern Company	SO	\$2.64	\$64.07	4.12%	4.24%	6.00%	6.20%	4.90%	5.70%	9.12%	9.94%	10.45%
Xcel Energy Inc.	XEL	\$1.83	\$67.39	2.72%	2.80%	6.00%	6.90%	6.40%	6.43%	8.80%	9.24%	9.71%
Median				3.51%	3.63%	6.00%	6.05%	6.00%	5.90%	8.63%	9.35%	10.28%

[1] Source: Bloomberg Professional, as of December 31, 2020

[2] Source: Bloomberg Professional, equals 180-day average as of December 31, 2021

[3] Equals [1] / [2]

[4] Source: Bloomberg Professional

[4] Source: Value Line

[5] Source: Value Line

[5] Source: Value Line

[5] Source: Value Line

[6] Source: Yahoo! Finance

[7] Source: Zacks

[7] Source: SNL Financial

[8] Equals Average ([5], [6], [7])

[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])

[10] Equals [4] + [8]

[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])



Docket No. UE 399  
Exhibit PAC/305  
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Ann E. Bulkley  
Multi-Stage Discounted Cash Flow Model**

**March 2022**

**MULTI-STAGE DCF- LOW GROWTH RATE  
STOCK PRICE AVERAGING CONVENTION:**

**30 DAYS**

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (low)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	\$2.52	\$63.13	5.00%	5.08%	5.16%	5.24%	5.32%	5.41%	5.49%	9.76%
Alliant Energy Corporation	LNT	\$1.61	\$58.59	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	8.49%
Ameren Corporation	AEE	\$2.20	\$86.40	6.50%	6.33%	6.16%	5.99%	5.82%	5.66%	5.49%	8.46%
American Electric Power Company, Inc.	AEP	\$3.12	\$84.96	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	9.54%
Avista Corporation	AVA	\$1.69	\$40.41	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.42%
CMS Energy Corporation	CMS	\$1.74	\$62.53	5.62%	5.60%	5.58%	5.55%	5.53%	5.51%	5.49%	8.56%
Duke Energy Corporation	DUK	\$3.94	\$101.53	2.50%	3.00%	3.50%	3.99%	4.49%	4.99%	5.49%	9.00%
Energy Corporation	ETR	\$4.04	\$107.27	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.01%
Evergy, Inc.	EVRG	\$2.29	\$66.43	5.12%	5.18%	5.24%	5.30%	5.36%	5.43%	5.49%	9.19%
IDACORP, Inc.	IDA	\$3.00	\$109.22	4.00%	4.25%	4.50%	4.74%	4.99%	5.24%	5.49%	8.20%
NextEra Energy, Inc.	NEE	\$1.54	\$89.80	8.90%	8.33%	7.76%	7.19%	6.62%	6.06%	5.49%	7.80%
NorthWestern Corporation	NWE	\$2.48	\$55.96	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.67%
Otter Tail Corporation	OTTR	\$1.56	\$68.13	4.70%	4.83%	4.96%	5.09%	5.22%	5.36%	5.49%	7.83%
Portland General Electric Company	POR	\$1.72	\$51.06	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	9.57%
Southern Company	SO	\$2.64	\$64.96	4.90%	5.00%	5.10%	5.19%	5.29%	5.39%	5.49%	9.81%
Xcel Energy Inc.	XEL	\$1.83	\$66.39	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	8.60%
Median					5.13%	5.20%	5.27%	5.34%	5.42%	5.49%	9.01%

**Notes:**

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals 30-trading day average as of December 31, 2021

[3] Source: Exhibit PAC 304

[4] Equals [3] + ([9] - [3]) / 6

[5] Equals [4] + ([9] - [3]) / 6

[6] Equals [5] + ([9] - [3]) / 6

[7] Equals [6] + ([9] - [3]) / 6

[8] Equals [7] + ([9] - [3]) / 6

[9] Source: Exhibit PAC 306

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF- LOW GROWTH RATE  
STOCK PRICE AVERAGING CONVENTION:**

**90 DAYS**

Company		1	2	3	4	5	6	7	8	9	10
		Annualized Dividend	Stock Price	First Stage Growth Rate (low)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	\$2.52	\$62.93	5.00%	5.08%	5.16%	5.24%	5.32%	5.41%	5.49%	9.77%
Alliant Energy Corporation	LNT	\$1.61	\$57.81	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	8.53%
Ameren Corporation	AEE	\$2.20	\$85.14	6.50%	6.33%	6.16%	5.99%	5.82%	5.66%	5.49%	8.50%
American Electric Power Company, Inc.	AEP	\$3.12	\$84.99	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	9.53%
Avista Corporation	AVA	\$1.69	\$40.38	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.42%
CMS Energy Corporation	CMS	\$1.74	\$61.76	5.62%	5.60%	5.58%	5.55%	5.53%	5.51%	5.49%	8.59%
Duke Energy Corporation	DUK	\$3.94	\$101.55	2.50%	3.00%	3.50%	3.99%	4.49%	4.99%	5.49%	9.00%
Energy Corporation	ETR	\$4.04	\$106.25	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.05%
Evergy, Inc.	EVRG	\$2.29	\$65.27	5.12%	5.18%	5.24%	5.30%	5.36%	5.43%	5.49%	9.26%
IDACORP, Inc.	IDA	\$3.00	\$106.01	4.00%	4.25%	4.50%	4.74%	4.99%	5.24%	5.49%	8.28%
NextEra Energy, Inc.	NEE	\$1.54	\$85.45	8.90%	8.33%	7.76%	7.19%	6.62%	6.06%	5.49%	7.92%
NorthWestern Corporation	NWE	\$2.48	\$58.26	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.49%
Otter Tail Corporation	OTTR	\$1.56	\$62.00	4.70%	4.83%	4.96%	5.09%	5.22%	5.36%	5.49%	8.08%
Portland General Electric Company	POR	\$1.72	\$49.88	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	9.66%
Southern Company	SO	\$2.64	\$64.12	4.90%	5.00%	5.10%	5.19%	5.29%	5.39%	5.49%	9.87%
Xcel Energy Inc.	XEL	\$1.83	\$65.47	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	8.65%
Median					5.13%	5.20%	5.27%	5.34%	5.42%	5.49%	9.03%

**Notes:**

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals 90-trading day average as of December 31, 2021

[3] Source: Exhibit PAC 304

[4] Equals  $[3] + ([9] - [3]) / 6$

[5] Equals  $[4] + ([9] - [3]) / 6$

[6] Equals  $[5] + ([9] - [3]) / 6$

[7] Equals  $[6] + ([9] - [3]) / 6$

[8] Equals  $[7] + ([9] - [3]) / 6$

[9] Source: Exhibit PAC 306

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF- LOW GROWTH RATE  
STOCK PRICE AVERAGING CONVENTION:**

**180 DAYS**

Company		1	2	3	4	5	6	7	8	9	10
		Annualized Dividend	Stock Price	First Stage Growth Rate (low)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	\$2.52	\$66.46	5.00%	5.08%	5.16%	5.24%	5.32%	5.41%	5.49%	9.54%
Alliant Energy Corporation	LNT	\$1.61	\$57.87	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	8.53%
Ameren Corporation	AEE	\$2.20	\$84.84	6.50%	6.33%	6.16%	5.99%	5.82%	5.66%	5.49%	8.51%
American Electric Power Company, Inc.	AEP	\$3.12	\$85.87	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	9.49%
Avista Corporation	AVA	\$1.69	\$42.34	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.23%
CMS Energy Corporation	CMS	\$1.74	\$62.01	5.62%	5.60%	5.58%	5.55%	5.53%	5.51%	5.49%	8.58%
Duke Energy Corporation	DUK	\$3.94	\$102.02	2.50%	3.00%	3.50%	3.99%	4.49%	4.99%	5.49%	8.99%
Entergy Corporation	ETR	\$4.04	\$106.04	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.06%
Evergy, Inc.	EVRG	\$2.29	\$64.59	5.12%	5.18%	5.24%	5.30%	5.36%	5.43%	5.49%	9.30%
IDACORP, Inc.	IDA	\$3.00	\$103.97	4.00%	4.25%	4.50%	4.74%	4.99%	5.24%	5.49%	8.34%
NextEra Energy, Inc.	NEE	\$1.54	\$80.89	8.90%	8.33%	7.76%	7.19%	6.62%	6.06%	5.49%	8.07%
NorthWestern Corporation	NWE	\$2.48	\$60.99	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.31%
Otter Tail Corporation	OTTR	\$1.56	\$55.71	4.70%	4.83%	4.96%	5.09%	5.22%	5.36%	5.49%	8.39%
Portland General Electric Company	POR	\$1.72	\$49.44	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	9.70%
Southern Company	SO	\$2.64	\$64.07	4.90%	5.00%	5.10%	5.19%	5.29%	5.39%	5.49%	9.87%
Xcel Energy Inc.	XEL	\$1.83	\$67.39	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	8.56%
Median					5.13%	5.20%	5.27%	5.34%	5.42%	5.49%	9.02%

**Notes:**

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals 180-trading day average as of December 31, 2021

[3] Source: Exhibit PAC 304

[4] Equals  $[3] + ([9] - [3]) / 6$

[5] Equals  $[4] + ([9] - [3]) / 6$

[6] Equals  $[5] + ([9] - [3]) / 6$

[7] Equals  $[6] + ([9] - [3]) / 6$

[8] Equals  $[7] + ([9] - [3]) / 6$

[9] Source: Exhibit PAC 306

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF- MEAN GROWTH RATE  
STOCK PRICE AVERAGING CONVENTION:**

**30 DAYS**

Company		1	2	3	4	5	6	7	8	9	10
		Annualized Dividend	Stock Price	First Stage Growth Rate (Mean)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	\$2.52	\$63.13	5.56%	5.54%	5.53%	5.52%	5.51%	5.50%	5.49%	9.91%
Alliant Energy Corporation	LNT	\$1.61	\$58.59	5.90%	5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	8.57%
Ameren Corporation	AEE	\$2.20	\$86.40	7.30%	7.00%	6.70%	6.39%	6.09%	5.79%	5.49%	8.62%
American Electric Power Company, Inc.	AEP	\$3.12	\$84.96	5.90%	5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	9.64%
Avista Corporation	AVA	\$1.69	\$40.41	4.77%	4.89%	5.01%	5.13%	5.25%	5.37%	5.49%	9.90%
CMS Energy Corporation	CMS	\$1.74	\$62.53	6.21%	6.09%	5.97%	5.85%	5.73%	5.61%	5.49%	8.68%
Duke Energy Corporation	DUK	\$3.94	\$101.53	4.93%	5.03%	5.12%	5.21%	5.30%	5.39%	5.49%	9.62%
Entergy Corporation	ETR	\$4.04	\$107.27	4.50%	4.66%	4.83%	4.99%	5.16%	5.32%	5.49%	9.38%
Evergy, Inc.	EVRG	\$2.29	\$66.43	6.41%	6.25%	6.10%	5.95%	5.79%	5.64%	5.49%	9.51%
IDACORP, Inc.	IDA	\$3.00	\$109.22	4.27%	4.47%	4.67%	4.88%	5.08%	5.28%	5.49%	8.25%
NextEra Energy, Inc.	NEE	\$1.54	\$89.80	9.78%	9.07%	8.35%	7.63%	6.92%	6.20%	5.49%	7.94%
NorthWestern Corporation	NWE	\$2.48	\$55.96	3.87%	4.14%	4.41%	4.68%	4.95%	5.22%	5.49%	9.91%
Otter Tail Corporation	OTTR	\$1.56	\$68.13	7.23%	6.94%	6.65%	6.36%	6.07%	5.78%	5.49%	8.28%
Portland General Electric Company	POR	\$1.72	\$51.06	7.58%	7.23%	6.88%	6.53%	6.19%	5.84%	5.49%	9.72%
Southern Company	SO	\$2.64	\$64.96	5.70%	5.66%	5.63%	5.59%	5.56%	5.52%	5.49%	10.04%
Xcel Energy Inc.	XEL	\$1.83	\$66.39	6.43%	6.28%	6.12%	5.96%	5.80%	5.64%	5.49%	8.69%
Median					5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	9.45%

**Notes:**

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals 30-trading day average as of December 31, 2021

[3] Source: Exhibit PAC 304

[4] Equals  $[3] + ([9] - [3]) / 6$

[5] Equals  $[4] + ([9] - [3]) / 6$

[6] Equals  $[5] + ([9] - [3]) / 6$

[7] Equals  $[6] + ([9] - [3]) / 6$

[8] Equals  $[7] + ([9] - [3]) / 6$

[9] Source: Exhibit PAC 306

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF- MEAN GROWTH RATE  
STOCK PRICE AVERAGING CONVENTION:**

**90 DAYS**

Company		1	2	3	4	5	6	7	8	9	10
		Annualized Dividend	Stock Price	First Stage Growth Rate (Mean)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	\$2.52	\$62.93	5.56%	5.54%	5.53%	5.52%	5.51%	5.50%	5.49%	9.93%
Alliant Energy Corporation	LNT	\$1.61	\$57.81	5.90%	5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	8.62%
Ameren Corporation	AEE	\$2.20	\$85.14	7.30%	7.00%	6.70%	6.39%	6.09%	5.79%	5.49%	8.66%
American Electric Power Company, Inc.	AEP	\$3.12	\$84.99	5.90%	5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	9.64%
Avista Corporation	AVA	\$1.69	\$40.38	4.77%	4.89%	5.01%	5.13%	5.25%	5.37%	5.49%	9.90%
CMS Energy Corporation	CMS	\$1.74	\$61.76	6.21%	6.09%	5.97%	5.85%	5.73%	5.61%	5.49%	8.72%
Duke Energy Corporation	DUK	\$3.94	\$101.55	4.93%	5.03%	5.12%	5.21%	5.30%	5.39%	5.49%	9.62%
Energy Corporation	ETR	\$4.04	\$106.25	4.50%	4.66%	4.83%	4.99%	5.16%	5.32%	5.49%	9.42%
Evergy, Inc.	EVRG	\$2.29	\$65.27	6.41%	6.25%	6.10%	5.95%	5.79%	5.64%	5.49%	9.58%
IDACORP, Inc.	IDA	\$3.00	\$106.01	4.27%	4.47%	4.67%	4.88%	5.08%	5.28%	5.49%	8.34%
NextEra Energy, Inc.	NEE	\$1.54	\$85.45	9.78%	9.07%	8.35%	7.63%	6.92%	6.20%	5.49%	8.07%
NorthWestern Corporation	NWE	\$2.48	\$58.26	3.87%	4.14%	4.41%	4.68%	4.95%	5.22%	5.49%	9.73%
Otter Tail Corporation	OTTR	\$1.56	\$62.00	7.23%	6.94%	6.65%	6.36%	6.07%	5.78%	5.49%	8.56%
Portland General Electric Company	POR	\$1.72	\$49.88	7.58%	7.23%	6.88%	6.53%	6.19%	5.84%	5.49%	9.82%
Southern Company	SO	\$2.64	\$64.12	5.70%	5.66%	5.63%	5.59%	5.56%	5.52%	5.49%	10.10%
Xcel Energy Inc.	XEL	\$1.83	\$65.47	6.43%	6.28%	6.12%	5.96%	5.80%	5.64%	5.49%	8.74%
Median					5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	9.50%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals 90-trading day average as of December 31, 2021

[3] Source: Exhibit PAC 304

[4] Equals  $[3] + ([9] - [3]) / 6$

[5] Equals  $[4] + ([9] - [3]) / 6$

[6] Equals  $[5] + ([9] - [3]) / 6$

[7] Equals  $[6] + ([9] - [3]) / 6$

[8] Equals  $[7] + ([9] - [3]) / 6$

[9] Source: Exhibit PAC 306

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF- MEAN GROWTH RATE  
STOCK PRICE AVERAGING CONVENTION:**

**180 DAYS**

		1	2	3	4	5	6	7	8	9	10
				First Stage						Third Stage	
Company		Annualized Dividend	Stock Price	Growth Rate (Mean)	Year 6	Year 7	Year 8	Year 9	Year 10	Growth Rate	ROE
ALLETE, Inc.	ALE	\$2.52	\$66.46	5.56%	5.54%	5.53%	5.52%	5.51%	5.50%	5.49%	9.69%
Alliant Energy Corporation	LNT	\$1.61	\$57.87	5.90%	5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	8.61%
Ameren Corporation	AEE	\$2.20	\$84.84	7.30%	7.00%	6.70%	6.39%	6.09%	5.79%	5.49%	8.67%
American Electric Power Company, Inc.	AEP	\$3.12	\$85.87	5.90%	5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	9.60%
Avista Corporation	AVA	\$1.69	\$42.34	4.77%	4.89%	5.01%	5.13%	5.25%	5.37%	5.49%	9.69%
CMS Energy Corporation	CMS	\$1.74	\$62.01	6.21%	6.09%	5.97%	5.85%	5.73%	5.61%	5.49%	8.70%
Duke Energy Corporation	DUK	\$3.94	\$102.02	4.93%	5.03%	5.12%	5.21%	5.30%	5.39%	5.49%	9.60%
Entergy Corporation	ETR	\$4.04	\$106.04	4.50%	4.66%	4.83%	4.99%	5.16%	5.32%	5.49%	9.43%
Evergy, Inc.	EVERG	\$2.29	\$64.59	6.41%	6.25%	6.10%	5.95%	5.79%	5.64%	5.49%	9.63%
IDACORP, Inc.	IDA	\$3.00	\$103.97	4.27%	4.47%	4.67%	4.88%	5.08%	5.28%	5.49%	8.40%
NextEra Energy, Inc.	NEE	\$1.54	\$80.89	9.78%	9.07%	8.35%	7.63%	6.92%	6.20%	5.49%	8.22%
NorthWestern Corporation	NWE	\$2.48	\$60.99	3.87%	4.14%	4.41%	4.68%	4.95%	5.22%	5.49%	9.53%
Otter Tail Corporation	OTTR	\$1.56	\$55.71	7.23%	6.94%	6.65%	6.36%	6.07%	5.78%	5.49%	8.92%
Portland General Electric Company	POR	\$1.72	\$49.44	7.58%	7.23%	6.88%	6.53%	6.19%	5.84%	5.49%	9.86%
Southern Company	SO	\$2.64	\$64.07	5.70%	5.66%	5.63%	5.59%	5.56%	5.52%	5.49%	10.10%
Xcel Energy Inc.	XEL	\$1.83	\$67.39	6.43%	6.28%	6.12%	5.96%	5.80%	5.64%	5.49%	8.65%
Median					5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	9.48%

**Notes:**

- [1] Source: Bloomberg Professional
- [2] Source: Bloomberg Professional, equals 180-trading day average as of December 31, 2021
- [3] Source: Exhibit PAC 304
- [4] Equals  $[3] + ([9] - [3]) / 6$
- [5] Equals  $[4] + ([9] - [3]) / 6$
- [6] Equals  $[5] + ([9] - [3]) / 6$
- [7] Equals  $[6] + ([9] - [3]) / 6$
- [8] Equals  $[7] + ([9] - [3]) / 6$
- [9] Source: Exhibit PAC 306
- [10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF- HIGH GROWTH RATE  
STOCK PRICE AVERAGING CONVENTION:**

**30 DAYS**

Company		1	2	3	4	5	6	7	8	9	10
		Annualized Dividend	Stock Price	First Stage Growth Rate (high)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	\$2.52	\$63.13	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	10.04%
Alliant Energy Corporation	LNT	\$1.61	\$58.59	6.10%	6.00%	5.90%	5.79%	5.69%	5.59%	5.49%	8.61%
Ameren Corporation	AEE	\$2.20	\$86.40	7.90%	7.50%	7.10%	6.69%	6.29%	5.89%	5.49%	8.74%
American Electric Power Company, Inc.	AEP	\$3.12	\$84.96	6.50%	6.33%	6.16%	5.99%	5.82%	5.66%	5.49%	9.80%
Avista Corporation	AVA	\$1.69	\$40.41	6.20%	6.08%	5.96%	5.84%	5.72%	5.61%	5.49%	10.32%
CMS Energy Corporation	CMS	\$1.74	\$62.53	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	8.85%
Duke Energy Corporation	DUK	\$3.94	\$101.53	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	10.19%
Energy Corporation	ETR	\$4.04	\$107.27	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	9.78%
Evergy, Inc.	EVRG	\$2.29	\$66.43	8.00%	7.58%	7.16%	6.74%	6.32%	5.91%	5.49%	9.93%
IDACORP, Inc.	IDA	\$3.00	\$109.22	4.40%	4.58%	4.76%	4.94%	5.12%	5.31%	5.49%	8.27%
NextEra Energy, Inc.	NEE	\$1.54	\$89.80	10.50%	9.66%	8.83%	7.99%	7.16%	6.32%	5.49%	8.06%
NorthWestern Corporation	NWE	\$2.48	\$55.96	4.50%	4.66%	4.83%	4.99%	5.16%	5.32%	5.49%	10.09%
Otter Tail Corporation	OTTR	\$1.56	\$68.13	9.00%	8.41%	7.83%	7.24%	6.66%	6.07%	5.49%	8.62%
Portland General Electric Company	POR	\$1.72	\$51.06	8.60%	8.08%	7.56%	7.04%	6.52%	6.01%	5.49%	9.99%
Southern Company	SO	\$2.64	\$64.96	6.20%	6.08%	5.96%	5.84%	5.72%	5.61%	5.49%	10.18%
Xcel Energy Inc.	XEL	\$1.83	\$66.39	6.90%	6.66%	6.43%	6.19%	5.96%	5.72%	5.49%	8.79%
Median					6.50%	6.30%	6.09%	5.89%	5.69%	5.49%	9.79%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals 30-trading day average as of December 31, 2021

[3] Source: Exhibit PAC 304

[4] Equals  $[3] + ([9] - [3]) / 6$

[5] Equals  $[4] + ([9] - [3]) / 6$

[6] Equals  $[5] + ([9] - [3]) / 6$

[7] Equals  $[6] + ([9] - [3]) / 6$

[8] Equals  $[7] + ([9] - [3]) / 6$

[9] Source: Exhibit PAC 306

[10] Equals internal rate of return of cash flows for Year 0 through Year 200



**MULTI-STAGE DCF- HIGH GROWTH RATE  
STOCK PRICE AVERAGING CONVENTION:**

**90 DAYS**

Company		1	2	3	4	5	6	7	8	9	10
		Annualized Dividend	Stock Price	First Stage Growth Rate (high)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	\$2.52	\$62.93	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	10.05%
Alliant Energy Corporation	LNT	\$1.61	\$57.81	6.10%	6.00%	5.90%	5.79%	5.69%	5.59%	5.49%	8.66%
Ameren Corporation	AEE	\$2.20	\$85.14	7.90%	7.50%	7.10%	6.69%	6.29%	5.89%	5.49%	8.79%
American Electric Power Company, Inc.	AEP	\$3.12	\$84.99	6.50%	6.33%	6.16%	5.99%	5.82%	5.66%	5.49%	9.80%
Avista Corporation	AVA	\$1.69	\$40.38	6.20%	6.08%	5.96%	5.84%	5.72%	5.61%	5.49%	10.32%
CMS Energy Corporation	CMS	\$1.74	\$61.76	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	8.89%
Duke Energy Corporation	DUK	\$3.94	\$101.55	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	10.19%
Entergy Corporation	ETR	\$4.04	\$106.25	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	9.82%
Evergy, Inc.	EVRG	\$2.29	\$65.27	8.00%	7.58%	7.16%	6.74%	6.32%	5.91%	5.49%	10.01%
IDACORP, Inc.	IDA	\$3.00	\$106.01	4.40%	4.58%	4.76%	4.94%	5.12%	5.31%	5.49%	8.36%
NextEra Energy, Inc.	NEE	\$1.54	\$85.45	10.50%	9.66%	8.83%	7.99%	7.16%	6.32%	5.49%	8.19%
NorthWestern Corporation	NWE	\$2.48	\$58.26	4.50%	4.66%	4.83%	4.99%	5.16%	5.32%	5.49%	9.91%
Otter Tail Corporation	OTTR	\$1.56	\$62.00	9.00%	8.41%	7.83%	7.24%	6.66%	6.07%	5.49%	8.94%
Portland General Electric Company	POR	\$1.72	\$49.88	8.60%	8.08%	7.56%	7.04%	6.52%	6.01%	5.49%	10.10%
Southern Company	SO	\$2.64	\$64.12	6.20%	6.08%	5.96%	5.84%	5.72%	5.61%	5.49%	10.24%
Xcel Energy Inc.	XEL	\$1.83	\$65.47	6.90%	6.66%	6.43%	6.19%	5.96%	5.72%	5.49%	8.84%
Median					6.50%	6.30%	6.09%	5.89%	5.69%	5.49%	9.81%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals 90-trading day average as of December 31, 2021

[3] Source: Exhibit PAC 304

[4] Equals  $[3] + ([9] - [3]) / 6$

[5] Equals  $[4] + ([9] - [3]) / 6$

[6] Equals  $[5] + ([9] - [3]) / 6$

[7] Equals  $[6] + ([9] - [3]) / 6$

[8] Equals  $[7] + ([9] - [3]) / 6$

[9] Source: Exhibit PAC 306

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

**MULTI-STAGE DCF- HIGH 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 Growth Rate (high)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	\$2.52	\$66.46	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	9.81%
Alliant Energy Corporation	LNT	\$1.61	\$57.87	6.10%	6.00%	5.90%	5.79%	5.69%	5.59%	5.49%	8.65%
Ameren Corporation	AEE	\$2.20	\$84.84	7.90%	7.50%	7.10%	6.69%	6.29%	5.89%	5.49%	8.80%
American Electric Power Company, Inc.	AEP	\$3.12	\$85.87	6.50%	6.33%	6.16%	5.99%	5.82%	5.66%	5.49%	9.76%
Avista Corporation	AVA	\$1.69	\$42.34	6.20%	6.08%	5.96%	5.84%	5.72%	5.61%	5.49%	10.10%
CMS Energy Corporation	CMS	\$1.74	\$62.01	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	8.88%
Duke Energy Corporation	DUK	\$3.94	\$102.02	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	10.17%
Entergy Corporation	ETR	\$4.04	\$106.04	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	9.83%
Evergy, Inc.	EVRG	\$2.29	\$64.59	8.00%	7.58%	7.16%	6.74%	6.32%	5.91%	5.49%	10.06%
IDACORP, Inc.	IDA	\$3.00	\$103.97	4.40%	4.58%	4.76%	4.94%	5.12%	5.31%	5.49%	8.42%
NextEra Energy, Inc.	NEE	\$1.54	\$80.89	10.50%	9.66%	8.83%	7.99%	7.16%	6.32%	5.49%	8.35%
NorthWestern Corporation	NWE	\$2.48	\$60.99	4.50%	4.66%	4.83%	4.99%	5.16%	5.32%	5.49%	9.70%
Otter Tail Corporation	OTTR	\$1.56	\$55.71	9.00%	8.41%	7.83%	7.24%	6.66%	6.07%	5.49%	9.33%
Portland General Electric Company	POR	\$1.72	\$49.44	8.60%	8.08%	7.56%	7.04%	6.52%	6.01%	5.49%	10.14%
Southern Company	SO	\$2.64	\$64.07	6.20%	6.08%	5.96%	5.84%	5.72%	5.61%	5.49%	10.25%
Xcel Energy Inc.	XEL	\$1.83	\$67.39	6.90%	6.66%	6.43%	6.19%	5.96%	5.72%	5.49%	8.74%
Median					6.50%	6.30%	6.09%	5.89%	5.69%	5.49%	9.73%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, equals 180-trading day average as of December 31, 2021

[3] Source: Exhibit PAC 304

[4] Equals  $[3] + ([9] - [3]) / 6$

[5] Equals  $[4] + ([9] - [3]) / 6$

[6] Equals  $[5] + ([9] - [3]) / 6$

[7] Equals  $[6] + ([9] - [3]) / 6$

[8] Equals  $[7] + ([9] - [3]) / 6$

[9] Source: Exhibit PAC 306

[10] Equals internal rate of return of cash flows for Year 0 through Year 200

Docket No. UE 399  
Exhibit PAC/306  
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Ann E. Bulkley  
Gross Domestic Product Growth**

**March 2022**

**Long-Term Growth Rate**

<b>CALCULATION OF LONG-TERM GDP GROWTH RATE</b>			
Real GDP (\$ Billions) [1]			
	1929	\$	1,110.2
	2020	\$	18,384.7
<b>Compound Annual Growth Rate</b>			<b>3.13%</b>
Consumer Price Index (YoY % Change) [2]			
	2028-2032		2.20%
Average			2.20%
Consumer Price Index (All-Urban) [3]			
	2031		3.26
	2050		5.00
Compound Annual Growth Rate			2.27%
GDP Chain-type Price Index (2012=1.000) [3]			
	2031		1.42
	2050		2.21
Compound Annual Growth Rate			2.37%
<b>Average Inflation Forecast</b>			<b>2.28%</b>
<b>Long-Term GDP Growth Rate</b>			<b>5.49%</b>

Notes:

[1] Bureau of Economic Analysis, December 31, 2021

[2] Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021 at 14

[3] Energy Information Administration, Annual Energy Outlook 2021 at Table 20, February 3, 2021

Docket No. UE 399  
Exhibit PAC/307  
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Ann E. Bulkley  
Capital Asset Pricing Model**

**March 2022**

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m - R_f) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta ( $\beta$ )	Market Return (Rm)	Market Risk Premium (Rm - Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	1.87%	0.90	12.63%	10.76%	11.55%	11.82%
Alliant Energy Corporation	LNT	1.87%	0.85	12.63%	10.76%	11.01%	11.42%
Ameren Corporation	AEE	1.87%	0.80	12.63%	10.76%	10.47%	11.01%
American Electric Power Company, Inc.	AEP	1.87%	0.75	12.63%	10.76%	9.94%	10.61%
Avista Corporation	AVA	1.87%	0.95	12.63%	10.76%	12.09%	12.22%
CMS Energy Corporation	CMS	1.87%	0.80	12.63%	10.76%	10.47%	11.01%
Duke Energy Corporation	DUK	1.87%	0.85	12.63%	10.76%	11.01%	11.42%
Entergy Corporation	ETR	1.87%	0.95	12.63%	10.76%	12.09%	12.22%
Evergy, Inc.	EVRG	1.87%	0.95	12.63%	10.76%	12.09%	12.22%
IDACORP, Inc.	IDA	1.87%	0.80	12.63%	10.76%	10.47%	11.01%
NextEra Energy, Inc.	NEE	1.87%	0.90	12.63%	10.76%	11.55%	11.82%
NorthWestern Corporation	NWE	1.87%	0.95	12.63%	10.76%	12.09%	12.22%
Otter Tail Corporation	OTTR	1.87%	0.90	12.63%	10.76%	11.55%	11.82%
Portland General Electric Company	POR	1.87%	0.90	12.63%	10.76%	11.55%	11.82%
Southern Company	SO	1.87%	0.95	12.63%	10.76%	12.09%	12.22%
Xcel Energy Inc.	XEL	1.87%	0.80	12.63%	10.76%	10.47%	11.01%
Mean			0.88			11.28%	11.62%

Notes:

[1] Source: Bloomberg Professional, as of December 31, 2021

[2] Source: Value Line

[3] Source: PAC 307 p. 11

[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 & VL BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m - R_f) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2022 - Q2 2023)	Beta ( $\beta$ )	Market Return ( $R_m$ )	Market Risk Premium ( $R_m - R_f$ )	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	2.52%	0.90	12.63%	10.11%	11.62%	11.87%
Alliant Energy Corporation	LNT	2.52%	0.85	12.63%	10.11%	11.11%	11.49%
Ameren Corporation	AEE	2.52%	0.80	12.63%	10.11%	10.60%	11.11%
American Electric Power Company, Inc.	AEP	2.52%	0.75	12.63%	10.11%	10.10%	10.73%
Avista Corporation	AVA	2.52%	0.95	12.63%	10.11%	12.12%	12.25%
CMS Energy Corporation	CMS	2.52%	0.80	12.63%	10.11%	10.60%	11.11%
Duke Energy Corporation	DUK	2.52%	0.85	12.63%	10.11%	11.11%	11.49%
Entergy Corporation	ETR	2.52%	0.95	12.63%	10.11%	12.12%	12.25%
Evergy, Inc.	EVERG	2.52%	0.95	12.63%	10.11%	12.12%	12.25%
IDACORP, Inc.	IDA	2.52%	0.80	12.63%	10.11%	10.60%	11.11%
NextEra Energy, Inc.	NEE	2.52%	0.90	12.63%	10.11%	11.62%	11.87%
NorthWestern Corporation	NWE	2.52%	0.95	12.63%	10.11%	12.12%	12.25%
Otter Tail Corporation	OTTR	2.52%	0.90	12.63%	10.11%	11.62%	11.87%
Portland General Electric Company	POR	2.52%	0.90	12.63%	10.11%	11.62%	11.87%
Southern Company	SO	2.52%	0.95	12.63%	10.11%	12.12%	12.25%
Xcel Energy Inc.	XEL	2.52%	0.80	12.63%	10.11%	10.60%	11.11%
Mean						11.36%	11.68%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 1, January 1, 2022, at 2

[2] Source: Value Line

[3] Source: PAC 307 p. 11

[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 & VL BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m - R_f) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2023 - 2027)	Beta ( $\beta$ )	Market Return ( $R_m$ )	Market Risk Premium ( $R_m - R_f$ )	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.40%	0.90	12.63%	9.23%	11.70%	11.93%
Alliant Energy Corporation	LNT	3.40%	0.85	12.63%	9.23%	11.24%	11.59%
Ameren Corporation	AEE	3.40%	0.80	12.63%	9.23%	10.78%	11.24%
American Electric Power Company, Inc.	AEP	3.40%	0.75	12.63%	9.23%	10.32%	10.90%
Avista Corporation	AVA	3.40%	0.95	12.63%	9.23%	12.16%	12.28%
CMS Energy Corporation	CMS	3.40%	0.80	12.63%	9.23%	10.78%	11.24%
Duke Energy Corporation	DUK	3.40%	0.85	12.63%	9.23%	11.24%	11.59%
Entergy Corporation	ETR	3.40%	0.95	12.63%	9.23%	12.16%	12.28%
Evergy, Inc.	EVRG	3.40%	0.95	12.63%	9.23%	12.16%	12.28%
IDACORP, Inc.	IDA	3.40%	0.80	12.63%	9.23%	10.78%	11.24%
NextEra Energy, Inc.	NEE	3.40%	0.90	12.63%	9.23%	11.70%	11.93%
NorthWestern Corporation	NWE	3.40%	0.95	12.63%	9.23%	12.16%	12.28%
Otter Tail Corporation	OTTR	3.40%	0.90	12.63%	9.23%	11.70%	11.93%
Portland General Electric Company	POR	3.40%	0.90	12.63%	9.23%	11.70%	11.93%
Southern Company	SO	3.40%	0.95	12.63%	9.23%	12.16%	12.28%
Xcel Energy Inc.	XEL	3.40%	0.80	12.63%	9.23%	10.78%	11.24%
Mean						11.47%	11.76%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14

[2] Source: Value Line

[3] Source: PAC 307 p. 11

[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 & BLOOMBERG BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m - R_f) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta ( $\beta$ )	Market Return ( $R_m$ )	Market Risk Premium ( $R_m - R_f$ )	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	1.87%	0.85	12.63%	10.76%	11.03%	11.43%
Alliant Energy Corporation	LNT	1.87%	0.81	12.63%	10.76%	10.55%	11.07%
Ameren Corporation	AEE	1.87%	0.76	12.63%	10.76%	10.06%	10.70%
American Electric Power Company, Inc.	AEP	1.87%	0.78	12.63%	10.76%	10.29%	10.87%
Avista Corporation	AVA	1.87%	0.78	12.63%	10.76%	10.29%	10.87%
CMS Energy Corporation	CMS	1.87%	0.75	12.63%	10.76%	9.96%	10.62%
Duke Energy Corporation	DUK	1.87%	0.73	12.63%	10.76%	9.68%	10.42%
Entergy Corporation	ETR	1.87%	0.87	12.63%	10.76%	11.23%	11.58%
Evergy, Inc.	EVRG	1.87%	0.80	12.63%	10.76%	10.51%	11.04%
IDACORP, Inc.	IDA	1.87%	0.83	12.63%	10.76%	10.84%	11.29%
NextEra Energy, Inc.	NEE	1.87%	0.78	12.63%	10.76%	10.30%	10.88%
NorthWestern Corporation	NWE	1.87%	0.92	12.63%	10.76%	11.76%	11.98%
Otter Tail Corporation	OTTR	1.87%	0.89	12.63%	10.76%	11.43%	11.73%
Portland General Electric Company	POR	1.87%	0.82	12.63%	10.76%	10.68%	11.16%
Southern Company	SO	1.87%	0.79	12.63%	10.76%	10.39%	10.95%
Xcel Energy Inc.	XEL	1.87%	0.75	12.63%	10.76%	9.94%	10.61%
Mean						10.56%	11.08%

Notes:

[1] Source: Bloomberg Professional, as of December 31, 2021

[2] Source: Bloomberg Professional, based on 10-year weekly returns

[3] Source: PAC 307 p. 11

[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 & BLOOMBERG BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m - R_f) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2022 - Q2 2023)	Beta ( $\beta$ )	Market Return (Rm)	Market Risk Premium (Rm - Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	2.52%	0.85	12.63%	10.11%	11.13%	11.50%
Alliant Energy Corporation	LNT	2.52%	0.81	12.63%	10.11%	10.68%	11.16%
Ameren Corporation	AEE	2.52%	0.76	12.63%	10.11%	10.22%	10.82%
American Electric Power Company, Inc.	AEP	2.52%	0.78	12.63%	10.11%	10.43%	10.98%
Avista Corporation	AVA	2.52%	0.78	12.63%	10.11%	10.43%	10.98%
CMS Energy Corporation	CMS	2.52%	0.75	12.63%	10.11%	10.12%	10.75%
Duke Energy Corporation	DUK	2.52%	0.73	12.63%	10.11%	9.86%	10.55%
Entergy Corporation	ETR	2.52%	0.87	12.63%	10.11%	11.31%	11.64%
Evergy, Inc.	EVRG	2.52%	0.80	12.63%	10.11%	10.64%	11.14%
IDACORP, Inc.	IDA	2.52%	0.83	12.63%	10.11%	10.95%	11.37%
NextEra Energy, Inc.	NEE	2.52%	0.78	12.63%	10.11%	10.45%	10.99%
NorthWestern Corporation	NWE	2.52%	0.92	12.63%	10.11%	11.81%	12.02%
Otter Tail Corporation	OTTR	2.52%	0.89	12.63%	10.11%	11.50%	11.78%
Portland General Electric Company	POR	2.52%	0.82	12.63%	10.11%	10.80%	11.25%
Southern Company	SO	2.52%	0.79	12.63%	10.11%	10.53%	11.05%
Xcel Energy Inc.	XEL	2.52%	0.75	12.63%	10.11%	10.10%	10.73%
Mean						10.68%	11.17%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 1, January 1, 2022, at 2

[2] Source: Bloomberg Professional, based on 10-year weekly returns

[3] Source: PAC 307 p. 11

[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 & BLOOMBERG BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m - R_f) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2023 - 2027)	Beta ( $\beta$ )	Market Return ( $R_m$ )	Market Risk Premium ( $R_m - R_f$ )	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.40%	0.85	12.63%	9.23%	11.26%	11.60%
Alliant Energy Corporation	LNT	3.40%	0.81	12.63%	9.23%	10.85%	11.29%
Ameren Corporation	AEE	3.40%	0.76	12.63%	9.23%	10.43%	10.98%
American Electric Power Company, Inc.	AEP	3.40%	0.78	12.63%	9.23%	10.62%	11.12%
Avista Corporation	AVA	3.40%	0.78	12.63%	9.23%	10.62%	11.12%
CMS Energy Corporation	CMS	3.40%	0.75	12.63%	9.23%	10.34%	10.91%
Duke Energy Corporation	DUK	3.40%	0.73	12.63%	9.23%	10.10%	10.73%
Entergy Corporation	ETR	3.40%	0.87	12.63%	9.23%	11.43%	11.73%
Evergy, Inc.	EVERG	3.40%	0.80	12.63%	9.23%	10.82%	11.27%
IDACORP, Inc.	IDA	3.40%	0.83	12.63%	9.23%	11.09%	11.48%
NextEra Energy, Inc.	NEE	3.40%	0.78	12.63%	9.23%	10.64%	11.13%
NorthWestern Corporation	NWE	3.40%	0.92	12.63%	9.23%	11.88%	12.07%
Otter Tail Corporation	OTTR	3.40%	0.89	12.63%	9.23%	11.60%	11.86%
Portland General Electric Company	POR	3.40%	0.82	12.63%	9.23%	10.96%	11.37%
Southern Company	SO	3.40%	0.79	12.63%	9.23%	10.71%	11.19%
Xcel Energy Inc.	XEL	3.40%	0.75	12.63%	9.23%	10.32%	10.90%
Mean						10.85%	11.30%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14

[2] Source: Bloomberg Professional, based on 10-year weekly returns

[3] Source: PAC 307 p. 11

[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 & VALUE LINE LT AVERAGE BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m - R_f) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta ( $\beta$ )	Market Return ( $R_m$ )	Market Risk Premium ( $R_m - R_f$ )	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	1.87%	0.76	12.63%	10.76%	10.03%	10.68%
Alliant Energy Corporation	LNT	1.87%	0.74	12.63%	10.76%	9.79%	10.50%
Ameren Corporation	AEE	1.87%	0.73	12.63%	10.76%	9.69%	10.43%
American Electric Power Company, Inc.	AEP	1.87%	0.67	12.63%	10.76%	9.06%	9.95%
Avista Corporation	AVA	1.87%	0.75	12.63%	10.76%	9.94%	10.61%
CMS Energy Corporation	CMS	1.87%	0.69	12.63%	10.76%	9.30%	10.13%
Duke Energy Corporation	DUK	1.87%	0.64	12.63%	10.76%	8.76%	9.73%
Entergy Corporation	ETR	1.87%	0.72	12.63%	10.76%	9.59%	10.35%
Evergy, Inc.	EVRG	1.87%	0.98	12.63%	10.76%	12.36%	12.42%
IDACORP, Inc.	IDA	1.87%	0.72	12.63%	10.76%	9.59%	10.35%
NextEra Energy, Inc.	NEE	1.87%	0.71	12.63%	10.76%	9.50%	10.28%
NorthWestern Corporation	NWE	1.87%	0.72	12.63%	10.76%	9.64%	10.39%
Otter Tail Corporation	OTTR	1.87%	0.86	12.63%	10.76%	11.11%	11.49%
Portland General Electric Company	POR	1.87%	0.75	12.63%	10.76%	9.89%	10.57%
Southern Company	SO	1.87%	0.61	12.63%	10.76%	8.47%	9.51%
Xcel Energy Inc.	XEL	1.87%	0.65	12.63%	10.76%	8.86%	9.80%
Mean						9.72%	10.45%

Notes:

[1] Source: Bloomberg Professional, as of December 31, 2021

[2] Source: PAC 307 p. 10

[3] Source: PAC 307 p. 11

[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 & VALUE LINE LT AVERAGE BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m - R_f) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2022 - Q2 2023)	Beta ( $\beta$ )	Market Return ( $R_m$ )	Market Risk Premium ( $R_m - R_f$ )	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	2.52%	0.76	12.63%	10.11%	10.19%	10.80%
Alliant Energy Corporation	LNT	2.52%	0.74	12.63%	10.11%	9.96%	10.63%
Ameren Corporation	AEE	2.52%	0.73	12.63%	10.11%	9.87%	10.56%
American Electric Power Company, Inc.	AEP	2.52%	0.67	12.63%	10.11%	9.27%	10.11%
Avista Corporation	AVA	2.52%	0.75	12.63%	10.11%	10.10%	10.73%
CMS Energy Corporation	CMS	2.52%	0.69	12.63%	10.11%	9.50%	10.28%
Duke Energy Corporation	DUK	2.52%	0.64	12.63%	10.11%	9.00%	9.90%
Entergy Corporation	ETR	2.52%	0.72	12.63%	10.11%	9.78%	10.49%
Evergy, Inc.	EVERG	2.52%	0.98	12.63%	10.11%	12.37%	12.44%
IDACORP, Inc.	IDA	2.52%	0.72	12.63%	10.11%	9.78%	10.49%
NextEra Energy, Inc.	NEE	2.52%	0.71	12.63%	10.11%	9.69%	10.42%
NorthWestern Corporation	NWE	2.52%	0.72	12.63%	10.11%	9.82%	10.52%
Otter Tail Corporation	OTTR	2.52%	0.86	12.63%	10.11%	11.20%	11.56%
Portland General Electric Company	POR	2.52%	0.75	12.63%	10.11%	10.05%	10.70%
Southern Company	SO	2.52%	0.61	12.63%	10.11%	8.72%	9.70%
Xcel Energy Inc.	XEL	2.52%	0.65	12.63%	10.11%	9.09%	9.97%
Mean						9.90%	10.58%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 1, January 1, 2022, at 2

[2] Source: PAC 307 p. 10

[3] Source: PAC 307 p. 11

[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 & VALUE LINE LT BETA

$$K = R_f + \beta (R_m - R_f)$$

$$K = R_f + 0.25 \times (R_m - R_f) + 0.75 \times \beta \times (R_m - R_f)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2023 - 2027)	Beta ( $\beta$ )	Market Return ( $R_m$ )	Market Risk Premium ( $R_m - R_f$ )	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.40%	0.76	12.63%	9.23%	10.40%	10.96%
Alliant Energy Corporation	LNT	3.40%	0.74	12.63%	9.23%	10.19%	10.80%
Ameren Corporation	AEE	3.40%	0.73	12.63%	9.23%	10.11%	10.74%
American Electric Power Company, Inc.	AEP	3.40%	0.67	12.63%	9.23%	9.56%	10.33%
Avista Corporation	AVA	3.40%	0.75	12.63%	9.23%	10.32%	10.90%
CMS Energy Corporation	CMS	3.40%	0.69	12.63%	9.23%	9.77%	10.49%
Duke Energy Corporation	DUK	3.40%	0.64	12.63%	9.23%	9.31%	10.14%
Entergy Corporation	ETR	3.40%	0.72	12.63%	9.23%	10.03%	10.68%
Evergy, Inc.	EVRG	3.40%	0.98	12.63%	9.23%	12.40%	12.45%
IDACORP, Inc.	IDA	3.40%	0.72	12.63%	9.23%	10.03%	10.68%
NextEra Energy, Inc.	NEE	3.40%	0.71	12.63%	9.23%	9.94%	10.61%
NorthWestern Corporation	NWE	3.40%	0.72	12.63%	9.23%	10.07%	10.71%
Otter Tail Corporation	OTTR	3.40%	0.86	12.63%	9.23%	11.33%	11.65%
Portland General Electric Company	POR	3.40%	0.75	12.63%	9.23%	10.28%	10.86%
Southern Company	SO	3.40%	0.61	12.63%	9.23%	9.06%	9.95%
Xcel Energy Inc.	XEL	3.40%	0.65	12.63%	9.23%	9.40%	10.20%
Mean						10.14%	10.76%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14

[2] Source: PAC 307 p. 10

[3] Source: PAC 307 p. 11

[4] Equals [3] - [1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL BETA - 2011 - 2020

Company	Ticker	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
		12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	Average
ALLETE, Inc.	ALE	0.70	0.70	0.75	0.80	0.80	0.75	0.80	0.65	0.65	0.85	0.90	0.76
Alliant Energy Corporation	LNT	0.75	0.70	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.74
Ameren Corporation	AEE	0.80	0.80	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.73
American Electric Power Company, Inc.	AEP	0.70	0.65	0.70	0.70	0.70	0.65	0.65	0.55	0.55	0.75	0.75	0.67
Avista Corporation	AVA	0.70	0.70	0.70	0.80	0.80	0.70	0.75	0.65	0.60	0.90	0.95	0.75
CMS Energy Corporation	CMS	0.75	0.75	0.70	0.70	0.75	0.65	0.65	0.55	0.50	0.80	0.80	0.69
Duke Energy Corporation	DUK	0.65	0.60	0.65	0.60	0.65	0.60	0.60	0.50	0.50	0.85	0.85	0.64
Entergy Corporation	ETR	0.70	0.70	0.70	0.70	0.70	0.65	0.65	0.60	0.60	0.95	0.95	0.72
Evergy, Inc.	EVRG								NMF	NMF	1.00	0.95	0.98
IDACORP, Inc.	IDA	0.70	0.70	0.70	0.80	0.80	0.75	0.70	0.60	0.55	0.80	0.80	0.72
NextEra Energy, Inc.	NEE	0.75	0.70	0.70	0.70	0.75	0.65	0.65	0.55	0.55	0.90	0.90	0.71
NorthWestern Corporation	NWE	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.60	0.60	0.90	0.95	0.72
Otter Tail Corporation	OTTR	0.90	0.90	0.95	0.90	0.85	0.85	0.90	0.75	0.70	0.85	0.90	0.86
Portland General Electric Company	POR	0.75	0.75	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.90	0.75
Southern Company	SO	0.55	0.55	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.61
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.70	0.65	0.60	0.60	0.55	0.50	0.80	0.80	0.65
Mean		0.72	0.70	0.72	0.73	0.74	0.68	0.69	0.59	0.57	0.86	0.88	0.73

Notes:

- [1] Value Line, dated November 4, 2011, November 25, 2011, and December 23, 2011.
- [2] Value Line, dated November 2, 2012, November 23, 2012, and December 21, 2012.
- [3] Value Line, dated November 1, 2013, November 22, 2013, and December 20, 2013.
- [4] Value Line, dated October 31, 2014, November 21, 2014, and December 19, 2014.
- [5] Value Line, dated October 30, 2015, November 20, 2015, and December 18, 2015.
- [6] Value Line, dated October 28, 2016, November 18, 2016, and December 16, 2016.
- [7] Value Line, dated October 27, 2017, November 17, 2017, and December 15, 2017.
- [8] Value Line, dated October 18, 2018, November 16, 2018, and December 14, 2018.
- [9] Value Line, dated October 25, 2019, November 15, 2019, and December 13, 2019.
- [10] Value Line, dated October 23, 2020, November 13, 2020, and December 11, 2020.
- [11] Value Line, dated September 10, 2021, October 22, 2021, November 12, 2021, and December 10, 2021.
- [12] Average ([1] - [11])

MARKET RISK PREMIUM DERIVED FROM ANALYSTS' LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield	1.48%
[2] Estimated Weighted Average Long-Term Growth Rate	11.06%
[3] S&P 500 Estimated Required Market Return	12.63%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outstg	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	332.78	92.23	30,692.67	0.10%	4.90%	0.00%	8.00%	0.01%
Signature Bank/New York NY	SBNY	60.47	323.47	19,559.91	0.06%	0.69%	0.00%	12.00%	0.01%
American Express Co	AXP	774.56	163.60	126,717.36	0.39%	1.05%	0.00%	8.50%	0.03%
Verizon Communications Inc	VZ	4,197.76	51.96	218,115.61	0.68%	4.93%	0.03%	2.50%	0.02%
Broadcom Inc	AVGO	412.87	665.41	274,730.49		2.46%		27.00%	
Boeing Co/The	BA	587.70	201.32	118,315.56		n/a			
Caterpillar Inc	CAT	540.94	206.74	111,834.35	0.35%	2.15%	0.01%	9.50%	0.03%
JPMorgan Chase & Co	JPM	2,955.27	158.35	467,966.37	1.46%	2.53%	0.04%	7.50%	0.11%
Chevron Corp	CVX	1,927.69	117.35	226,213.95		4.57%		24.00%	
Coca-Cola Co/The	KO	4,319.42	59.21	255,752.86	0.80%	2.84%	0.02%	7.00%	0.06%
AbbVie Inc	ABBV	1,767.88	135.40	239,370.95	0.74%	4.17%	0.03%	6.50%	0.05%
Walt Disney Co/The	DIS	1,817.66	154.89	281,536.74	0.88%	n/a		14.00%	0.12%
FleetCor Technologies Inc	FLT	81.20	223.84	18,175.58	0.06%	n/a		11.00%	0.01%
Extra Space Storage Inc	EXR	133.89	226.73	30,357.33	0.09%	2.21%	0.00%	5.50%	0.01%
Exxon Mobil Corp	XOM	4,233.57	61.19	259,051.96		5.75%		31.00%	
Phillips 66	PSX	438.17	72.46	31,749.80	0.10%	5.08%	0.01%	20.00%	0.02%
General Electric Co	GE	1,098.14	94.47	103,741.00	0.32%	0.34%	0.00%	15.00%	0.05%
HP Inc	HPQ	1,082.72	37.67	40,786.18	0.13%	2.65%	0.00%	15.50%	0.02%
Home Depot Inc/The	HD	1,044.24	415.01	433,369.63	1.35%	1.59%	0.02%	11.00%	0.15%
Monolithic Power Systems Inc	MPWR	46.09	493.33	22,739.06		0.49%		20.50%	
International Business Machines Corp	IBM	896.80	133.66	119,866.29	0.37%	4.91%	0.02%	0.50%	0.00%
Johnson & Johnson	JNJ	2,632.60	171.07	450,358.37	1.40%	2.48%	0.03%	10.00%	0.14%
McDonald's Corp	MCD	747.25	268.07	200,313.97	0.62%	2.06%	0.01%	10.50%	0.07%
Merck & Co Inc	MRK	2,525.94	76.64	193,588.35	0.60%	3.60%	0.02%	7.50%	0.05%
3M Co	MMM	576.25	177.63	102,359.82	0.32%	3.33%	0.01%	6.00%	0.02%
American Water Works Co Inc	AWK	181.54	188.86	34,285.27	0.11%	1.28%	0.00%	8.50%	0.01%
Bank of America Corp	BAC	8,184.08	44.49	364,109.90	1.13%	1.89%	0.02%	7.50%	0.08%
Pfizer Inc	PFE	5,612.87	59.05	331,439.80	1.03%	2.71%	0.03%	11.50%	0.12%
Procter & Gamble Co/The	PG	2,419.95	163.58	395,855.09	1.23%	2.13%	0.03%	7.00%	0.09%
AT&T Inc	T	7,141.00	24.60	175,668.60	0.55%	8.46%	0.05%	1.50%	0.01%
Travelers Cos Inc/The	TRV	246.01	156.43	38,483.19	0.12%	2.25%	0.00%	8.00%	0.01%
Raytheon Technologies Corp	RTX	1,496.78	86.06	128,812.71	0.40%	2.37%	0.01%	1.50%	0.01%
Analog Devices Inc	ADI	525.33	175.77	92,337.43	0.29%	1.57%	0.00%	11.00%	0.03%
Walmart Inc	WMT	2,773.88	144.69	401,352.41	1.25%	1.52%	0.02%	7.50%	0.09%
Cisco Systems Inc/Delaware	CSCO	4,217.61	63.37	267,269.76	0.83%	2.34%	0.02%	7.00%	0.06%
Intel Corp	INTC	4,067.00	51.50	209,450.50	0.65%	2.70%	0.02%	7.00%	0.05%
General Motors Co	GM	1,451.86	58.63	85,122.55	0.26%	n/a		12.00%	0.03%
Microsoft Corp	MSFT	7,507.98	336.32	2,525,083.83	7.85%	0.74%	0.06%	15.00%	1.18%
Dollar General Corp	DG	231.71	235.83	54,643.46	0.17%	0.71%	0.00%	10.50%	0.02%
Cigna Corp	CI	331.43	229.63	76,105.81	0.24%	1.74%	0.00%	10.00%	0.02%
Kinder Morgan Inc	KMI	2,267.43	15.86	35,961.38	0.11%	6.81%	0.01%	19.00%	0.02%
Citigroup Inc	C	1,984.27	60.39	119,829.88	0.37%	3.38%	0.01%	7.00%	0.03%
American International Group Inc	AIG	830.30	56.86	47,210.74		2.25%		31.50%	
Altria Group Inc	MO	1,836.99	47.39	87,054.91	0.27%	7.60%	0.02%	6.00%	0.02%
HCA Healthcare Inc	HCA	311.02	256.92	79,908.03	0.25%	0.75%	0.00%	13.50%	0.03%
Under Armour Inc	UA	188.65	21.19	3,997.41		n/a		33.00%	
International Paper Co	IP	387.26	46.98	18,193.62	0.06%	3.94%	0.00%	12.00%	0.01%
Hewlett Packard Enterprise Co	HPE	1,293.44	15.77	20,397.55	0.06%	3.04%	0.00%	6.50%	0.00%
Abbott Laboratories	ABT	1,768.29	140.74	248,868.71	0.77%	1.34%	0.01%	11.50%	0.09%
Aflac Inc	AFL	661.53	58.39	38,626.62	0.12%	2.74%	0.00%	11.00%	0.01%
Air Products and Chemicals Inc	APD	221.68	304.26	67,449.57	0.21%	1.97%	0.00%	12.50%	0.03%
Royal Caribbean Cruises Ltd	RCL	254.79	76.90	19,593.35		n/a			
Hess Corp	HES	309.73	74.03	22,929.09		1.35%			
Archer-Daniels-Midland Co	ADM	559.44	67.59	37,812.62	0.12%	2.19%	0.00%	9.50%	0.01%
Automatic Data Processing Inc	ADP	421.38	246.58	103,904.87	0.32%	1.69%	0.01%	8.50%	0.03%
Verisk Analytics Inc	VRSK	161.16	228.73	36,862.36	0.11%	0.51%	0.00%	11.50%	0.01%
AutoZone Inc	AZO	20.63	2,096.39	43,256.91	0.13%	n/a		15.00%	0.02%
Avery Dennison Corp	AVY	82.80	216.57	17,931.13	0.06%	1.26%	0.00%	9.00%	0.01%
Enphase Energy Inc	ENPH	134.91	182.94	24,680.80		n/a		40.00%	
MSCI Inc	MSCI	82.45	612.69	50,514.45	0.16%	0.68%	0.00%	16.00%	0.03%
Ball Corp	BLL	323.89	96.27	31,181.28		0.83%		21.00%	
Ceridian HCM Holding Inc	CDAY	151.33	104.46	15,808.04		n/a			
Carrier Global Corp	CARR	866.59	54.24	47,003.57		1.11%			
Bank of New York Mellon Corp/The	BK	825.82	58.08	47,963.68	0.15%	2.34%	0.00%	5.00%	0.01%
Otis Worldwide Corp	OTIS	424.77	87.07	36,984.64		1.10%			
Baxter International Inc	BAX	500.69	85.84	42,979.49	0.13%	1.30%	0.00%	8.50%	0.01%
Becton Dickinson and Co	BDX	285.04	251.48	71,682.61	0.22%	1.38%	0.00%	7.50%	0.02%
Berkshire Hathaway Inc	BRK/B	1,303.48	299.00	389,739.62	1.21%	n/a		6.00%	0.07%
Best Buy Co Inc	BBY	240.56	101.60	24,441.00	0.08%	2.76%	0.00%	8.50%	0.01%
Boston Scientific Corp	BSX	1,424.99	42.48	60,533.66	0.19%	n/a		17.50%	0.03%
Bristol-Myers Squibb Co	BMJ	2,219.65	62.35	138,394.87	0.43%	3.46%	0.01%	12.50%	0.05%
Fortune Brands Home & Security Inc	FBHS	135.73	106.90	14,509.96	0.05%	1.05%	0.00%	11.00%	0.00%
Brown-Forman Corp	BF/B	309.74	72.86	22,567.87	0.07%	1.03%	0.00%	13.00%	0.01%
Coterra Energy Inc	CTRA	813.58	19.00	15,457.98		2.63%			
Campbell Soup Co	CPB	301.74	43.46	13,113.53	0.04%	3.41%	0.00%	5.50%	0.00%
Hilton Worldwide Holdings Inc	HLT	278.72	155.99	43,477.84		n/a			
Carnival Corp	CCL	981.05	20.12	19,738.69		n/a			
Qorvo Inc	QRVO	110.22	156.39	17,237.77		n/a		27.00%	
Lumen Technologies Inc	LUMN	1,023.89	12.55	12,849.87	0.04%	7.97%	0.00%	3.50%	0.00%



STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outstg	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
UDR Inc	UDR	309.19	59.99	18,548.07	0.06%	2.42%	0.00%	6.00%	0.00%
Clorox Co/The	CLX	122.86	174.36	21,422.39	0.07%	2.66%	0.00%	5.00%	0.00%
Paycom Software Inc	PAYC	60.03	415.19	24,922.19	0.08%	n/a		19.50%	0.02%
CMS Energy Corp	CMS	289.70	65.05	18,844.79	0.06%	2.67%	0.00%	6.00%	0.00%
Newell Brands Inc	NWL	425.40	21.84	9,290.74		4.21%			
Colgate-Palmolive Co	CL	842.85	85.34	71,928.73	0.22%	2.11%	0.00%	5.00%	0.01%
EPAM Systems Inc	EPAM	56.72	668.45	37,914.48		n/a		23.50%	
Comerica Inc	CMA	131.15	87.00	11,409.96	0.04%	3.13%	0.00%	2.50%	0.00%
IPG Photonics Corp	IPGP	53.31	172.14	9,176.61	0.03%	n/a		17.00%	0.00%
Conagra Brands Inc	CAG	479.69	34.15	16,381.41	0.05%	3.66%	0.00%	4.50%	0.00%
Consolidated Edison Inc	ED	353.75	85.32	30,181.86	0.09%	3.63%	0.00%	3.00%	0.00%
Corning Inc	GLW	853.41	37.23	31,772.38	0.10%	2.58%	0.00%	20.00%	0.02%
Cummins Inc	CMI	143.03	218.14	31,201.00	0.10%	2.66%	0.00%	7.00%	0.01%
Caesars Entertainment Inc	CZR	213.77	93.53	19,994.28		n/a			
Danaher Corp	DHR	714.58	329.01	235,102.98		0.26%		21.00%	
Target Corp	TGT	479.12	231.44	110,888.46	0.34%	1.56%	0.01%	15.00%	0.05%
Deere & Co	DE	307.41	342.89	105,406.79		1.22%		21.50%	
Dominion Energy Inc	D	810.00	78.56	63,633.60	0.20%	3.21%	0.01%	12.00%	0.02%
Dover Corp	DOV	143.99	181.60	26,147.68	0.08%	1.10%	0.00%	9.00%	0.01%
Alliant Energy Corp	LNT	250.36	61.47	15,389.69	0.05%	2.62%	0.00%	5.50%	0.00%
Duke Energy Corp	DUK	769.00	104.90	80,668.10	0.25%	3.76%	0.01%	7.00%	0.02%
Regency Centers Corp	REG	171.21	75.35	12,900.90	0.04%	3.32%	0.00%	16.00%	0.01%
Eaton Corp PLC	ETN	398.60	172.82	68,886.05	0.21%	1.76%	0.00%	11.50%	0.02%
Ecolab Inc	ECL	286.57	234.59	67,225.75	0.21%	0.87%	0.00%	6.00%	0.01%
PerkinElmer Inc	PKI	126.20	201.06	25,373.77	0.08%	0.14%	0.00%	12.00%	0.01%
Emerson Electric Co	EMR	595.70	92.97	55,382.14	0.17%	2.22%	0.00%	11.50%	0.02%
EOG Resources Inc	EOG	585.09	88.83	51,973.54	0.16%	3.38%	0.01%	16.00%	0.03%
Aon PLC	AON	220.33	300.56	66,222.99	0.21%	0.68%	0.00%	7.00%	0.01%
Entergy Corp	ETR	200.98	112.65	22,640.51	0.07%	3.59%	0.00%	3.00%	0.00%
Equifax Inc	EFX	122.00	292.79	35,720.97	0.11%	0.53%	0.00%	11.00%	0.01%
IQVIA Holdings Inc	IQV	191.04	282.14	53,900.03	0.17%	n/a		15.50%	0.03%
Gartner Inc	IT	82.24	334.32	27,494.14		n/a		20.50%	
FedEx Corp	FDX	264.97	258.64	68,531.58	0.21%	1.16%	0.00%	13.00%	0.03%
FMC Corp	FMC	126.75	109.89	13,928.67	0.04%	1.93%	0.00%	10.50%	0.00%
Brown & Brown Inc	BRO	282.43	70.28	19,848.97	0.06%	0.58%	0.00%	9.50%	0.01%
Ford Motor Co	F	3,925.39	20.77	81,530.33		1.93%		47.50%	
NextEra Energy Inc	NEE	1,962.14	93.36	183,185.11	0.57%	1.65%	0.01%	10.50%	0.06%
Franklin Resources Inc	BEN	501.80	33.49	16,805.11	0.05%	3.46%	0.00%	8.50%	0.00%
Garmin Ltd	GRMN	192.32	136.17	26,188.49	0.08%	1.97%	0.00%	10.00%	0.01%
Freepoint-McMoRan Inc	FCX	1,468.47	41.73	61,279.42		0.72%		37.50%	
Gap Inc/The	GPS	373.40	17.65	6,590.56		2.72%		27.00%	
Dexcom Inc	DXCM	96.92	536.95	52,042.27		n/a		38.50%	
General Dynamics Corp	GD	279.22	208.47	58,209.62	0.18%	2.28%	0.00%	6.00%	0.01%
General Mills Inc	GIS	603.21	67.38	40,644.09	0.13%	3.03%	0.00%	3.50%	0.00%
Genuine Parts Co	GPC	142.42	140.20	19,967.56	0.06%	2.33%	0.00%	7.00%	0.00%
Atmos Energy Corp	ATO	132.71	104.77	13,903.50	0.04%	2.60%	0.00%	7.00%	0.00%
WW Grainger Inc	GWV	51.52	518.24	26,699.72	0.08%	1.25%	0.00%	6.50%	0.01%
Halliburton Co	HAL	895.12	22.87	20,471.30	0.06%	0.79%	0.00%	9.00%	0.01%
L3Harris Technologies Inc	LHX	196.23	213.24	41,843.02		1.91%			
Healthpeak Properties Inc	PEAK	539.07	36.09	19,455.11		3.33%		-12.00%	
Catalent Inc	CTLT	171.19	128.03	21,917.20		n/a		21.00%	
Fortive Corp	FTV	358.58	76.29	27,355.92	0.09%	0.37%	0.00%	6.00%	0.01%
Hershey Co/The	HSY	145.39	193.47	28,128.60	0.09%	1.86%	0.00%	6.00%	0.01%
Synchrony Financial	SYF	547.26	46.39	25,387.35	0.08%	1.90%	0.00%	9.50%	0.01%
Hormel Foods Corp	HRL	542.57	48.81	26,482.84	0.08%	2.13%	0.00%	9.00%	0.01%
Arthur J Gallagher & Co	AJG	207.28	169.67	35,168.86	0.11%	1.13%	0.00%	13.50%	0.01%
Mondelez International Inc	MDLZ	1,394.97	66.31	92,500.59	0.29%	2.11%	0.01%	8.00%	0.02%
CenterPoint Energy Inc	CNP	628.87	27.91	17,551.65	0.05%	2.44%	0.00%	4.50%	0.00%
Humana Inc	HUM	128.53	463.86	59,621.78	0.19%	0.60%	0.00%	12.00%	0.02%
Willis Towers Watson PLC	WLTW	124.61	237.49	29,592.68	0.09%	1.35%	0.00%	8.00%	0.01%
Illinois Tool Works Inc	ITW	313.88	246.80	77,465.83	0.24%	1.98%	0.00%	10.50%	0.03%
CDW Corp/DE	CDW	135.72	204.78	27,793.36	0.09%	0.98%	0.00%	10.00%	0.01%
Trane Technologies PLC	TT	237.54	202.03	47,990.21		1.17%			
Interpublic Group of Cos Inc/The	IPG	393.76	37.45	14,746.12	0.05%	2.88%	0.00%	12.00%	0.01%
International Flavors & Fragrances Inc	IFF	254.55	150.65	38,347.51	0.12%	2.10%	0.00%	7.50%	0.01%
Jacobs Engineering Group Inc	J	129.45	139.23	18,023.74	0.06%	0.60%	0.00%	15.00%	0.01%
Generac Holdings Inc	GNRC	63.09	351.92	22,202.63		n/a		23.50%	
NXP Semiconductors NV	NXPI	265.93	227.78	60,574.22	0.19%	0.99%	0.00%	11.00%	0.02%
Kellogg Co	K	341.12	64.42	21,975.14	0.07%	3.60%	0.00%	3.50%	0.00%
Broadridge Financial Solutions Inc	BR	116.58	182.82	21,312.79	0.07%	1.40%	0.00%	9.50%	0.01%
Kimberly-Clark Corp	KMB	336.72	142.92	48,123.59	0.15%	3.19%	0.00%	4.50%	0.01%
Kimco Realty Corp	KIM	616.43	24.65	15,194.95	0.05%	2.76%	0.00%	10.50%	0.00%
Oracle Corp	ORCL	2,670.45	87.21	232,889.68	0.72%	1.47%	0.01%	10.00%	0.07%
Kroger Co/The	KR	735.26	45.26	33,277.69	0.10%	1.86%	0.00%	6.00%	0.01%
Lennar Corp	LEN	271.85	116.16	31,578.33	0.10%	0.86%	0.00%	12.50%	0.01%
Eli Lilly & Co	LLY	956.59	276.22	264,229.84	0.82%	1.42%	0.01%	12.00%	0.10%
Bath & Body Works Inc	BBWI	257.72	69.79	17,986.49		0.86%		26.00%	
Charter Communications Inc	CHTR	179.29	651.97	116,892.35		n/a		29.50%	
Lincoln National Corp	LNC	180.71	68.26	12,335.20	0.04%	2.64%	0.00%	9.00%	0.00%
Loews Corp	L	253.68	57.76	14,652.79	0.05%	0.43%	0.00%	12.50%	0.01%
Lowe's Cos Inc	LOW	673.75	258.48	174,150.12	0.54%	1.24%	0.01%	16.50%	0.09%
IDEX Corp	IEX	76.03	236.32	17,967.65	0.06%	0.91%	0.00%	8.00%	0.00%
Marsh & McLennan Cos Inc	MMC	504.90	173.82	87,760.85	0.27%	1.23%	0.00%	12.00%	0.03%
Masco Corp	MAS	244.09	70.22	17,139.79	0.05%	1.34%	0.00%	10.00%	0.01%
S&P Global Inc	SPGI	241.00	471.93	113,735.13	0.35%	0.65%	0.00%	10.50%	0.04%
Medtronic PLC	MDT	1,344.56	103.45	139,094.53	0.43%	2.44%	0.01%	9.00%	0.04%
Viatis Inc	VTRS	1,209.39	13.53	16,363.09		3.25%			
CVS Health Corp	CVS	1,320.06	103.16	136,177.29	0.42%	2.13%	0.01%	6.00%	0.03%
DuPont de Nemours Inc	DD	518.10	80.78	41,852.44		1.49%			
Micron Technology Inc	MU	1,120.17	93.15	104,343.84		0.43%		22.50%	

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outstg	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Motorola Solutions Inc	MSI	168.90	271.70	45,889.31	0.14%	1.16%	0.00%	7.00%	0.01%
Cboe Global Markets Inc	CBOE	106.64	130.40	13,906.25	0.04%	1.47%	0.00%	12.00%	0.01%
Laboratory Corp of America Holdings	LH	95.70	314.21	30,069.90	0.09%	n/a		6.00%	0.01%
Newmont Corp	NEM	797.44	62.02	49,456.92	0.15%	3.55%	0.01%	12.00%	0.02%
NIKE Inc	NKE	1,277.81	166.67	212,971.93		0.73%		27.00%	
NiSource Inc	NI	392.71	27.61	10,842.59	0.03%	3.19%	0.00%	8.50%	0.00%
Norfolk Southern Corp	NSC	243.35	297.71	72,446.24	0.23%	1.46%	0.00%	10.50%	0.02%
Principal Financial Group Inc	PFGE	265.07	72.33	19,172.44	0.06%	3.54%	0.00%	6.00%	0.00%
Eversource Energy	ES	344.27	90.98	31,321.59	0.10%	2.65%	0.00%	6.50%	0.01%
Northrop Grumman Corp	NOC	158.54	387.07	61,365.30	0.19%	1.62%	0.00%	8.50%	0.02%
Wells Fargo & Co	WFC	3,987.23	47.98	191,307.44	0.59%	1.67%	0.01%	5.50%	0.03%
Nucor Corp	NUE	285.80	114.15	32,623.96	0.10%	1.75%	0.00%	12.00%	0.01%
PVH Corp	PVH	69.98	106.65	7,463.15	0.02%	0.14%	0.00%	13.50%	0.00%
Occidental Petroleum Corp	OXY	933.98	28.99	27,076.11		0.14%		36.50%	
Omnicom Group Inc	OMC	212.56	73.27	15,574.20	0.05%	3.82%	0.00%	6.00%	0.00%
ONEOK Inc	OKE	445.94	58.76	26,203.26	0.08%	6.36%	0.01%	10.00%	0.01%
Raymond James Financial Inc	RJF	239.16	100.40	24,011.66	0.07%	1.35%	0.00%	10.50%	0.01%
Parker-Hannifin Corp	PH	128.52	318.12	40,883.19	0.13%	1.30%	0.00%	13.50%	0.02%
Rollins Inc	ROL	492.05	34.21	16,833.00	0.05%	1.17%	0.00%	11.50%	0.01%
PPL Corp	PPL	750.72	30.06	22,566.52		5.52%		-6.00%	
ConocoPhillips	COP	1,318.95	72.18	95,201.59	0.30%	1.11%	0.00%	13.50%	0.04%
PulteGroup Inc	PHM	253.19	57.16	14,472.11	0.05%	1.05%	0.00%	13.00%	0.01%
Pinnacle West Capital Corp	PNW	112.82	70.59	7,963.89		4.82%		0.00%	
PNC Financial Services Group Inc/The	PNC	422.64	200.52	84,747.97	0.26%	2.49%	0.01%	11.50%	0.03%
PPG Industries Inc	PPG	237.40	172.44	40,937.43	0.13%	1.37%	0.00%	3.00%	0.00%
Progressive Corp/The	PGR	584.40	102.65	59,988.66	0.19%	0.39%	0.00%	5.00%	0.01%
Public Service Enterprise Group Inc	PEG	505.66	66.73	33,742.96	0.10%	3.06%	0.00%	3.50%	0.00%
Robert Half International Inc	RHI	111.33	111.52	12,415.52	0.04%	1.36%	0.00%	7.50%	0.00%
Edison International	EIX	379.91	68.25	25,928.72		4.10%			
Schlumberger NV	SLB	1,402.63	29.95	42,008.86	0.13%	1.67%	0.00%	8.50%	0.01%
Charles Schwab Corp/The	SCHW	1,811.31	84.10	152,330.83	0.47%	0.86%	0.00%	7.00%	0.03%
Sherwin-Williams Co/The	SHW	262.20	352.16	92,334.94	0.29%	0.62%	0.00%	10.50%	0.03%
West Pharmaceutical Services Inc	WST	74.08	469.01	34,744.26	0.11%	0.15%	0.00%	17.00%	0.02%
J M Smucker Co/The	SJM	108.36	135.82	14,717.86	0.05%	2.92%	0.00%	4.00%	0.00%
Snap-on Inc	SNA	53.54	215.38	11,530.37	0.04%	2.64%	0.00%	4.50%	0.00%
AMETEK Inc	AME	231.33	147.04	34,014.03	0.11%	0.54%	0.00%	9.00%	0.01%
Southern Co/The	SO	1,059.80	68.58	72,681.36	0.23%	3.85%	0.01%	6.00%	0.01%
Truist Financial Corp	TFC	1,334.89	58.55	78,157.93	0.24%	3.28%	0.01%	7.00%	0.02%
Southwest Airlines Co	LUV	591.92	42.84	25,357.85		n/a		34.00%	
W R Berkley Corp	WRB	176.64	82.39	14,553.37	0.05%	0.63%	0.00%	14.50%	0.01%
Stanley Black & Decker Inc	SWK	163.03	188.62	30,751.28	0.10%	1.68%	0.00%	6.00%	0.01%
Public Storage	PSA	175.36	374.56	65,680.97	0.20%	2.14%	0.00%	6.50%	0.01%
Arista Networks Inc	ANET	307.28	143.75	44,172.08	0.14%	n/a		4.50%	0.01%
Sysco Corp	SY	512.66	78.55	40,269.13	0.13%	2.39%	0.00%	17.00%	0.02%
Corteva Inc	CTVA	730.27	47.28	34,527.02		1.18%			
Texas Instruments Inc	TXN	923.53	188.47	174,056.95	0.54%	2.44%	0.01%	9.00%	0.05%
Textron Inc	TXT	220.43	77.20	17,016.81	0.05%	0.10%	0.00%	8.50%	0.00%
Thermo Fisher Scientific Inc	TMO	394.05	667.24	262,924.59	0.82%	0.16%	0.00%	15.00%	0.12%
TJX Cos Inc/The	TJX	1,192.88	75.92	90,563.30	0.28%	1.37%	0.00%	20.00%	0.06%
Globe Life Inc	GL	100.98	93.72	9,463.75	0.03%	0.84%	0.00%	8.00%	0.00%
Johnson Controls International plc	JCI	704.33	81.31	57,269.23	0.18%	1.67%	0.00%	14.00%	0.02%
Ulta Beauty Inc	ULTA	54.12	412.34	22,315.84	0.07%	n/a		15.50%	0.01%
Union Pacific Corp	UNP	642.88	251.93	161,959.75	0.50%	1.87%	0.01%	10.00%	0.05%
Keysight Technologies Inc	KEYS	183.04	206.51	37,800.00	0.12%	n/a		17.00%	0.02%
UnitedHealth Group Inc	UNH	941.85	502.14	472,941.06	1.47%	1.16%	0.02%	12.00%	0.18%
Marathon Oil Corp	MRO	778.54	16.42	12,783.58		1.46%			
Bio-Rad Laboratories Inc	BIO	24.84	755.57	18,765.34	0.06%	n/a		11.50%	0.01%
Ventas Inc	VTR	399.18	51.12	20,405.88	0.06%	3.52%	0.00%	4.50%	0.00%
VF Corp	VFC	392.78	73.22	28,759.50	0.09%	2.73%	0.00%	9.50%	0.01%
Vornado Realty Trust	VNO	191.68	41.86	8,023.77		5.06%		-22.50%	
Vulcan Materials Co	VMC	132.71	207.58	27,546.90	0.09%	0.71%	0.00%	10.00%	0.01%
Weyerhaeuser Co	WY	749.05	41.18	30,845.67		1.65%		22.00%	
Whirlpool Corp	WHR	60.74	234.66	14,253.95	0.04%	2.39%	0.00%	9.50%	0.00%
Williams Cos Inc/The	WMB	1,215.03	26.04	31,639.38	0.10%	6.30%	0.01%	10.50%	0.01%
WEC Energy Group Inc	WEC	315.44	97.07	30,619.28	0.10%	3.00%	0.00%	6.50%	0.01%
Adobe Inc	ADBE	475.80	567.06	269,807.15	0.84%	n/a		15.50%	0.13%
AES Corp/The	AES	666.71	24.30	16,201.15		2.60%		24.00%	
Amgen Inc	AMGN	563.27	224.97	126,717.95	0.39%	3.45%	0.01%	5.50%	0.02%
Apple Inc	AAPL	16,406.40	177.57	2,913,283.92	9.06%	0.50%	0.04%	13.00%	1.18%
Autodesk Inc	ADSK	219.97	281.19	61,854.21	0.19%	n/a		18.00%	0.03%
Cintas Corp	CTAS	103.66	443.17	45,940.77	0.14%	0.86%	0.00%	13.50%	0.02%
Comcast Corp	CMCSA	4,559.48	50.33	229,478.58	0.71%	1.99%	0.01%	11.00%	0.08%
Molson Coors Beverage Co	TAP	200.59	46.35	9,297.11		2.93%		41.00%	
KLA Corp	KLAC	151.62	430.11	65,214.14	0.20%	0.98%	0.00%	19.50%	0.04%
Marriott International Inc/MD	MAR	325.68	165.24	53,815.86	0.17%	n/a		17.50%	0.03%
McCormick & Co Inc/MD	MKC	249.35	96.61	24,089.90	0.07%	1.53%	0.00%	6.00%	0.00%
PACCAR Inc	PCAR	347.18	88.26	30,641.84	0.10%	1.54%	0.00%	5.00%	0.00%
Costco Wholesale Corp	COST	443.43	567.70	251,736.35	0.78%	0.56%	0.00%	10.50%	0.08%
First Republic Bank/CA	FRC	179.06	206.51	36,977.68	0.11%	0.43%	0.00%	13.50%	0.02%
Stryker Corp	SYK	377.24	267.42	100,881.52	0.31%	1.04%	0.00%	11.00%	0.03%
Tyson Foods Inc	TSN	293.07	87.16	25,544.07	0.08%	2.11%	0.00%	6.00%	0.00%
Lamb Weston Holdings Inc	LW	146.07	63.38	9,257.79	0.03%	1.55%	0.00%	6.00%	0.00%
Applied Materials Inc	AMAT	888.51	157.36	139,816.41	0.43%	0.61%	0.00%	16.50%	0.07%
American Airlines Group Inc	AAL	647.52	17.96	11,629.37		n/a			
Cardinal Health Inc	CAH	281.79	51.49	14,509.26	0.05%	3.81%	0.00%	12.00%	0.01%
Cerner Corp	CERN	292.21	92.87	27,137.64	0.08%	1.16%	0.00%	11.00%	0.01%
Cincinnati Financial Corp	CINF	161.14	113.93	18,358.79	0.06%	2.21%	0.00%	17.50%	0.01%
ViacomCBS Inc	VIAC	606.71	30.18	18,310.39	0.06%	3.18%	0.00%	7.00%	0.00%
DR Horton Inc	DHI	356.18	108.45	38,627.83	0.12%	0.83%	0.00%	11.00%	0.01%
Electronic Arts Inc	EA	282.81	131.90	37,302.38	0.12%	0.52%	0.00%	12.50%	0.01%

## STANDARD AND POOR'S 500 INDEX

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Expeditors International of Washington Inc	EXPD	169.40	134.29	22,749.26	0.07%	0.86%	0.00%	10.00%	0.01%
Fastenal Co	FAST	575.16	64.06	36,844.94	0.11%	1.75%	0.00%	9.00%	0.01%
M&T Bank Corp	MTB	128.69	153.58	19,763.44	0.06%	3.13%	0.00%	8.00%	0.00%
Xcel Energy Inc	XEL	538.68	67.70	36,468.37	0.11%	2.70%	0.00%	6.00%	0.01%
Fiserv Inc	FISV	660.23	103.79	68,525.48	0.21%	n/a		13.00%	0.03%
Fifth Third Bancorp	FITB	683.76	43.55	29,777.62	0.09%	2.76%	0.00%	9.50%	0.01%
Gilead Sciences Inc	GILD	1,254.38	72.61	91,080.82	0.28%	3.91%	0.01%	3.50%	0.01%
Hasbro Inc	HAS	137.95	101.78	14,040.25	0.04%	2.67%	0.00%	11.50%	0.01%
Huntington Bancshares Inc/OH	HBAN	1,446.46	15.42	22,304.43	0.07%	4.02%	0.00%	9.00%	0.01%
Welltower Inc	WELL	435.28	85.77	37,333.54		2.84%		-1.50%	
Biogen Inc	BIIB	146.89	239.92	35,242.57	0.11%	n/a		7.00%	0.01%
Northern Trust Corp	NTRS	207.66	119.61	24,838.33	0.08%	2.34%	0.00%	7.00%	0.01%
Packaging Corp of America	PKG	94.99	136.15	12,933.02	0.04%	2.94%	0.00%	9.00%	0.00%
Paychex Inc	PAYX	360.76	136.50	49,243.33	0.15%	1.93%	0.00%	8.00%	0.01%
People's United Financial Inc	PBCT	428.03	17.82	7,627.41	0.02%	4.10%	0.00%	2.50%	0.00%
QUALCOMM Inc	QCOM	1,120.00	182.87	204,814.40	0.64%	1.49%	0.01%	18.50%	0.12%
Roper Technologies Inc	ROP	105.49	491.86	51,883.85	0.16%	0.50%	0.00%	8.50%	0.01%
Ross Stores Inc	ROST	353.33	114.28	40,378.55	0.13%	1.00%	0.00%	14.00%	0.02%
IDEXX Laboratories Inc	IDXX	84.79	658.46	55,833.46	0.17%	n/a		14.50%	0.03%
Starbucks Corp	SBUX	1,173.20	116.97	137,229.20	0.43%	1.68%	0.01%	16.00%	0.07%
KeyCorp	KEY	931.06	23.13	21,535.37	0.07%	3.37%	0.00%	9.50%	0.01%
Fox Corp	FOXA	320.35	36.90	11,820.80	0.04%	1.30%	0.00%	10.50%	0.00%
Fox Corp	FOX	249.24	34.27	8,541.45		1.40%			
State Street Corp	STT	365.63	93.00	34,003.50	0.11%	2.45%	0.00%	7.50%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	416.89	20.74	8,646.32		n/a			
US Bancorp	USB	1,482.80	56.17	83,288.76	0.26%	3.28%	0.01%	6.50%	0.02%
A O Smith Corp	AOS	133.19	85.85	11,434.10	0.04%	1.30%	0.00%	10.00%	0.00%
NortonLifeLock Inc	NLOK	581.86	25.98	15,116.67	0.05%	1.92%	0.00%	11.00%	0.01%
T Rowe Price Group Inc	TROW	224.75	196.64	44,195.04	0.14%	2.20%	0.00%	12.00%	0.02%
Waste Management Inc	WM	418.32	166.90	69,816.94	0.22%	1.38%	0.00%	7.50%	0.02%
Constellation Brands Inc	STZ	164.26	250.97	41,225.34	0.13%	1.21%	0.00%	7.00%	0.01%
Xilinx Inc	XLNX	247.88	212.03	52,558.00	0.16%	0.70%	0.00%	8.50%	0.01%
DENTSPLY SIRONA Inc	XRAY	218.61	55.79	12,196.08	0.04%	0.79%	0.00%	5.50%	0.00%
Zions Bancorp NA	ZION	156.46	63.16	9,882.20	0.03%	2.41%	0.00%	7.50%	0.00%
Alaska Air Group Inc	ALK	125.31	52.10	6,528.70		n/a		78.00%	
Invesco Ltd	IVZ	461.21	23.02	10,616.99	0.03%	2.95%	0.00%	15.50%	0.01%
Linde PLC	LIN	511.29	346.43	177,124.81		1.22%			
Intuit Inc	INTU	283.17	643.22	182,138.68	0.57%	0.42%	0.00%	15.00%	0.08%
Morgan Stanley	MS	1,794.41	98.16	176,139.48	0.55%	2.85%	0.02%	10.50%	0.06%
Microchip Technology Inc	MCHP	554.87	87.06	48,307.07	0.15%	1.07%	0.00%	10.50%	0.02%
Chubb Ltd	CB	430.74	193.31	83,266.54	0.26%	1.66%	0.00%	12.50%	0.03%
Hologic Inc	HOLX	251.42	76.56	19,248.79		n/a		25.00%	
Citizens Financial Group Inc	CFG	426.20	47.25	20,137.95	0.06%	3.30%	0.00%	8.50%	0.01%
O'Reilly Automotive Inc	ORLY	67.38	706.23	47,584.36	0.15%	n/a		13.00%	0.02%
Allstate Corp/The	ALL	286.68	117.65	33,727.43	0.10%	2.75%	0.00%	5.00%	0.01%
Equity Residential	EQR	375.02	90.50	33,938.95	0.11%	2.66%	0.00%	2.00%	0.00%
BorgWarner Inc	BWA	239.77	45.07	10,806.48	0.03%	1.51%	0.00%	8.00%	0.00%
Organon & Co	OGN	253.55	30.45	7,720.60		3.68%			
Host Hotels & Resorts Inc	HST	714.04	17.39	12,417.07	0.04%	n/a		10.00%	0.00%
Incyte Corp	INCY	220.89	73.40	16,213.40		n/a		58.50%	
Simon Property Group Inc	SPG	328.61	159.77	52,502.18	0.16%	4.13%	0.01%	1.50%	0.00%
Eastman Chemical Co	EMN	134.44	120.91	16,255.14	0.05%	2.51%	0.00%	10.50%	0.01%
Twitter Inc	TWTR	799.61	43.22	34,559.14		n/a		39.00%	
AvalonBay Communities Inc	AVB	139.74	252.59	35,297.18	0.11%	2.52%	0.00%	1.50%	0.00%
Prudential Financial Inc	PRU	378.00	108.24	40,914.72	0.13%	4.25%	0.01%	4.50%	0.01%
United Parcel Service Inc	UPS	729.16	214.34	156,287.73	0.49%	1.90%	0.01%	11.50%	0.06%
Walgreens Boots Alliance Inc	WBA	863.95	52.16	45,063.37	0.14%	3.66%	0.01%	7.50%	0.01%
STERIS PLC	STE	100.02	243.41	24,346.60	0.08%	0.71%	0.00%	12.00%	0.01%
McKesson Corp	MCK	152.68	248.57	37,952.16	0.12%	0.76%	0.00%	9.50%	0.01%
Lockheed Martin Corp	LMT	275.79	355.41	98,017.10	0.30%	3.15%	0.01%	7.50%	0.02%
AmerisourceBergen Corp	ABC	208.13	132.89	27,658.79	0.09%	1.38%	0.00%	6.50%	0.01%
Capital One Financial Corp	COF	425.62	145.09	61,753.50		1.65%			
Waters Corp	WAT	61.04	372.60	22,742.01	0.07%	n/a		6.00%	0.00%
Dollar Tree Inc	DLTR	224.96	140.52	31,610.82	0.10%	n/a		8.50%	0.01%
Darden Restaurants Inc	DRI	129.79	150.64	19,550.81	0.06%	2.92%	0.00%	19.50%	0.01%
Match Group Inc	MTCH	283.09	132.25	37,437.99	0.12%	n/a		18.50%	0.02%
Domino's Pizza Inc	DPZ	36.39	564.33	20,534.28	0.06%	0.67%	0.00%	15.00%	0.01%
NVR Inc	NVR	3.48	5,908.87	20,580.59	0.06%	n/a		9.00%	0.01%
NetApp Inc	NTAP	222.28	91.99	20,447.35	0.06%	2.17%	0.00%	8.00%	0.01%
Citrix Systems Inc	CTXS	124.72	94.59	11,797.55	0.04%	1.56%	0.00%	8.00%	0.00%
DXC Technology Co	DXC	252.24	32.19	8,119.57	0.03%	n/a		6.50%	0.00%
Old Dominion Freight Line Inc	ODFL	115.01	358.38	41,217.64	0.13%	0.22%	0.00%	11.50%	0.01%
DaVita Inc	DVA	101.90	113.76	11,592.14	0.04%	n/a		16.00%	0.01%
Hartford Financial Services Group Inc/The	HIG	340.35	69.04	23,497.97	0.07%	2.23%	0.00%	6.50%	0.00%
Iron Mountain Inc	IRM	289.55	52.33	15,152.10	0.05%	4.73%	0.00%	8.50%	0.00%
Estee Lauder Cos Inc/The	EL	231.71	370.20	85,777.19	0.27%	0.65%	0.00%	11.50%	0.03%
Cadence Design Systems Inc	CDNS	277.14	186.35	51,645.23	0.16%	n/a		12.00%	0.02%
Tyler Technologies Inc	TYL	40.98	537.95	22,043.04	0.07%	n/a		14.00%	0.01%
Universal Health Services Inc	UHS	73.12	129.66	9,480.74	0.03%	0.62%	0.00%	11.00%	0.00%
Skyworks Solutions Inc	SKWS	165.39	155.14	25,658.14	0.08%	1.44%	0.00%	16.00%	0.01%
Quest Diagnostics Inc	DGX	122.68	173.01	21,224.00	0.07%	1.43%	0.00%	7.50%	0.00%
Activision Blizzard Inc	ATVI	778.89	66.53	51,819.49	0.16%	0.71%	0.00%	13.00%	0.02%
Rockwell Automation Inc	ROK	116.01	348.85	40,471.14	0.13%	1.28%	0.00%	10.00%	0.01%
Kraft Heinz Co/The	KHC	1,224.04	35.90	43,943.11	0.14%	4.46%	0.01%	1.50%	0.00%
American Tower Corp	AMT	455.41	292.50	133,208.60	0.41%	1.90%	0.01%	9.50%	0.04%
Regeneron Pharmaceuticals Inc	REGN	105.72	631.52	66,764.29	0.21%	n/a		12.50%	0.03%
Amazon.com Inc	AMZN	507.15	3,334.34	1,691,003.86		n/a		30.00%	
Jack Henry & Associates Inc	JKHY	74.04	166.99	12,364.11	0.04%	1.10%	0.00%	10.50%	0.00%
Ralph Lauren Corp	RL	48.74	118.86	5,792.76	0.02%	2.31%	0.00%	11.50%	0.00%
Boston Properties Inc	BXP	156.21	115.18	17,991.92		3.40%		-2.00%	

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outstg	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Amphenol Corp	APH	598.03	87.46	52,303.53	0.16%	0.91%	0.00%	12.00%	0.02%
Howmet Aerospace Inc	HWM	427.22	31.83	13,598.35	0.04%	0.25%	0.00%	12.00%	0.01%
Pioneer Natural Resources Co	PXD	244.13	181.88	44,403.09	0.14%	1.36%	0.00%	20.00%	0.03%
Valero Energy Corp	VLO	408.84	75.11	30,707.67	0.10%	5.22%	0.00%	13.00%	0.01%
Synopsys Inc	SNPS	153.44	368.50	56,541.90	0.18%	n/a		13.00%	0.02%
Etsy Inc	ETSY	126.78	218.94	27,757.43		n/a		29.00%	
CH Robinson Worldwide Inc	CHRW	129.99	107.63	13,990.50	0.04%	2.04%	0.00%	9.00%	0.00%
Accenture PLC	ACN	658.33	414.55	272,911.95	0.85%	0.94%	0.01%	10.00%	0.08%
TransDigm Group Inc	TDG	55.25	636.28	35,153.83	0.11%	n/a		16.50%	0.02%
Yum! Brands Inc	YUM	293.13	138.86	40,704.45	0.13%	1.44%	0.00%	11.00%	0.01%
Prologis Inc	PLD	739.75	168.36	124,543.47	0.39%	1.50%	0.01%	8.50%	0.03%
FirstEnergy Corp	FE	544.42	41.59	22,642.43	0.07%	3.75%	0.00%	11.50%	0.01%
VeriSign Inc	VRSN	111.08	253.82	28,193.82	0.09%	n/a		8.50%	0.01%
Quanta Services Inc	PWR	142.50	114.66	16,338.94	0.05%	0.24%	0.00%	12.50%	0.01%
Henry Schein Inc	HSIC	138.67	77.53	10,751.40	0.03%	n/a		6.50%	0.00%
Ameren Corp	AEE	255.41	89.01	22,734.04	0.07%	2.47%	0.00%	6.50%	0.00%
ANSYS Inc	ANSS	87.25	401.12	34,998.92	0.11%	n/a		8.00%	0.01%
FactSet Research Systems Inc	FDS	37.64	486.01	18,294.39	0.06%	0.67%	0.00%	9.50%	0.01%
NVIDIA Corp	NVDA	2,500.00	294.11	735,275.00	2.29%	0.05%	0.00%	20.00%	0.46%
Sealed Air Corp	SEE	148.16	67.47	9,996.15	0.03%	1.19%	0.00%	13.50%	0.00%
Cognizant Technology Solutions Corp	CTSH	525.25	88.72	46,600.36	0.14%	1.08%	0.00%	7.00%	0.01%
SVB Financial Group	SIVB	58.69	678.24	39,803.87	0.12%	n/a		5.00%	0.01%
Intuitive Surgical Inc	ISRG	357.24	359.30	128,355.25	0.40%	n/a		16.00%	0.06%
Take-Two Interactive Software Inc	TWTO	115.30	177.72	20,491.12	0.06%	n/a		12.00%	0.01%
Republic Services Inc	RSRG	317.10	139.45	44,218.90	0.14%	1.32%	0.00%	11.00%	0.02%
eBay Inc	EBAY	628.00	66.50	41,629.27	0.13%	1.08%	0.00%	16.50%	0.02%
Goldman Sachs Group Inc/The	GS	334.79	382.55	128,075.06	0.40%	2.09%	0.01%	8.50%	0.03%
SBA Communications Corp	SBAC	108.78	389.02	42,317.98		0.60%		45.00%	
Sempra Energy	SRE	315.07	132.28	41,677.59	0.13%	3.33%	0.00%	10.00%	0.01%
Moody's Corp	MCO	185.90	390.58	72,608.82	0.23%	0.63%	0.00%	10.00%	0.02%
Booking Holdings Inc	BKNG	41.06	2,399.23	98,519.58	0.31%	n/a		14.00%	0.04%
F5 Inc	FFIV	61.23	244.71	14,983.35	0.05%	n/a		7.00%	0.00%
Akamai Technologies Inc	AKAM	162.48	117.04	19,016.66	0.06%	n/a		9.50%	0.01%
Charles River Laboratories International Inc	CRL	50.46	376.78	19,013.83	0.06%	n/a		7.00%	0.00%
MarketAxess Holdings Inc	MKTX	38.03	411.27	15,638.95	0.05%	0.64%	0.00%	14.00%	0.01%
Devon Energy Corp	DVN	677.00	44.05	29,821.85		7.63%		29.50%	
Alphabet Inc	GOOGL	300.81	2,897.04	871,458.60		n/a			
Bio-Techne Corp	TECH	39.30	517.34	20,328.88	0.06%	0.25%	0.00%	13.00%	0.01%
Teleflex Inc	TFX	46.85	328.48	15,387.65	0.05%	0.41%	0.00%	15.00%	0.01%
Netflix Inc	NFLX	442.95	602.44	266,852.00		n/a		23.50%	
Allegion plc	ALLE	89.70	132.44	11,879.34	0.04%	1.09%	0.00%	9.50%	0.00%
Agilent Technologies Inc	A	302.00	159.65	48,214.46	0.15%	0.53%	0.00%	12.50%	0.02%
Anthem Inc	ANTM	242.72	463.54	112,508.11	0.35%	0.98%	0.00%	13.00%	0.05%
Trimble Inc	TRMB	251.01	87.19	21,885.39	0.07%	n/a		14.50%	0.01%
CME Group Inc	CME	359.40	228.46	82,107.61	0.26%	1.58%	0.00%	8.50%	0.02%
Juniper Networks Inc	JNPR	325.18	35.71	11,612.21	0.04%	2.24%	0.00%	7.00%	0.00%
BlackRock Inc	BLK	151.92	915.56	139,089.13	0.43%	1.80%	0.01%	11.00%	0.05%
DTE Energy Co	DTE	193.75	119.54	23,161.11	0.07%	2.96%	0.00%	1.00%	0.00%
Nasdaq Inc	NDAQ	167.22	210.01	35,118.29	0.11%	1.03%	0.00%	6.50%	0.01%
Celanese Corp	CE	108.87	168.06	18,296.86	0.06%	1.62%	0.00%	6.50%	0.00%
Philip Morris International Inc	PM	1,556.83	95.00	147,898.66	0.46%	5.26%	0.02%	7.00%	0.03%
salesforce.com Inc	CRM	985.00	254.13	250,318.05	0.78%	n/a		20.00%	0.16%
Ingersoll Rand Inc	IR	407.59	61.87	25,217.28		0.13%			
Huntington Ingalls Industries Inc	HII	40.06	186.74	7,480.99	0.02%	2.53%	0.00%	7.00%	0.00%
MetLife Inc	MET	841.16	62.49	52,564.09	0.16%	3.07%	0.01%	6.50%	0.01%
Under Armour Inc	UA	253.02	18.04	4,564.46		n/a			
Tapestry Inc	TPR	275.14	40.60	11,170.81	0.03%	2.46%	0.00%	10.00%	0.00%
CSX Corp	CSX	2,217.98	37.60	83,396.16	0.26%	0.99%	0.00%	11.50%	0.03%
Edwards Lifesciences Corp	EW	624.33	129.55	80,882.47	0.25%	n/a		13.00%	0.03%
Ameriprise Financial Inc	AMP	111.89	301.66	33,752.74	0.10%	1.50%	0.00%	13.50%	0.01%
Zebra Technologies Corp	ZBRA	53.44	595.20	31,808.08	0.10%	n/a		13.00%	0.01%
Zimmer Biomet Holdings Inc	ZBH	208.91	127.04	26,539.67	0.08%	0.76%	0.00%	8.50%	0.01%
CBRE Group Inc	CBRE	334.67	108.51	36,314.61	0.11%	n/a		10.50%	0.01%
Mastercard Inc	MA	974.71	359.32	350,232.44	1.09%	0.55%	0.01%	13.00%	0.14%
CarMax Inc	KMX	161.87	130.23	21,080.59	0.07%	n/a		12.50%	0.01%
Intercontinental Exchange Inc	ICE	563.40	136.77	77,056.77	0.24%	0.97%	0.00%	8.00%	0.02%
Fidelity National Information Services Inc	FIS	608.94	109.15	66,465.47		1.43%		28.00%	
Chipotle Mexican Grill Inc	CMG	28.14	1,748.25	49,187.01		n/a		22.00%	
Wynn Resorts Ltd	WYNN	115.66	85.04	9,835.56		n/a		27.00%	
Live Nation Entertainment Inc	LYV	224.66	119.69	26,889.56		n/a			
Assurant Inc	AIZ	56.98	155.86	8,880.44	0.03%	1.75%	0.00%	15.50%	0.00%
NRG Energy Inc	NRG	244.84	43.08	10,547.66		3.02%		-1.50%	
Regions Financial Corp	RF	953.28	21.80	20,781.57	0.06%	3.12%	0.00%	9.50%	0.01%
Monster Beverage Corp	MNST	529.14	96.04	50,818.51	0.16%	n/a		11.50%	0.02%
Mosaic Co/The	MOS	370.41	39.29	14,553.41		1.15%		56.50%	
Baker Hughes Co	BKR	871.08	24.06	20,958.18		2.99%			
Expedia Group Inc	EXPE	146.00	180.72	26,385.84		n/a			
Evergy Inc	EVERG	226.99	68.61	15,573.99	0.05%	3.34%	0.00%	8.00%	0.00%
Discovery Inc	DISCA	169.21	23.54	3,983.13	0.01%	n/a		13.50%	0.00%
CF Industries Holdings Inc	CF	214.48	70.78	15,180.54	0.05%	1.70%	0.00%	19.50%	0.01%
Leidos Holdings Inc	LDOS	140.34	88.90	12,476.14	0.04%	1.62%	0.00%	9.00%	0.00%
APA Corp	APA	363.27	26.89	9,768.44		1.86%			
Alphabet Inc	GOOG	317.74	2,893.59	919,403.50		n/a		23.50%	
TE Connectivity Ltd	TEL	326.31	161.34	52,647.34	0.16%	1.39%	0.00%	10.00%	0.02%
Cooper Cos Inc/The	COO	49.41	418.94	20,698.99	0.06%	0.01%	0.00%	19.00%	0.01%
Discover Financial Services	DFS	293.08	115.56	33,867.86	0.11%	1.73%	0.00%	16.00%	0.02%
Visa Inc	V	1,667.42	216.71	361,345.72	1.12%	0.69%	0.01%	12.00%	0.13%
Mid-America Apartment Communities Inc	MAA	115.14	229.44	26,417.26	0.08%	1.90%	0.00%	9.00%	0.01%
Xylem Inc/NY	XYL	180.33	119.92	21,624.57	0.07%	0.93%	0.00%	6.50%	0.00%
Marathon Petroleum Corp	MPC	615.59	63.99	39,391.48		3.63%			

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outstg	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Tractor Supply Co	TSCO	113.82	238.60	27,156.26	0.08%	0.87%	0.00%	11.00%	0.01%
Advanced Micro Devices Inc	AMD	1,207.61	143.90	173,775.08		n/a		30.00%	
ResMed Inc	RMD	145.72	260.48	37,957.93	0.12%	0.64%	0.00%	8.50%	0.01%
Mettler-Toledo International Inc	MTD	22.99	1,697.21	39,012.07	0.12%	n/a		12.50%	0.02%
Copart Inc	CPRT	237.19	151.62	35,962.44	0.11%	n/a		12.00%	0.01%
Albemarle Corp	ALB	116.98	233.77	27,345.48	0.09%	0.67%	0.00%	6.50%	0.01%
Fortinet Inc	FTNT	163.50	359.40	58,761.90		n/a		21.00%	
Moderna Inc	MRNA	405.45	253.98	102,976.19		n/a			
Essex Property Trust Inc	ESS	65.09	352.23	22,925.95		2.37%		-0.50%	
Realty Income Corp	O	565.81	71.59	40,506.55	0.13%	4.13%	0.01%	3.50%	0.00%
Westrock Co	WRK	263.09	44.36	11,670.58	0.04%	2.25%	0.00%	18.50%	0.01%
IHS Markit Ltd	INFO	398.84	132.92	53,013.95	0.16%	0.60%	0.00%	10.50%	0.02%
Westinghouse Air Brake Technologies Corp	WAB	186.82	92.11	17,208.08	0.05%	0.52%	0.00%	9.50%	0.01%
Pool Corp	POOL	40.09	566.00	22,689.81	0.07%	0.57%	0.00%	17.00%	0.01%
Western Digital Corp	WDC	311.62	65.21	20,320.94	0.06%	n/a		9.00%	0.01%
PepsiCo Inc	PEP	1,382.65	173.71	240,180.65	0.75%	2.48%	0.02%	6.50%	0.05%
Diamondback Energy Inc	FANG	181.18	107.85	19,539.72		1.85%			
ServiceNow Inc	NOW	199.00	649.11	129,172.89		n/a		44.50%	
Church & Dwight Co Inc	CHD	244.15	102.50	25,025.17	0.08%	0.99%	0.00%	8.00%	0.01%
Duke Realty Corp	DRE	380.85	65.64	24,998.99		1.71%		-2.00%	
Federal Realty Investment Trust	FRT	77.79	136.32	10,604.20	0.03%	3.14%	0.00%	2.00%	0.00%
MGM Resorts International	MGM	468.96	44.88	21,046.92		0.02%		25.00%	
American Electric Power Co Inc	AEP	503.65	88.97	44,809.92	0.14%	3.51%	0.00%	6.50%	0.01%
SolarEdge Technologies Inc	SEDG	52.52	280.57	14,735.54	0.05%	n/a		19.50%	0.01%
PTC Inc	PTC	117.87	121.15	14,280.19		n/a			
JB Hunt Transport Services Inc	JBHT	105.01	204.40	21,464.86	0.07%	0.59%	0.00%	10.00%	0.01%
Lam Research Corp	LRCX	140.80	719.15	101,255.60	0.31%	0.83%	0.00%	17.50%	0.06%
Mohawk Industries Inc	MHK	67.73	182.18	12,339.42	0.04%	n/a		10.50%	0.00%
Pentair PLC	PNR	165.48	73.03	12,084.86	0.04%	1.15%	0.00%	14.00%	0.01%
Vertex Pharmaceuticals Inc	VRTX	254.25	219.60	55,833.74	0.17%	n/a		18.50%	0.03%
Amcor PLC	AMCR	1,533.17	12.01	18,413.36	0.06%	4.00%	0.00%	15.00%	0.01%
Meta Platforms Inc	FB	2,366.28	336.35	795,897.61		n/a		21.50%	
T-Mobile US Inc	TMUS	1,249.05	115.98	144,865.28	0.45%	n/a		8.50%	0.04%
United Rentals Inc	URI	72.39	332.29	24,055.80	0.07%	n/a		12.50%	0.01%
ABIOMED Inc	ABMD	45.50	359.17	16,341.16	0.05%	n/a		9.50%	0.00%
Honeywell International Inc	HON	688.42	208.51	143,543.08	0.45%	1.88%	0.01%	11.00%	0.05%
Alexandria Real Estate Equities Inc	ARE	154.96	222.96	34,550.77	0.11%	2.06%	0.00%	12.00%	0.01%
Delta Air Lines Inc	DAL	640.01	39.08	25,011.75		n/a		49.00%	
Seagate Technology Holdings PLC	STX	222.64	112.98	25,153.42	0.08%	2.48%	0.00%	15.00%	0.01%
United Airlines Holdings Inc	UAL	323.61	43.78	14,167.69		n/a			
News Corp	NWS	199.63	22.50	4,491.68		0.89%			
Centene Corp	CNC	583.50	82.40	48,080.65	0.15%	n/a		9.50%	0.01%
Martin Marietta Materials Inc	MLM	62.38	440.52	27,480.52	0.09%	0.55%	0.00%	10.50%	0.01%
Teradyne Inc	TER	163.00	163.53	26,656.04	0.08%	0.24%	0.00%	13.50%	0.01%
PayPal Holdings Inc	PYPL	1,174.93	188.58	221,568.30	0.69%	n/a		16.00%	0.11%
Tesla Inc	TSLA	1,004.27	1,056.78	1,061,287.17		n/a			
DISH Network Corp	DISH	290.36	32.44	9,419.18	0.03%	n/a		4.00%	0.00%
Dow Inc	DOW	739.61	56.72	41,950.91		4.94%			
Penn National Gaming Inc	PENN	169.51	51.85	8,789.30		n/a		30.00%	
Everest Re Group Ltd	RE	39.37	273.92	10,783.96	0.03%	2.26%	0.00%	11.00%	0.00%
Teledyne Technologies Inc	TDY	46.66	436.89	20,383.10	0.06%	n/a		15.00%	0.01%
News Corp	NWSA	393.04	22.31	8,768.68		0.90%			
Exelon Corp	EXC	976.76	57.76	56,417.66	0.18%	2.65%	0.00%	5.50%	0.01%
Global Payments Inc	GPN	290.15	135.18	39,222.61	0.12%	0.74%	0.00%	16.50%	0.02%
Crown Castle International Corp	CCI	432.20	208.74	90,218.05	0.28%	2.82%	0.01%	8.50%	0.02%
Aptiv PLC	APTIV	270.51	164.95	44,621.28		n/a		21.50%	
Advance Auto Parts Inc	AAP	62.36	239.88	14,957.72	0.05%	1.67%	0.00%	11.00%	0.01%
Align Technology Inc	ALGN	78.85	657.18	51,820.61	0.16%	n/a		17.00%	0.03%
Illumina Inc	ILMN	156.30	380.44	59,462.77	0.18%	n/a		10.00%	0.02%
LKQ Corp	LKQ	291.49	60.03	17,498.20	0.05%	1.67%	0.00%	14.00%	0.01%
Nielsen Holdings PLC	NLSN	358.93	20.51	7,361.59		1.17%			
Zoetis Inc	ZTS	473.13	244.03	115,456.94	0.36%	0.53%	0.00%	12.00%	0.04%
Equinix Inc	EQIX	90.04	845.84	76,160.28	0.24%	1.36%	0.00%	17.00%	0.04%
Digital Realty Trust Inc	DLR	283.79	176.87	50,193.41	0.16%	2.62%	0.00%	8.50%	0.01%
Las Vegas Sands Corp	LVS	763.99	37.64	28,756.58	0.09%	n/a		17.00%	0.02%
Discovery Inc	DISCK	330.15	22.90	7,560.34		n/a			

Notes:

- [1] Equals sum of Col. [9]
- [2] Equals sum of Col. [11]
- [3] Equals (([1] x (1 + (0.5 x [2]))) + [2])
- [4] Source: Bloomberg Professional as of December 31, 2021
- [5] Source: Bloomberg Professional as of December 31, 2021
- [6] Equals [4] x [5]
- [7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
- [8] Source: Bloomberg Professional, as of December 31, 2021
- [9] Equals [7] x [8]
- [10] Source: Value Line, as of December 31, 2021
- [11] Equals [7] x [10]

Docket No. UE 399  
Exhibit PAC/308  
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Ann E. Bulkley  
Risk Premium Approach**

**March 2022**

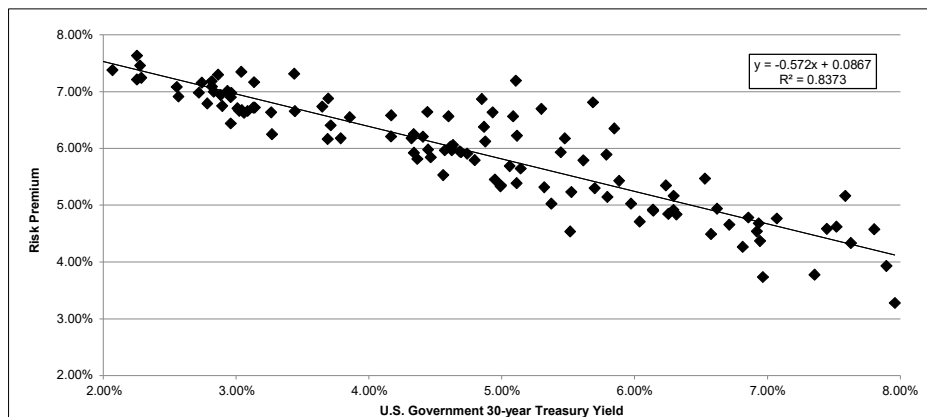
Risk Premium -- Vertically Integrated Electric Utilities

	[1]	[2]	[3]
	Average		
	Authorized VI	U.S. Govt. 30-	
	Electric ROE	year Treasury	Risk Premium
1992.1	12.38%	7.80%	4.58%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.52%	5.23%
2001.4	11.99%	5.30%	6.70%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.65%	5.08%	6.57%
2002.4	11.57%	4.93%	6.64%
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%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	11.24%	4.86%	6.38%
2005.1	10.63%	4.69%	5.93%
2005.2	10.31%	4.47%	5.85%
2005.3	11.08%	4.44%	6.65%
2005.4	10.63%	4.68%	5.95%
2006.1	10.70%	4.63%	6.06%
2006.2	10.79%	5.14%	5.65%
2006.3	10.35%	4.99%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.80%
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%	5.97%
2008.3	10.43%	4.44%	5.98%
2008.4	10.39%	3.65%	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%	6.26%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.36%	5.82%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.21%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.69%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.93%	7.02%
2012.3	9.90%	2.74%	7.16%

Risk Premium -- Vertically Integrated Electric Utilities

	[1]	[2]	[3]
	Average		
	Authorized VI	U.S. Govt. 30-	
	Electric ROE	year Treasury	Risk Premium
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%	6.17%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.26%	6.64%
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%	3.04%	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%	6.71%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.24%
2019.4	9.89%	2.25%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.20%
2020.3	9.30%	1.37%	7.93%
2020.4	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.25%	7.21%
2021.3	9.27%	1.93%	7.34%
2021.4	9.68%	2.00%	7.69%
AVERAGE	10.64%	4.60%	6.04%
MEDIAN	10.59%	4.63%	6.18%





SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.91503
R Square	0.83728
Adjusted R Square	0.83590
Standard Error	0.00420
Observations	120

ANOVA					
	df	SS	MS	F	Significance F
Regression	1	0.010869	0.010869	601.821596	0.000000
Residual	118	0.002131	0.000018		
Total	119	0.013000			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	0.0867	0.001135	76.44	0.0000	0.0845	0.0890	0.0845	0.0890
U.S. Govt. 30-year Treasury	(0.5720)	0.023213	(24.64)	0.0000	(0.6179)	(0.5260)	(0.6179)	(0.5260)

	[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]	1.87%	7.61%	9.47%
Blue Chip Near-Term Projected Forecast (Q2 2022 - Q2 2023) [5]	2.52%	7.23%	9.75%
Blue Chip Long-Term Projected Forecast (2023-2027) [6]	3.40%	6.73%	10.13%
<b>AVERAGE</b>			<b>9.78%</b>

Notes:

- [1] Source: Regulatory Research Associates, rate cases through December 31, 2021
- [2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
- [3] Equals Column [1] - Column [2]
- [4] Source: Bloomberg Professional, 30-day average as of December 31, 2021
- [5] Source: Blue Chip Financial Forecasts, Vol. 41, No. 1, January 1, 2021, at 2
- [6] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14
- [7] See notes [4], [5] & [6]
- [8] Equals  $0.086737 + (-0.571979 \times \text{Column [7]})$
- [9] Equals Column [7] + Column [8]

Docket No. UE 399  
Exhibit PAC/309  
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Ann E. Bulkley  
Capital Expenditures Analysis**

**March 2022**

2022-2026 CAPITAL EXPENDITURES AS A PERCENT OF 2020 NET PLANT  
(\$ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	
		2020	2022	2023	2024	2025	2026	2022-26 Cap. Ex. / 2020 Net Plant	
ALLETE, Inc.	ALE								
	Capital Spending per Share		\$3.70	\$4.10	\$4.50	\$4.50	\$4.50		
	Common Shares Outstanding		52.75	53.38	54.00	54.00	54.00		
	Capital Expenditures		\$195.2	\$218.8	\$243.0	\$243.0	\$243.0	23.61%	1 ALE
	Net Plant	\$4,840.8							
Alliant Energy Corporation	LNT								
	Capital Spending per Share		\$5.30	\$5.90	\$6.50	\$6.50	\$6.50		
	Common Shares Outstanding		251.00	251.75	252.50	252.50	252.50		
	Capital Expenditures		\$1,330.3	\$1,485.3	\$1,641.3	\$1,641.3	\$1,641.3	53.99%	10 LNT
	Net Plant	\$14,336.0							
Ameren Corporation	AEE								
	Capital Spending per Share		\$11.80	\$12.28	\$12.75	\$12.75	\$12.75		
	Common Shares Outstanding		265.00	272.50	280.00	280.00	280.00		
	Capital Expenditures		\$3,127.0	\$3,344.9	\$3,570.0	\$3,570.0	\$3,570.0	64.09%	16 AEE
	Net Plant	\$26,807.0							
American Electric Power Company, Inc.	AEP								
	Capital Spending per Share		\$15.15	\$14.45	\$13.75	\$13.75	\$13.75		
	Common Shares Outstanding		530.00	540.00	550.00	550.00	550.00		
	Capital Expenditures		\$8,029.5	\$7,803.0	\$7,562.5	\$7,562.5	\$7,562.5	60.28%	13 AEP
	Net Plant	\$63,902.0							
Avista Corporation	AVA								
	Capital Spending per Share		\$6.50	\$6.25	\$6.00	\$6.00	\$6.00		
	Common Shares Outstanding		73.50	76.50	79.50	79.50	79.50		
	Capital Expenditures		\$477.8	\$478.1	\$477.0	\$477.0	\$477.0	47.82%	6 AVA
	Net Plant	\$4,991.6							
CMS Energy Corporation	CMS								
	Capital Spending per Share		\$10.35	\$9.43	\$8.50	\$8.50	\$8.50		
	Common Shares Outstanding		289.70	292.35	295.00	295.00	295.00		
	Capital Expenditures		\$2,998.4	\$2,755.4	\$2,507.5	\$2,507.5	\$2,507.5	63.10%	14 CMS
	Net Plant	\$21,039.0							

Duke Energy Corporation	DUK								
Capital Spending per Share		\$16.60	\$16.05	\$15.50	\$15.50	\$15.50			
Common Shares Outstanding		770.00	770.00	770.00	770.00	770.00			
Capital Expenditures		\$12,782.0	\$12,358.5	\$11,935.0	\$11,935.0	\$11,935.0	57.07%	12	DUK
Net Plant		\$106,782.0							
Entergy Corporation	ETR								
Capital Spending per Share		\$18.95	\$19.10	\$19.25	\$19.25	\$19.25			
Common Shares Outstanding		\$205.00	206.50	208.00	208.00	208.00			
Capital Expenditures		\$3,884.8	\$3,944.2	\$4,004.0	\$4,004.0	\$4,004.0	51.07%	8	ETR
Net Plant		\$38,853.0							
Evergy, Inc.	EVRG								
Capital Spending per Share		\$8.75	\$9.63	\$10.50	\$10.50	\$10.50			
Common Shares Outstanding		\$230.00	230.00	230.00	230.00	230.00			
Capital Expenditures		\$2,012.5	\$2,213.8	\$2,415.0	\$2,415.0	\$2,415.0	57.05%	11	EVRG
Net Plant		\$20,106.0							
IDACORP, Inc.	IDA								
Capital Spending per Share		\$7.70	\$8.85	\$10.00	\$10.00	\$10.00			
Common Shares Outstanding		50.45	50.45	50.45	50.45	50.45			
Capital Expenditures		\$388.5	\$446.5	\$504.5	\$504.5	\$504.5	49.87%	7	IDA
Net Plant		\$4,709.5							
NextEra Energy, Inc.	NEE								
Capital Spending per Share		\$7.60	\$8.30	\$9.00	\$9.00	\$9.00			
Common Shares Outstanding		1,980	2,003	2,025	2,025.00	2,025.00			
Capital Expenditures		\$15,048.0	\$16,620.8	\$18,225.0	\$18,225.0	\$18,225.0	94.05%	17	NEE
Net Plant		\$91,803.0							
NorthWestern Corporation	NEW								
Capital Spending per Share		\$9.70	\$8.23	\$6.75	\$6.75	\$6.75			
Common Shares Outstanding		60.00	61.00	62.00	62.00	62.00			
Capital Expenditures		\$582.0	\$501.7	\$418.5	\$418.5	\$418.5	47.23%	4	NEW
Net Plant		\$4,952.9							
Otter Tail Corporation	OTTR								
Capital Spending per Share		\$4.35	\$4.55	\$4.75	\$4.75	\$4.75			
Common Shares Outstanding		\$41.70	41.85	42.00	42.00	42.00			
Capital Expenditures		\$181.4	\$190.4	\$199.5	\$199.5	\$199.5	47.35%	5	OTTR
Net Plant		\$2,049.3							
Portland General Electric Company	POR								
Capital Spending per Share		\$7.45	\$6.85	\$6.25	\$6.25	\$6.25			
Common Shares Outstanding		89.80	89.90	90.00	90.00	90.00			
Capital Expenditures		\$669.0	\$615.8	\$562.5	\$562.5	\$562.5	39.43%	3	POR
Net Plant		\$7,539.0							
Southern Company	SO								
Capital Spending per Share		\$6.35	\$6.18	\$6.00	\$6.00	\$6.00			
Common Shares Outstanding		1,105	1,105	1,105	1,105	1,105			
Capital Expenditures		\$7,016.8	\$6,823.4	\$6,630.0	\$6,630.0	\$6,630.0	38.49%	2	SO
Net Plant		\$87,634.0							
Xcel Energy Inc.	XEL								
Capital Spending per Share		\$9.70	\$9.85	\$10.00	\$10.00	\$10.00			
Common Shares Outstanding		544	549	553	553	553			
Capital Expenditures		\$5,276.8	\$5,402.7	\$5,530.0	\$5,530.0	\$5,530.0	63.49%	15	XEL
Net Plant		\$42,950.0							
PacifiCorp	PacifiCorp								
Capital Expenditures [8]		\$2,000.70	\$3,317.40	\$2,501.20	\$2,025.00	\$2,196.00			
Net Plant [9]		\$22,430.00							
							53.68%	9	PacifiCorp

Notes:

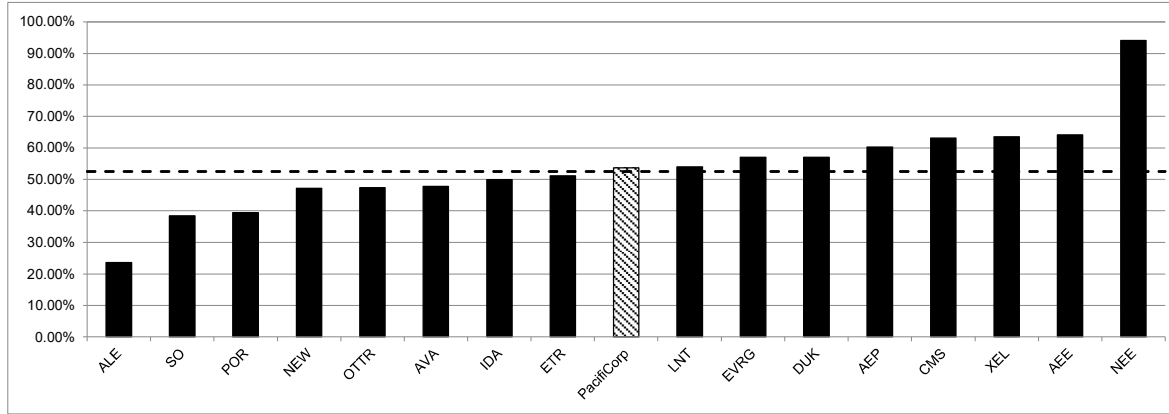
[1] - [6] Value Line November 12, 2021, December 10, 2021, January 21, 2022

[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]

[8] Source: Company Provided Data

[9] Source: Company Provided Data

2022-2026 CAPITAL EXPENDITURES AS A PERCENT OF 2020 NET PLANT



Projected CAPEX / 2020Net Plant

Rank	Company	2022-2026
1	ALLETE, Inc.	ALE 23.61%
2	Southern Company	SO 38.49%
3	Portland General Electric Company	POR 39.43%
4	NorthWestern Corporation	NEW 47.23%
5	Otter Tail Corporation	OTTR 47.35%
6	Avista Corporation	AVA 47.82%
7	IDACORP, Inc.	IDA 49.87%
8	Entergy Corporation	ETR 51.07%
9	PacifiCorp	PacifiCorp 53.68%
10	Alliant Energy Corporation	LNT 53.99%
11	Evergy, Inc.	EVRG 57.05%
12	Duke Energy Corporation	DUK 57.07%
13	American Electric Power Company, Inc.	AEP 60.28%
14	CMS Energy Corporation	CMS 63.10%
15	Xcel Energy Inc.	XEL 63.49%
16	Ameren Corporation	AEE 64.09%
17	NextEra Energy, Inc.	NEE 94.05%
	Proxy Group Median	52.53%
	PacifiCorp/Proxy Group	1.02

Notes:  
Source: Exhibit PAC/309, pages 1-2 col. [7]

Docket No. UE 399  
Exhibit PAC/310  
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Ann E. Bulkley  
Regulatory Risk Analysis**

**March 2022**

**COMPARISON OF PACIFICORP AND PROXY GROUP COMPANIES  
RISK ASSESSMENT**

Proxy Group Company	Operating Subsidiary	Jurisdiction	Service	Fuel Cost Recovery Mechanism	Test Year	Rate Base	Non-Volumetric Rate Design				Capital Cost Recovery	
							Revenue Decoupling	Formula-based rates	Straight Fixed-Variable Rate Design	Non-Volumetric Rate Design		
ALLETE, Inc.	ALLETE (Minnesota Power)	Minnesota	Electric	Yes	Fully Forecast	Average	No	No	No	No	Yes	
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Yes	Historical	Average	No	No	No	No	No	
	Interstate Power & Light Co.	Iowa	Gas	Yes	Historical	Average	No	No	No	No	No	
Ameren Corporation	Wisconsin Power & Light Co.	Wisconsin	Electric	Yes	Fully Forecast	Average	No	No	No	No	No	
	Wisconsin Power & Light Co.	Wisconsin	Gas	Yes	Fully Forecast	Average	No	No	No	No	No	
	Ameren Illinois Co.	Illinois	Electric	N/A	Historical	Year End	No	Yes	No	Yes	No	
	Ameren Illinois Co.	Illinois	Gas	Yes	Fully Forecast	Average	Partial	No	No	Yes	Yes	
	Union Electric Co.	Missouri	Electric	Yes - Sharing Band	Historical	Year End	Partial	No	No	Yes	Yes	
	Union Electric Co.	Missouri	Gas	Yes	Historical	Year End	Partial	No	No	Yes	Yes	
American Electric Power Company, Inc.	Southwestern Electric Power Co.	Arkansas	Electric	Yes	Historical	Year End	Partial	Yes	No	Yes	Yes	
	Indiana Michigan Power Co.	Indiana	Electric	Yes	Fully Forecast	Year End	Partial	No	No	Yes	Yes	
	Kentucky Power Co.	Kentucky	Electric	Yes	Fully Forecast	Year End	Partial	No	No	Yes	No	
	Southwestern Electric Power Co.	Louisiana	Electric	Yes	Historical	Year End	Partial	Yes	No	Yes	No	
	Indiana Michigan Power Co.	Michigan	Electric	Yes	Fully Forecast	Average	No	No	No	No	No	
	Ohio Power Co.	Ohio	Electric	N/A	Partially Forecast	Year End	Partial	No	No	Yes	Yes	
	Public Service Co. of Oklahoma	Oklahoma	Electric	Yes	Historical	Year End	Partial	No	No	Yes	Yes	
	Kingsport Power Co.	Tennessee	Electric	Yes	Fully Forecast	Average	No	No	No	No	No	
	AEP Texas	Texas	Electric	N/A	Historical	Year End	No	No	No	No	Yes	
	Southwestern Electric Power Co.	Texas	Electric	Yes	Historical	Year End	No	No	No	No	Yes	
	Appalachian Power Co.	Virginia	Electric	Yes	Historical	Year End	No	No	No	No	Yes	
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	Yes	Historical	Average	No	No	No	No	No	
	Alaska Electric Light and Power Co.	Alaska	Electric	Yes	Historical	Average	No	No	No	No	No	
	Avista Corporation	Avista Corp.	Idaho	Electric	Yes - Sharing Band	Historical	Year End	Full	No	No	Yes	No
Avista Corp.		Idaho	Gas	Yes	Historical	Year End	Full	No	No	Yes	No	
Avista Corp.		Oregon	Gas	Yes - Sharing Band	Fully Forecast	Year End	Full	No	No	Yes	No	
Avista Corp.		Washington	Electric	Yes - Sharing Band	Historical	Average	Partial	No	No	Yes	No	
Avista Corp.		Washington	Gas	Yes	Historical	Average	Partial	No	No	Yes	No	
CMS Energy Corporation	Consumers Energy Co.	Michigan	Electric	Yes	Fully Forecast	Average	No	No	No	No	No	
	Consumers Energy Co.	Michigan	Gas	Yes	Fully Forecast	Average	Partial	No	No	No	Yes	
Duke Energy Corporation	Duke Energy Florida LLC	Florida	Electric	Yes	Fully Forecast	Year End	No	No	No	No	Yes	
	Duke Energy Indiana LLC	Indiana	Electric	Yes	Historical	Year End	Partial	No	No	Yes	Yes	
	Duke Energy Kentucky Inc.	Kentucky	Electric	Yes	Fully Forecast	Average	Partial	No	No	Yes	No	
	Duke Energy Kentucky Inc.	Kentucky	Gas	Yes	Fully Forecast	Average	Partial	No	No	Yes	No	
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	North Carolina	Electric	Yes	Historical	Year End	No	No	No	No	No	
	Piedmont Natural Gas Co. Inc.	North Carolina	Gas	Yes	Historical	Year End	Full	No	No	Yes	Yes	
	Duke Energy Ohio Inc.	Ohio	Electric	N/A	Partially Forecast	Year End	Partial	No	No	Yes	Yes	
	Duke Energy Ohio Inc.	Ohio	Gas	Yes	Partially Forecast	Year End	No	Yes	Yes	Yes	Yes	
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	South Carolina	Electric	Yes	Historical	Year End	No	No	No	No	No	
	Piedmont Natural Gas Co. Inc.	South Carolina	Gas	Yes	Historical	Year End	Partial	No	No	Yes	No	
	Piedmont Natural Gas Co. Inc.	Tennessee	Gas	Yes	Fully Forecast	Average	Partial	No	No	Yes	Yes	
	Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Yes	Fully Forecast	Average	Partial	Yes	No	Yes	Yes
		Entergy New Orleans LLC	Louisiana-NOCC	Electric	Yes	Partially Forecast	Year End	Partial	Yes	No	Yes	Yes
Entergy New Orleans LLC		Louisiana-NOCC	Gas	Yes	Partially Forecast	Year End	No	Yes	No	Yes	No	
Entergy Louisiana LLC		Louisiana	Electric	Yes	Historical	Average	Partial	Yes	No	Yes	Yes	
Entergy Louisiana LLC		Louisiana	Gas	Yes	Historical	Average	Partial	Yes	No	Yes	Yes	
Entergy Mississippi LLC		Mississippi	Electric	Yes	Fully Forecast	Average	Partial	Yes	No	Yes	No	
Entergy Texas Inc.		Texas	Electric	Yes	Historical	Year End	No	No	No	No	Yes	
Eversource, Inc.	Eversource Kansas Central Inc	Kansas	Electric	Yes	Historical	Year End	Partial	No	No	Yes	No	
	Eversource Metro Inc.	Kansas	Electric	Yes	Historical	Year End	No	No	No	No	Yes	
	Eversource Metro Inc	Missouri	Electric	Yes - Sharing Band	Historical	Year End	Partial	No	No	Yes	Yes	
IDACORP, Inc.	Eversource Missouri West Inc.	Missouri	Electric	Yes - Sharing Band	Historical	Year End	Partial	No	No	Yes	Yes	
	Idaho Power Co.	Idaho	Electric	Yes - Sharing Band	Partially Forecast	Year End	Full	No	No	Yes	No	
NextEra Energy, Inc.	Idaho Power Co.	Oregon	Electric	Yes - Sharing Band	Partially Forecast	Average	No	No	No	No	No	
	Florida Power & Light Co.	Florida	Electric	Yes	Fully Forecast	Average	No	No	No	No	Yes	
NorthWestern Corporation	Gulf Power Co.	Florida	Electric	Yes	Fully Forecast	Average	No	No	No	Average	Yes	
	Pivotal Utility Holdings Inc.	Florida	Gas	Yes	Fully Forecast	Average	No	No	No	No	Yes	
	Lone Star Transmission LLC	Texas	Electric	N/A	Historical	Year End	No	No	No	No	Yes	
	NorthWestern Corporation	Montana	Electric	Yes - Sharing Band	Historical	Average	Partial	No	No	Yes	No	
	NorthWestern Corporation	Montana	Gas	Yes	Historical	Average	No	No	No	No	No	
	NorthWestern Corporation	Nebraska	Gas	Yes	Historical	Year End	No	No	No	No	No	
	NorthWestern Corporation	South Dakota	Electric	Yes	Historical	Average	No	No	No	No	No	
NorthWestern Corporation	South Dakota	Gas	Yes	Historical	Average	No	No	No	No	No		

Otter Tail Corporation	Otter Tail Power Co.	Minnesota	Electric	Yes	Fully Forecast	Average	No	No	No	No	No	No
	Otter Tail Power Co.	North Dakota	Electric	Yes	Fully Forecast	Average	No	No	No	No	No	Yes
Portland General Electric Company Southern Company	Otter Tail Power Co.	South Dakota	Electric	Yes	Historical	Average	No	No	No	No	No	Yes
	Portland General Electric Co.	Oregon	Electric	Yes - Sharing Band	Fully Forecast	Year End	Partial	No	No	No	Yes	Yes
	Alabama Power Co.	Alabama	Electric	Yes	Fully Forecast	Average	No	Yes	No	Yes	Yes	Yes
	Georgia Power Co.	Georgia	Electric	Yes	Fully Forecast	Average	No	Yes	No	Yes	Yes	Yes
	Atlanta Gas & Light Co.	Georgia	Gas	N/A	Fully Forecast	Average	No	Yes	Yes	Yes	Yes	Yes
	Northern Illinois Gas Co.	Illinois	Gas	Yes	Fully Forecast	Average	Partial	No	No	Yes	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	Yes	Fully Forecast	Year End	Partial	Yes	No	Yes	No	No
	Chattanooga Gas Co.	Tennessee	Gas	Yes	Fully Forecast	Average	Partial	Yes	No	Yes	No	No
	Virginia Natural Gas Inc.	Virginia	Gas	Yes	Historical	Average	Partial	No	No	Yes	Yes	Yes
	Public Service Co. of Colorado	Colorado	Electric	Yes	Historical	Average	Partial	No	No	Yes	Yes	Yes
	Public Service Co. of Colorado	Colorado	Gas	Yes	Historical	Year End	Partial	No	No	Yes	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	Yes	Fully Forecast	Average	Partial	Yes	No	Yes	No	No
	Northern States Power Co.-Minnesota	Minnesota	Gas	Yes	Fully Forecast	Average	No	No	No	No	Yes	Yes
	Southwestern Public Service Co.	New Mexico	Electric	Yes	Historical	Year End	No	No	No	No	No	No
	Northern States Power Co.-Minnesota	North Dakota	Electric	Yes	Fully Forecast	Average	No	No	No	Yes	No	Yes
Northern States Power Co.-Minnesota	North Dakota	Gas	Yes	Fully Forecast	Average	No	No	Yes	Yes	No	No	
Northern States Power Co.-Minnesota	South Dakota	Electric	Yes	Historical	Average	Partial	No	No	Yes	Yes	Yes	
Southwestern Public Service Co.	Texas	Electric	Yes	Historical	Year End	No	No	No	No	No	Yes	
Northern States Power Co.-Wisconsin	Wisconsin	Electric	Yes	Fully Forecast	Average	No	No	No	No	No	No	
Northern States Power Co.-Wisconsin	Wisconsin	Gas	Yes	Fully Forecast	Average	No	No	No	No	No	No	

													Revenue Decoupling	Formula-based rates	SFV Rates Design	Non-Volumetric Rate Design	CCRM
Proxy Group Average	Yes	68	Fully Forecast	35	Year End	38	Full	5	Yes	15	Yes	3	Yes	47	Yes	44	
	No	0	Partially Forecast	7	Average	46	Partial	36	No	69	No	81	No	37	No	40	
	N/A	6	Historical	42			No	43									
	Yes-Sharing Band	10															
	Yes/N/A	88.10%	Forecast	50.00%	Year End	45.24%	RDM	48.81%	Yes	17.86%	Yes	3.57%	Yes	55.95%	CCRM	52.38%	

PacifiCorp	PacifiCorp [8]	Oregon	Electric	Yes-Sharing Band	Fully Forecast	Average	No	No	No	No	No	No	No	No	Yes
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Notes:  
[1] Data provided by S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019.  
[2] Sources: Regulatory Research Associates, effective as of September 30, 2021  
[3] Sources: Regulatory Research Associates, effective as of September 30, 2021  
[4] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit. NWE Electric MT - Company 2020 Form 10-K. PSCO Electric CO and SO TN - S&P Global Market Intelligence.  
[5] Sources: Company Form 10-K, Company Tariffs, S&P Global Market Intelligence  
[6] Sources: Company Form 10-K, Company Tariffs, S&P Global Market Intelligence  
[7] Equals IF( AND( [3]=No, [4]=No, [5]=No), No, Yes)  
[8] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit.



Docket No. UE 399  
Exhibit PAC/311  
Witness: Ann E. Bulkley

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Ann E. Bulkley  
Capital Structure Analysis**

**March 2022**

CAPITAL STRUCTURE ANALYSIS

Proxy Group Company	Ticker	Median of Most Recent 8 Quarters			Total Capitalization
		Common Equity Ratio	Preferred Equity Ratio	Long-Term Debt Ratio	
ALLETE, Inc.	ALE	56.86%	0.00%	43.14%	100.00%
Alliant Energy Corporation	LNT	51.58%	1.67%	46.75%	100.00%
Ameren Corporation	AEE	52.60%	0.76%	46.65%	100.00%
American Electric Power Company, Inc.	AEP	48.27%	0.00%	51.73%	100.00%
Avista Corporation	AVA	51.08%	0.00%	48.92%	100.00%
CMS Energy Corporation	CMS	51.22%	0.22%	48.56%	100.00%
Duke Energy Corporation	DUK	52.81%	0.00%	47.19%	100.00%
Entergy Corporation	ETR	46.85%	0.11%	53.04%	100.00%
Evergy, Inc.	EVRG	59.61%	0.00%	40.39%	100.00%
IDACORP, Inc.	IDA	53.86%	0.28%	45.86%	100.00%
NextEra Energy, Inc.	NEE	61.11%	0.00%	38.89%	100.00%
NorthWestern Corporation	NWE	47.43%	0.00%	52.57%	100.00%
Otter Tail Corporation	OTTR	53.13%	0.00%	46.87%	100.00%
Portland General Electric Company	POR	47.81%	0.00%	52.19%	100.00%
The Southern Company	SO	54.23%	0.58%	45.19%	100.00%
Xcel Energy Inc.	XEL	54.04%	0.00%	45.96%	100.00%
	Median	52.71%	0.00%	46.81%	
	Maximum	61.11%	1.67%	53.04%	
	Minimum	46.85%	0.00%	38.89%	

Notes:

[1] Ratios are weighted by actual common capital, preferred capital, and long-term debt of the operating subsidiaries.

[2] Electric operating subsidiaries with data listed as N/A from S&P Capital IQ Pro have been excluded from the analysis.

Docket No. UE 399  
Exhibit PAC/400  
Witness: Michael G. Wilding

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Direct Testimony of Michael G. Wilding**

**March 2022**

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**ATTACHED EXHIBIT**

Exhibit PAC/401—Proposed Transition Adjustment Mechanism Guidelines

1                                   **I. INTRODUCTION AND QUALIFICATIONS**

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

4   A. My name is Michael G. Wilding. My business address is 825 NE Multnomah Street,  
5   Suite 600, Portland, Oregon 97232. My title is Vice President, Energy Supply  
6   Management.

7   **Q. Briefly describe your education and business experience.**

8   A. I received a Master of Accounting from Weber State University and a Bachelor of  
9   Science degree in accounting from Utah State University. As Vice President, Energy  
10   Supply Management (ESM), my responsibilities include directing PacifiCorp's front  
11   office organization in commercial and trading activities. ESM is responsible for  
12   commercially managing PacifiCorp's diverse generation portfolio. This includes the  
13   electric and natural gas hedging, term and day-ahead trading, real-time trading and  
14   system balancing. Prior to assuming my current position in February 2021, I worked  
15   on various regulatory projects including general rate cases, the multi-state process  
16   (MSP), and net power cost (NPC) filings. I have been employed by PacifiCorp since  
17   2014.

18   **Q. Have you testified in previous regulatory proceedings?**

19   A. Yes. I have filed testimony in proceedings before the Public Utility Commission of  
20   Oregon (Commission), and the public utility commissions in California, Idaho, Utah,  
21   Washington, and Wyoming.

1 **II. PURPOSE OF TESTIMONY**

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

3 A. My testimony addresses the persistent under-recovery of net power costs and  
4 proposes two modest changes to the mechanisms through which the Company has the  
5 opportunity to recover its NPC. First, I propose a rate-year update to the transition  
6 adjustment mechanism (TAM) and the inclusion of more accurate hydrological  
7 information. Second, I propose certain modifications to the power cost adjustment  
8 mechanism (PCAM).

9 **III. NPC BACKGROUND**

10 **Q. Please describe how PacifiCorp recovers its Oregon-allocated NPC.**

11 A. In Oregon, PacifiCorp forecasts a level of NPC for the following calendar year (test  
12 year) through the TAM. PacifiCorp uses its Aurora model to forecast NPC for the test  
13 year. This forecast level of NPC is recovered through Schedule 201 during the test -  
14 year. In the year following the test year, PacifiCorp files a PCAM, which is a  
15 mechanism that allows for recovery or return of un-forecasted deviations in NPC.  
16 PacifiCorp has never triggered a rate change through the PCAM.

17 **Q. Why are NPC reset annually?**

18 A. In approving annual power cost updates through the TAM, the Commission has  
19 recognized that “it is important to update the forecast of power costs included in rates  
20 to account for new information, *e.g.*, on expected market prices for electricity and  
21 natural gas, and for new...purchase power contracts” and that “[i]f the forecast is not  
22 updated each year, then [the utility] will be exposed to more than normal business

1 risk.”<sup>1</sup> NPC can vary significantly year-to-year for a variety of reasons, including  
2 changes to loads, fuel costs, market prices, and renewable resource availability. This  
3 variability makes it difficult to accurately forecast NPC for ratemaking purposes.

4 **Q. Please briefly describe the TAM.**

5 A. The purpose of the TAM is to capture costs associated with direct access and prevent  
6 unwarranted cost shifting between cost-of-service customers and customers that elect  
7 direct access service.<sup>2</sup> Significantly, the TAM also sets PacifiCorp’s Oregon-  
8 allocated NPC for the upcoming year.<sup>3</sup> The direct access transition adjustments are  
9 calculated by comparing the value of energy used to serve direct access loads with the  
10 cost-of-service rate under the customers’ specific energy-only tariff. The Commission  
11 adopted an annual NPC update to ensure that both the value of freed-up energy and  
12 the cost-of-service rate are calculated for the same period using the same data. The  
13 Commission has articulated the importance of accurate NPC modeling in the TAM:

14 PacifiCorp’s TAM is an annual filing in which PacifiCorp projects  
15 the amount of [NPC] to be reflected in customer rates for the  
16 following year, as well as to set transition charges for customers  
17 electing to move to direct access. The TAM effectively removes  
18 regulatory lag for the company because the forecasts are used to  
19 adjust rates. For that reason, the accuracy of the forecasts is of  
20 significant importance to setting fair just and reasonable rates. Our  
21 goal, therefore, is to achieve an accurate forecast of PacifiCorp’s  
22 [NPC] for the upcoming year.<sup>4</sup>

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<sup>1</sup> *In the matter of Portland General Elec. Co., Request for a General Rate Revision*, et al, Docket Nos. UE 180, UE 181, and UE 184, Order No. 07-015 at 18 (Jan. 12, 2007).

<sup>2</sup> *In the matter of Pacific Power & Light Company (dba PacifiCorp) Request for a General Rate Increase in the Company’s Oregon Annual Revenues*, Docket No. UE 170, Order No. 05-1050 at 21 (Sept. 28, 2005).

<sup>3</sup> *In the matter of PacifiCorp, dba Pacific Power 2008 Transition Adjustment Mechanism*, Docket No. UE 191, Order No. 07-446 at 2 (Oct. 17, 2007).

<sup>4</sup> *In the matter of PacifiCorp, dba Pacific Power 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 2-3 (Dec. 20, 2016).

1 **Q. Please briefly describe PacifiCorp’s PCAM authorized by the Commission.**

2 A. Commission Order 12-493 approved a PCAM to allow PacifiCorp to recover the  
3 difference between actual PCAM costs incurred to serve customers and the base  
4 PCAM costs established in PacifiCorp’s annual TAM filing.<sup>5</sup> PCAM costs include  
5 NPC, other revenues, and federal production tax credits (PTC). As the Commission  
6 observed when it adopted a PCAM for Portland General Electric Company, the  
7 PCAM has been designed so that the utility “will bear normal business risk associated  
8 with actual power costs varying from forecast.”<sup>6</sup>

9 **Q. Please describe the relationship of the TAM and PCAM.**

10 A. Each year the PCAM compares the NPC collected from Oregon customers in rates set  
11 in the TAM to the actual Oregon-allocated NPC. The PCAM variance, however, is  
12 subject to an asymmetrical deadband between a \$30 million under-collection and a  
13 \$15 million over-collection, a symmetrical sharing band where the Company absorbs  
14 10 percent of the variance outside the deadband, and finally a symmetrical earnings  
15 test where the collection or refund of a PCAM variance is limited to amounts that will  
16 bring PacifiCorp to within 100 basis points of the Company’s authorized return on  
17 equity (ROE). Additionally, the amortization of deferred amounts is capped at  
18 six percent of the revenue for the preceding calendar year.

19 **IV. RATE-YEAR UPDATE FOR THE TAM**

20 **Q. Please describe the change PacifiCorp is proposing in the TAM.**

21 A. PacifiCorp is proposing a limited update to take place during the rate year. This

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<sup>5</sup> *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Case*, Docket No. UE 246, Order No. 12-493 (Dec. 20, 2012).

<sup>6</sup> Order No. 07-015 at 17-19.



1 update would update to the latest official forward price curve, include the latest short-  
2 term purchases and sales, and the most recent hydrologic forecast for the test-year.

3 **Q. How will the Rate-Year Update work?**

4 A. PacifiCorp will update Schedule 201 rates during the rate year with a filing that  
5 occurs on March 1. Similar to the final TAM filing, PacifiCorp will file the  
6 information, workpapers, and tariff sheets supporting the Rate-Year Update with a  
7 NPC forecast based on the updated information outlined above. After Staff and  
8 interested parties have sufficient time to review, the Commission would approve the  
9 update, with a rate effective date of April 1.

10 **Q. Why is PacifiCorp proposing the Rate-Year Update?**

11 A. The purpose of the Rate-Year Update is to update NPC to incorporate the latest  
12 information and costs that are necessary to meet PacifiCorp's resource adequacy  
13 requirements for the Western Power Pool's (WPP) Western Resource Adequacy  
14 Program (WRAP). It also notable that WPP WRAP program is also currently  
15 proposed by Commission Staff as a standard in Oregon's resource adequacy  
16 program.<sup>7</sup> By February 28 of each year, PacifiCorp will have completed the process  
17 to cure any issues with capacity deficiencies for the summer of the rate year for the  
18 WRAP. Additionally, PacifiCorp will be close to the March 31 submittal date for the  
19 winter period in the WRAP which begins on November 1 of the rate year. Therefore,  
20 the Rate-Year Update will allow PacifiCorp to update NPC for any new short-term  
21 contracts that were necessary to meet WRAP resource adequacy requirements for the  
22 summer, and PacifiCorp will also have good information on meeting the winter

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<sup>7</sup> *Investigation into Resource Adequacy in the State*, Docket No. UM 2143, Staff Straw Proposal (Oct. 15, 2021).

1 resource adequacy requirements as well. Additionally, this update will occur in  
2 spring, which means the NPC forecast will allow the incorporation of the latest  
3 forward prices and hydrologic conditions.

4 **Q. Is PacifiCorp proposing to update Direct Access Rates in the Rate-Year Update?**

5 A. No, PacifiCorp is not proposing changes to the Direct Access Rates that would occur  
6 outside the Direct Access pricing period. The purpose of the Rate-Year Update is to  
7 capture the acquisition of any resources or transactions to meet the Company's  
8 resource adequacy requirements and set the TAM rates as accurately as possible. It is  
9 PacifiCorp's understanding that Electric Service Suppliers will be subject to separate  
10 resource adequacy requirements under the latest proposals in the Commission's  
11 resource adequacy proceedings.

12 **V. CHANGES TO THE TAM GUIDELINES**

13 **Q. Will the Rate-Year Update require changes to the TAM guidelines?**

14 A. Yes. The TAM guidelines will need to be updated to allow for a Rate-Year Update  
15 and to include using forecast hydro generation in place of the normalized hydro  
16 generation that is used today for the Lewis River hydro project.

17 **Q. What other changes is PacifiCorp proposing to the TAM guidelines?**

18 A. To increase the accuracy of hydro generation in the TAM, PacifiCorp is proposing to  
19 replace normalized forecast data with more accurate, rate year specific hydrologic  
20 information as an input to calculate hydro generation in the rebuttal, indicative, final,  
21 and Rate-Year Updates for the TAM. Hydro generation has a significant impact on  
22 PacifiCorp NPC and by incorporating rate year hydrologic data, like the official

1 forward price curve, market transactions and updates, PacifiCorp will be providing a  
2 more accurate NPC forecast.

3 **Q. How Does PacifiCorp currently develop its normalized hydrological forecast?**

4 A. PacifiCorp develops its hydrological forecast in a three-step process. The first step  
5 estimates normalized annual flow forecast for the Merwin plant. Historical annual  
6 median flow is calculated based on the flow data available since 1929 and used as the  
7 normalized annual flow forecast for the Merwin plant. The second step estimates  
8 normalized monthly flow forecast for the Merwin, Yale and Swift plants. Monthly  
9 median flows for the Merwin plant are calculated based on the 10-year monthly flow  
10 data. Their relative sizes are used to subdivide the normalized annual flow forecast  
11 into the normalized monthly flow forecasts. For each month, the relative flow for the  
12 Yale and Swift plants to the Merwin plant is also estimated, and used to determine the  
13 normalized monthly flow forecast for the Yale and Swift plants. The third step  
14 estimates normalized weekly generation forecasts. The Vista DSS model, which is  
15 set up for the Lewis River project, is run using the normalized monthly flow forecast  
16 as one of the inputs, and produces normalized weekly generation forecasts. Past  
17 TAM filings have used these normalized forecasts.

18 **Q. Is PacifiCorp proposing to use an independent third-party source for the**  
19 **forecast hydrologic information?**

20 A. Yes, for the Lewis River hydro project, PacifiCorp is proposing to use information  
21 from the Northwest River Forecast Center (NWRFC), and from the National Oceanic  
22 and Atmospheric Administration (NOAA), which produces a rolling 12-month  
23 hydrological forecast. This is the same source of hydrologic information that is used

1 by the Idaho Power Company for its March update in their annual power cost  
2 update.<sup>8</sup>

3 **Q. What is the specific hydrologic information that will be used?**

4 A. In line with current practice, the Company will use historical monthly streamflow  
5 data, estimated for each key project site, to develop its forecasts based on normalized  
6 data. For the Final Update in November, the 12-month Monthly Water Supply  
7 Volume Forecasts published by the NWRFC of the NOAA will be used to overwrite  
8 the January to November forecast values. This updated forecast will provide more  
9 exact streamflow data than the normalized estimates used in the initial forecast in the  
10 rate year. Since the December period of the normalized data is not updated in this  
11 forecast, PacifiCorp will use the Seasonal Outlooks for Temperature and Precipitation  
12 published by the Climate Prediction Center of NOAA for December if its warranted.  
13 For the Rate-Year Update in February, the updated data will be reviewed and  
14 compared with Monthly Water Supply Volume Forecast by NWRFC, Stream Forecast  
15 from the Natural Resources Conservation Service of the United States Department of  
16 Agriculture as well as Seasonal Hydro Forecast provided by Upstream Tech, the river  
17 forecast company that PacifiCorp contracts to support the Lewis River project, in  
18 order to ensure we are using the most current hydrological forecasts available.

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<sup>8</sup> *In the Matter of Idaho Power Company, Application for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon*, Docket No. UE 195, Order No. 08-238, Appendix A at 6 (Apr. 28, 2008).

1 **Q. Which hydro resources will use forecasted hydrological forecasts as input the**  
2 **hydro generation modeling?**

3 The Lewis River hydro generation resources (Swift, Yale and Merwin) will utilize  
4 forecasted hydrology as an input to hydro generation modeling.

5 **Q. How will this information be incorporated in the Aurora forecast?**

6 A. Currently, hydro generation data is pre-processed outside of the Aurora model  
7 utilizing the normalized forecast. Hydro generation is input into Aurora as a fixed  
8 generation schedule. To accommodate the switch from the normalized forecast for  
9 January to November to the proposed rate year rolling forecast data, the Aurora input  
10 files for the hydro generation would be updated with a new generation forecast  
11 utilizing forecasted hydrology as part of the Company's standard input update process  
12 for the Final Update.

13 **Q. How will integration of this data lead to a more accurate NPC forecast in the**  
14 **TAM?**

15 A. Hydrological conditions and operational requirements change over time, so using the  
16 most current hydrologic data and forecasts available rather than normalized data  
17 accumulated over many years is expected to produce more relevant and accurate  
18 generation forecasts for the given rate year.

19 **Q. Is the hydro forecast in the spring better than ones in the winter?**

20 A. Yes, snow accumulation and the melt processes play a key role in the Lewis basin  
21 hydrology. Snowpack accumulated in the winter is the major source of water for the  
22 surface runoff during the snowmelt season and the groundwater flow during the dry  
23 season. Historically, snowpack around the Lewis basin often peaks around early

1 April. Therefore, hydrologic information available in the spring, including snowpack  
 2 conditions and spring weather forecast, could provide valuable information to  
 3 improve the hydro forecast for the Lewis basin in the snowmelt and following dry  
 4 seasons. This means that the hydrologic forecast that is included in the Rate-Year  
 5 Update will provide the most accurate information for the TAM.

6 **Q. How will the hydrologic information be incorporated into the various updates?**

7 A. Based on the availability of the data, the initial TAM filing will still use normalized  
 8 data, however, the subsequent filings use various update forecasts. Using the 2024  
 9 TAM as an example, the table below provides a summary of how the hydro  
 10 information will be incorporated into the various updates.

11 **Table 1**

2024 TAM Filing	Month	Forecast Hydro Period	Normalized Hydro Period
Initial	April 2023	N/A	Jan-Dec 2024
Rebuttal	July 2023	Jan-May 2024	Jun – Dec 2024
Final Update	November 2023	Jan-Sept 2024	Oct-Dec 2024
Rate-Year Update	March 2024	Jan-Dec 2024	N/A

12 **Q. Is PacifiCorp proposing other changes to the TAM Guidelines?**

13 A. Yes, as part of this general rate case, PacifiCorp is taking the opportunity to  
 14 incorporate the elements from various TAM Orders into the TAM Guidelines to allow  
 15 for the codification of all the changes that have occurred since the TAM Guidelines  
 16 were originally adopted. In Exhibit PAC/401, PacifiCorp has provided a draft of

1 these revised TAM Guidelines that detail the changes that have been proposed and the  
2 source of those proposed changes.

3 **VI. PCAM CHANGES**

4 **Q. What are the changes PacifiCorp is proposing to the PCAM?**

5 A. PacifiCorp is proposing three changes to the structure of the PCAM:

- 6 1. PacifiCorp is proposing to adjust the deadbands to be symmetrical by moving the  
7 upper deadband from \$30 million to \$15 million;  
8 2. Setting the earnings test at PacifiCorp's authorized ROE; and  
9 3. PacifiCorp may propose that the NPC costs of certain months be recovered  
10 outside the deadbands, sharing bands, and earnings test.

11 **Q. The Commission denied PacifiCorp's proposed changes to the PCAM in  
12 PacifiCorp's last general rate case. Why is PacifiCorp again proposing changes  
13 to the PCAM?**

14 A. When the Commission declined to adopt PacifiCorp's proposed changes to the  
15 PCAM mechanism, it was noted that "PacifiCorp has not demonstrated a fundamental  
16 change in the risk balance between customers and the company that occurs with its  
17 power costs."<sup>9</sup> During the last general rate case, there was a lot of time spent on  
18 PacifiCorp's modeling of NPC and the systematic under-recovery of NPC.  
19 Admittedly, the Company did not address the "fundamental change in the risk balance  
20 between customers and the company." However, the loss of dispatchable generation  
21 across the West and the consequential change in the market has fundamentally altered  
22 the risk balance on power costs. PacifiCorp is proposing these changes as consistent

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<sup>9</sup> *In the Matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 129 (Dec. 18, 2020).

1 with the purpose of the PCAM, which is to allow adjustment for “unusual events and  
2 [to] capture power cost variances that exceed those considered normal business risk  
3 for the utility.”<sup>10</sup> I intend to address the risk balance and show that it has indeed  
4 shifted and warrants small but fair changes to the PCAM.

5 **Q. At a high level, how have the operating and market environments the Company**  
6 **is operating in changed over the past decade?**

7 A. While there have been likely too many changes impacting PacifiCorp and the entire  
8 utility sector to mention them all, some of the key changes are related to resource  
9 mix, supply and demand, macroeconomic factors, technology adoption and change,  
10 environmental policy changes, as well as climate change related impacts and  
11 associated mitigation strategies. Additionally, the Western Energy Imbalance Market  
12 (EIM), operated by the California Independent System Operator (CAISO) was  
13 launched in 2014 and has seen extensive growth in members and benefits. Similarly,  
14 electrification of transportation and building has not only become mainstream but is  
15 part of the Company’s resource strategy. The Company’s 2021 Integrated Resource  
16 Plan (IRP) provides a detailed illustration of the above mentioned and other factors.  
17 Regional resource adequacy assessments highlight that there are resource adequacy  
18 risks through the mid-2020s. The addition of variable energy resources replacing  
19 traditional “baseload” resources may act to tighten market supply. There are risks to  
20 whether the market is available to purchase power and risks to the price will impact  
21 NPC for customers. Energy policies in the western states have been enacted to lower  
22 emissions. Climate change is impacting summer and winter loads forecasts. It is also

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<sup>10</sup> *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Case*, Docket No. UE 246, Order No. 12-493 at 13 (Dec. 20, 2012).

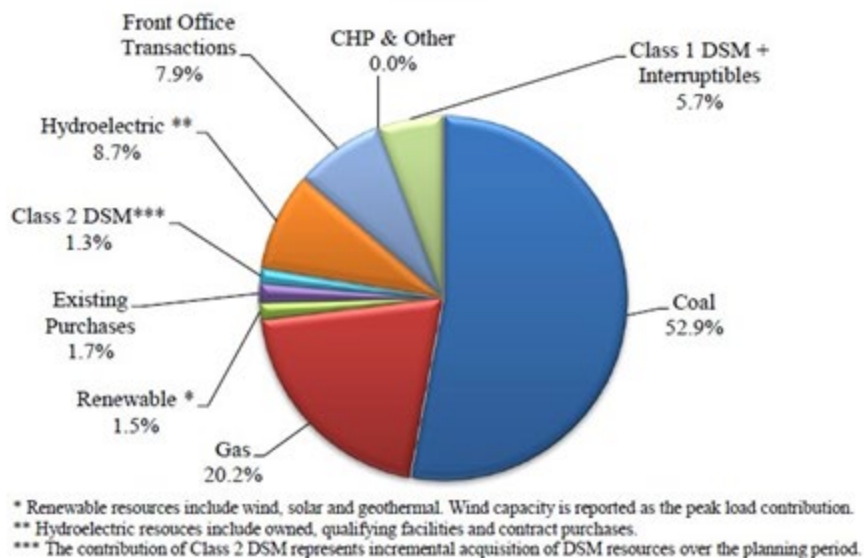


1 impacting renewable solar and wind resources generation, natural gas generation, as  
2 well as hydro generation to serve loads.

3 **Q. How has PacifiCorp's resource mix changed since 2013?**

4 A. In 2013, more than 70 percent of the Company's capacity mix was made up of  
5 dispatchable thermal resources. After adding in, hydro, front-office transactions, and  
6 long-term purchases more than 90 percent of the Company's capacity mix was from  
7 sources with firm energy delivery schedules. In contrast, in 2022, only 49 percent of  
8 the Company's capacity mix is from dispatchable thermal resources, and 32 percent is  
9 from renewable resources. While renewable resources are cost-effective for  
10 customers and carry many benefits, they do not have firm energy delivery schedules.  
11 Figure 1 and Figure 2 below presents the Company's capacity mix in 2013 and  
12 capacity mix forecast from the 2021 IRP.

13 **Figure 1: PacifiCorp's 2013 Capacity Mix<sup>11</sup>**

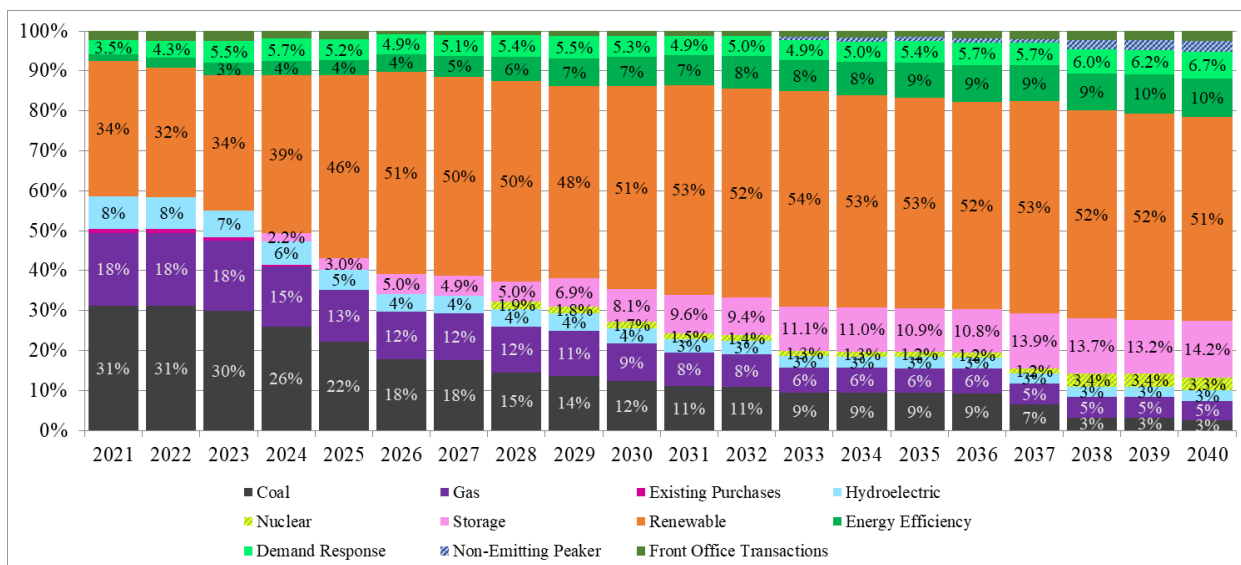


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<sup>11</sup> *In the matter of PacifiCorp, dba Pacific Power, 2013 Integrated Resource Plan*, Docket No. LC 57, PacifiCorp's 2013 Integrated Resource Plan at 229 (Apr. 30, 2013).

1

**Figure 2: PacifiCorp 2021 Capacity Mix<sup>12</sup>**



2 **Q. Have the changes in the Company’s resource portfolio affected the risk balance**  
 3 **between customers and the Company with respect to power costs? Please**  
 4 **explain.**

5 **A.** Yes. There is substantially more uncertainty in 2022 as PacifiCorp relies on cost-  
 6 effective variable energy resources. Additionally, PacifiCorp has substantially less  
 7 control over power costs than it did in 2013.

8 In 2013, a capacity mix with a firm energy delivery schedule meant there was  
 9 less uncertainty in power costs. As coal made up 52 percent of the capacity mix a  
 10 significant portion of power costs could be contracted through coal supply  
 11 agreements thus protecting the Company and customers to changes in market prices.  
 12 Additionally, significant amounts of generation output were not dependent upon

<sup>12</sup> In the matter of PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan, Docket No. LC 77, PacifiCorp’s 2021 Integrated Resource Plan at 305 (Sept. 1, 2021).

1 weather. The greatest uncertainty of the Company's generation was the risk of an  
2 unplanned outage.

3 In 2022, this is no longer the case. Variable energy resources such as wind  
4 and solar provide several benefits to customers, notably low-cost power with  
5 environmental benefits, but they present unique complexities and challenges to  
6 hedging, balancing, and operation of the system. Unlike coal, natural gas, and certain  
7 hydroelectric resources that can be dispatched to follow changes in customer  
8 demands, these resources are non-dispatchable. They generate power intermittently  
9 when the wind blows or the sun shines.

10 The growing penetration of renewable energy has created significant hourly  
11 volatility to the supply of energy. This, along with the retirement of firm thermal  
12 generation capacity, has resulted in wide swings in the value of energy across a given  
13 day. Output from variable energy resources (VERS) cannot be controlled, in contrast  
14 to a traditional resource mix of dispatchable resources that could be controlled and  
15 where variability of those resources largely stemmed from outages. The traditional  
16 resource mix lent itself better to dead bands and sharing bands as the Company has  
17 some ability to prevent unplanned outages, whereas the Company has no control over  
18 the wind or sun to fuel variable resource generation.

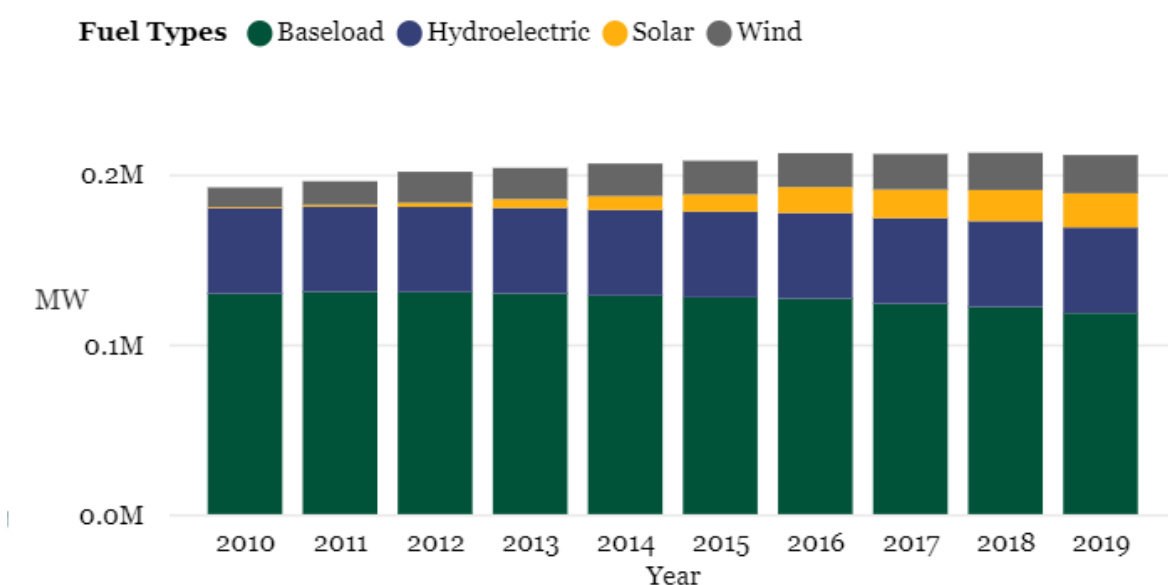
19 Electric utilities across the west, including the Company, have and will  
20 continue to acquire significant additional variable energy resources, which increase  
21 the challenge of hedging and balancing the system. These factors have increased the  
22 complexity and difficulty and costs of balancing the system. Customers enjoy the  
23 benefits of these low-cost and zero emission resources, but absent changes to the

1 PCAM, do not adequately share the costs the Company must incur to respond to the  
2 variable nature of these resources.

3 **Q. Has the western United States seen a similar shift in the greater resource mix?**

4 Yes. As illustrated in Figure 3 below, even at the greater Western Energy  
5 Coordinating Council (WECC)-wide level, the resource capacity mix between 2010  
6 and 2019 demonstrates growth in solar and wind along with a reduction in base load  
7 capacity (defined by WECC to include coal, gas, geothermal and nuclear).

8 **Figure 3: 2010–2019 Capacity by State<sup>13</sup>**

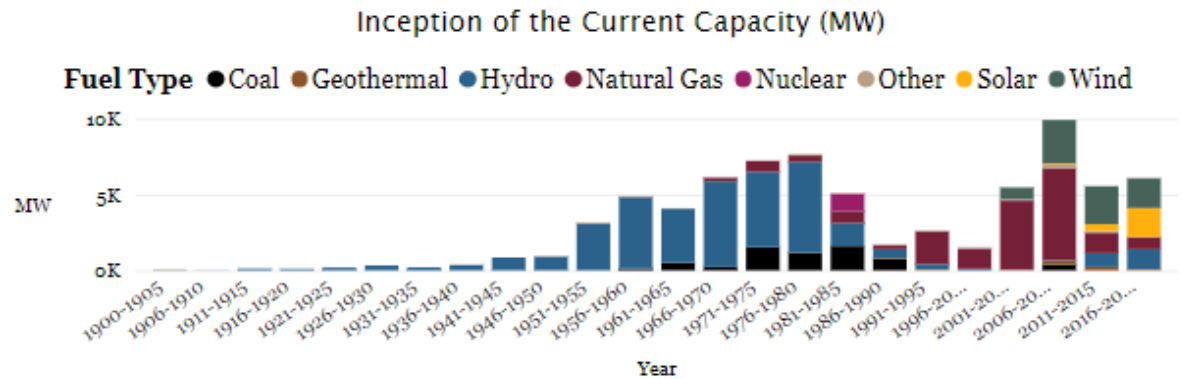


9 Figure 4 and Figure 5 below illustrate the historical change in regional capacity for  
10 the WECC Northwest Region and the WECC’s Rocky Mountain Region, both of  
11 which are relevant to the Company’s resource footprint. While the resource fleet  
12 differs by region, both regions have witnessed significant changes in the makeup of  
13 the regional generation resources.

<sup>13</sup> *Capacity by State, State of the Interconnection*, WESTERN ELECTRICITY COORDINATING COUNCIL, <https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Capacity-by-State.aspx>.

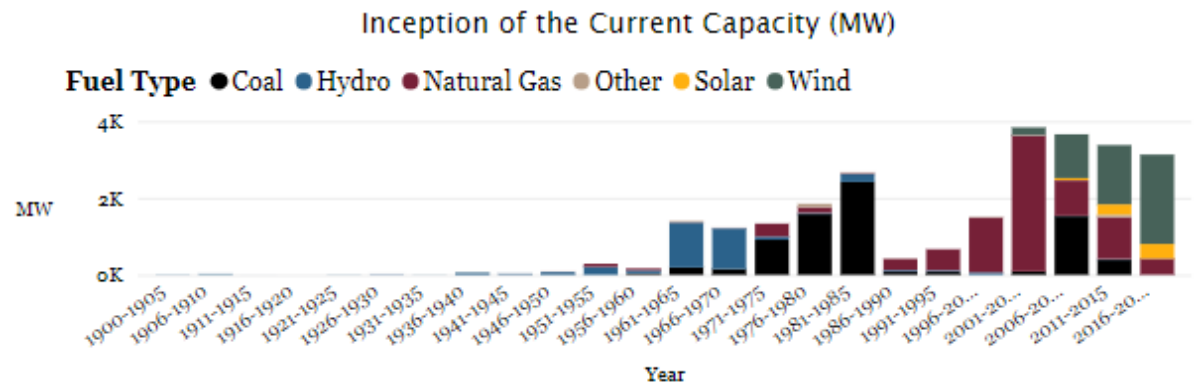
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Figure 4<sup>14</sup>



2

Figure 5<sup>15</sup>



3 **Q. How has the change in the regional resource mix impacted electric and natural**  
 4 **gas markets?**

5 The increasing amounts and relative proportions of non-dispatchable variable energy  
 6 resources have increased the complexity of hedging and balancing activities for the  
 7 entire region. Power and natural gas markets have seen a marked increase in  
 8 volatility of supply and demand and the resulting impact on market transaction prices.

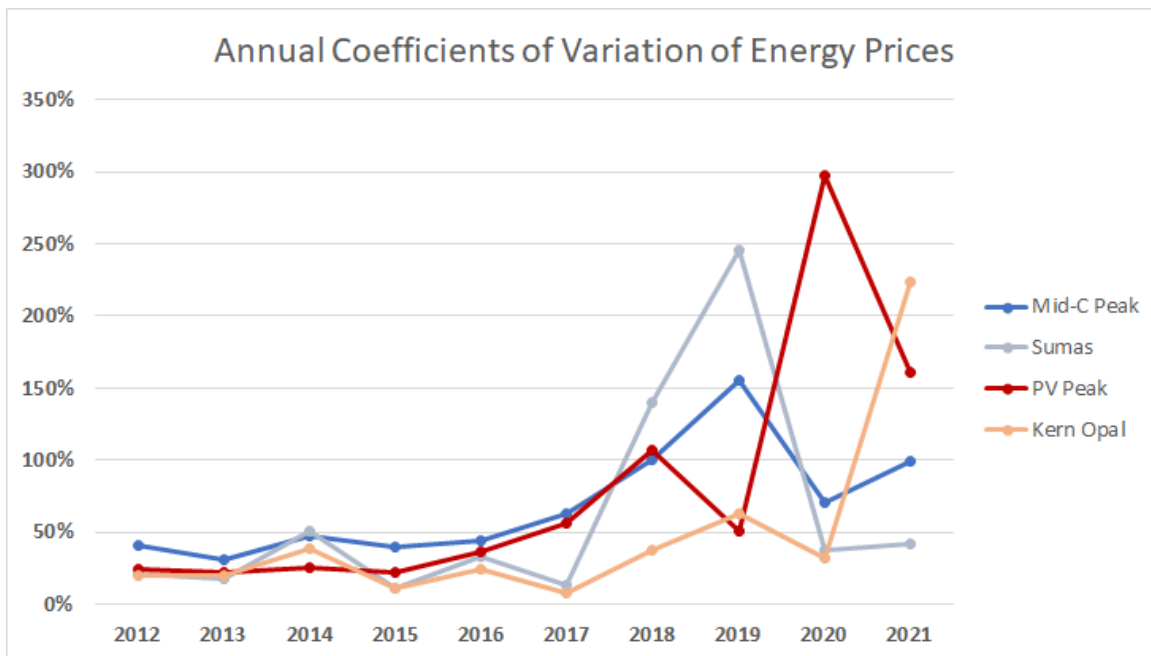
9 Figure 6 shows the annual coefficient of variation of daily spot market prices for the

<sup>14</sup> Capacity, State of the Interconnection, WESTERN ELECTRICITY COORDINATING COUNCIL, <https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Capacity.aspx>.

<sup>15</sup> *Id.*

1 power and gas markets the Company most frequently transacts in. As Figure 6  
2 depicts, there has been a substantial change in volatility across the markets that  
3 PacifiCorp participates in since 2017.

**Figure 6**

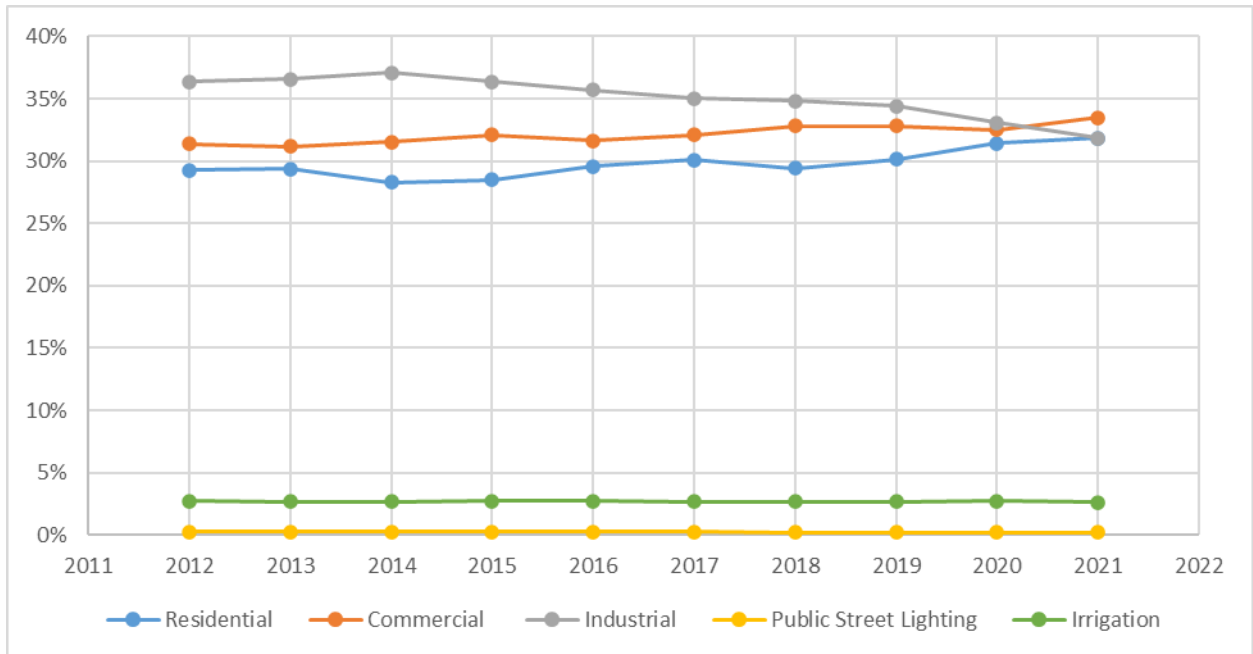


4 **Q. Please summarize the key changes in customer demands from 2012 to 2021.**

5 A. The Company has observed the composition of load served has been changing over  
6 time. Figure 7 presents the composition of loads by class for PacifiCorp's total  
7 system. As illustrated, over the past decade, the proportion of residential and  
8 commercial loads have increased, while the proportion of industrial loads have  
9 declined over time.

1  
2

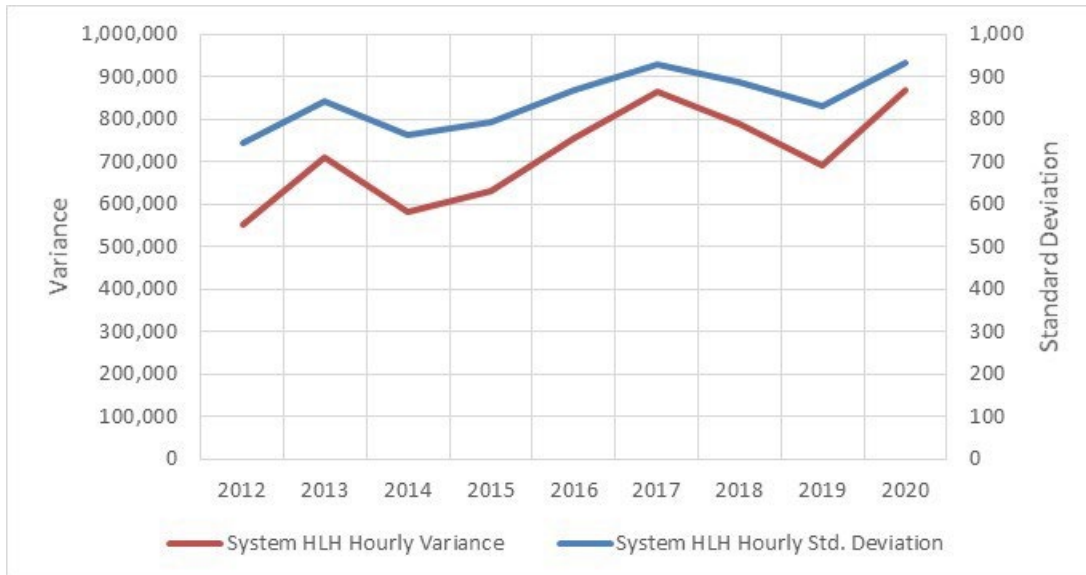
**Figure 7: Actual Retail Sales Class Composition for PacifiCorp's full system  
(2012 – 2021)**



3 Collectively, these factors have resulted in larger load volatility given the lower load  
4 factors of residential and commercial loads. Industrial loads tend to have less  
5 fluctuation throughout the year. Specifically, since 2012, the volatility of the hourly  
6 system load for heavy load hours (HLH), as indicated by the variance and the  
7 standard deviation, show a clear upwards trend (Figure 8).

1  
2

**Figure 8: Total Company Heavy Load Hour Hourly System Load Variability  
(2012 – 2020)**



3 **Q. Why does the change in retail load composition hourly load variability represent**  
4 **a shift in power cost risk balance?**

5 A. It represents another input to the Company's resource management equation that has  
6 shown an increase in variability over the past 10 years. Having loads with greater  
7 volatility results in more expensive hedging costs.

8 **Q. How do the changes in the Company's resource portfolio and changes in**  
9 **customer demands affect the company's ability to forecast power costs?**

10 A. As the certainty of generation and demand forecasts decreases, so does the ability to  
11 accurately forecast actual power costs. The fewer dispatchable resources at a  
12 company's disposal, the less certainty exists around the ultimate cost to serve load.  
13 That is because absent very large-scale energy storage, total costs depend increasingly  
14 on the timing between VERS generation and customer load. Periods of low VERS  
15 generation and high load result in large volumes of power subject to spot market



1 prices. The same applies to periods of high VERS generation and low customer  
2 loads.

3 **Q. How does the Company hedge its power and natural gas price risk?**

4 A. The Company forecasts power and natural gas positions based on all available  
5 information (loads, renewable resources, thermal plant availability, etc.). Natural gas  
6 price risk is hedged primarily with swap contracts. These contracts provide a  
7 financial hedge where the Company pays a fixed price to a counterparty and in return  
8 receives an index settlement price for a predetermined volume of natural gas. The  
9 settlement price becomes known in the final days before the contract month.

10 However, this settlement price may still differ from balancing transaction prices the  
11 Company must engage in on a daily basis for operations.

12 Power is hedged primarily with fixed-price physical “on-peak” and “off-peak”  
13 contracts, typically at the Mid-Columbia or Palo Verde market hubs for the west and  
14 east sides of the system, respectively. An “on-peak” forward purchase or sale results  
15 in the transfer of an equal volume of power for the sixteen “on-peak” hours each  
16 Monday through Saturday excluding holidays. An “off-peak” forward purchase or  
17 sale results in the transfer of an equal volume of power for the eight “off-peak” hours  
18 each Monday through Saturday and all 24 hours of a Sunday or a holiday. These “on-  
19 peak” and “off-peak” products are liquid and readily available. Products of narrower  
20 groupings of hours are not available in sufficient quantity for hedging.

1 **Q. Have the instruments available to the Company to hedge changed materially**  
2 **from 2012 to 2022?**

3 A. No. Despite the increased volatility in size and value of individual hours throughout  
4 the day, power hedges are still purchased or sold in on-peak, and off-peak blocks.

5 **Q. Has the complexity to hedge power costs changed from 2012 to 2022?**

6 A. Yes. As the hourly load and resource balance of the Company's portfolio sees wider  
7 variations in hourly open positions, these instruments are increasingly less effective in  
8 providing flat (balanced load and resource) positions. If traders wish to purchase on-  
9 peak forward hedges to provide price protection for the highest peak hours of a  
10 month, these transactions, with equal volumes across all on-peak hours create  
11 significant additional length in hours other than the highest peak hours. As delivery  
12 nears, this creates additional challenges to balance the system by dispatching  
13 resources down or selling the excess energy in hours with more surplus energy, often  
14 at a substantially lower price than paid for the entire block. Conversely, if traders  
15 purchase a lower quantity to avoid excess length across these hours, this may leave  
16 the highest peak hours short. Purchasing these highest peak hours in the spot market  
17 can be very expensive as supply and demand forces often cause extreme spikes in the  
18 price of power, spikes that have increased in size and frequency as all utilities  
19 struggle with uncontrollable changes in VERS output and increasingly volatile loads.  
20 Lastly, this could cause reliability risk as there is no guarantee that the energy is in  
21 fact available when needed.

1 **Q. How does moving to a symmetrical \$15 million deadband in the PCAM help**  
2 **PacifiCorp to rebalance the risk between customers and the Company in light of**  
3 **the changed conditions described above?**

4 A. This adjustment was inspired by Staff’s testimony on alternative adjustments to the  
5 PCAM from PacifiCorp’s last general rate case, where Staff noted that making the  
6 deadbands symmetrical “would allow customers and shareholders to share costs and  
7 risks.”<sup>16</sup> Staff also suggested reducing the size of the deadbands,<sup>17</sup> which would also  
8 increase the likelihood of adjustments to the mechanism. Incorporating these two  
9 adjustments would help rebalance the risk between the Company and customers by  
10 allowing PacifiCorp a better opportunity to recover the significant deviations from  
11 forecast NPC.

12 **Q. Please explain PacifiCorp’s proposal to set the PCAM earnings test at**  
13 **PacifiCorp’s authorized ROE?**

14 A. Currently, the PCAM earnings test is set at 100 basis points of PacifiCorp’s  
15 authorized ROE. This means that if PacifiCorp’s earned ROE is within plus or minus  
16 100 basis points of the authorized ROE, there will be no recovery from or refund to  
17 customers. PacifiCorp is proposing to change the earnings test so that the 100 basis  
18 point collaris removed, but PacifiCorp’s recovery of costs in the PCAM is capped  
19 when the authorized ROE is reached. Additionally, if PacifiCorp will be providing a  
20 credit to customers under the PCAM, that credit is capped at PacifiCorp’s ROE  
21 instead of being capped at 100 basis points above the ROE.

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<sup>16</sup> *In the Matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Staff/2400, Gibbens/32 (Jul. 24, 2020).

<sup>17</sup> *Id.* at Staff/2400, Gibbens/31.

1 **Q. Does PacifiCorp's proposal still provide a mechanism that is consistent with the**  
2 **purposes identified by the Commission?**

3 A. Yes, by setting the earnings test at PacifiCorp's authorized ROE, and keeping the  
4 deadbands, it still ensures that rate adjustments only occur for significant NPC  
5 variations. Additionally, the earnings test would now prevent the PCAM from  
6 allowing the utility to earn beyond its authorized ROE.

7 **Q. Please explain PacifiCorp's final proposed change to the PCAM.**

8 A. The final adjustment is intended to introduce more flexibility into the PCAM  
9 mechanism. It allows the Company to identify certain specific and unusual months  
10 that resulted in significant costs and therefore a significant deviation from the NPC  
11 baseline forecast for that month. The Company can then propose to recover the costs  
12 of those unusual months through the PCAM mechanism but outside the deadbands,  
13 sharing bands, and earnings test.

14 **Q. How does PacifiCorp propose this change would function in the PCAM**  
15 **mechanism?**

16 A. PacifiCorp would identify a month that resulted in unusual or significant costs that  
17 deviate from the forecast and would propose the recovery of those costs that deviated  
18 from the NPC forecast when the PCAM filing is made on May 15. PacifiCorp would  
19 bear the burden of showing that these costs were appropriate for recovery outside the  
20 deadbands, sharing bands, and earnings test. Stakeholders could then review the  
21 costs and present testimony to the Commission opposing or supporting PacifiCorp's  
22 proposal, and the Commission would then determine whether they are appropriate for  
23 recovery on a case-by-case basis.

1 **Q. Can you provide an example of a significant and unusual month that resulted in**  
2 **a large deviation from baseline net power costs??**

3 A. Yes. On October 9, 2018, the Enbridge natural gas pipeline that transports natural  
4 gas produced in the Western Canadian Sedimentary Basin to consumers in British  
5 Columbia (B.C.) and, through interconnecting pipelines, the Northwestern United  
6 States (U.S.), experienced a massive rupture. The pipeline was brought back into  
7 service in late October 2018, however, at a reduced capacity until testing of the many  
8 segments of the pipeline were completed. Spot natural gas prices at the Sumas B.C.-  
9 U.S. border trading point traded as high as \$159 per million British thermal units on  
10 days of intense demand due to cold weather and reduced natural gas supply in the  
11 first quarter of 2019.

12 The pipeline rupture and reduced operating capacity impacted electricity  
13 prices primarily at the Mid-Columbia power market hub, but also increased electricity  
14 prices and natural gas prices at other trading points where PacifiCorp transacts.  
15 PacifiCorp has one natural gas-fired generator—the Chehalis plant—that is sourced  
16 from the Sumas natural gas hub. Due to the pipeline rupture, and cold weather  
17 impacting B.C. and the Northwest there were times of limited availability of natural  
18 gas flowing to the Sumas gas hub. With the inability to fully utilize the Chehalis  
19 plant in part due to strong natural gas demand from residential and commercial  
20 customers in B.C. due to weather conditions, PacifiCorp was faced with more market  
21 purchases during times of much higher prices at Mid-Columbia which ultimately  
22 increased NPC.

23 In February of 2019, an extreme cold event was forecasted early in the month

1 and combined with limited hydro resources being available in the region significantly  
2 increased power prices. These conditions resulted in a significant deviation from  
3 forecast net power costs in February of 2019. Specifically, there was a \$12.0 million  
4 (Oregon-allocated) deviation from forecasted NPC for that month in the PCAM.<sup>18</sup>

5 **Q. Can you describe how this event is outside the normal business risk associated**  
6 **with NPC?**

7 A This catastrophic event and corresponding rise in natural gas prices was not  
8 forecastable and was completely outside the Company's control. The current  
9 structure of the PCAM inappropriately balances the risk between the customers and  
10 the Company. PacifiCorp's proposal to recover actual NPC outside the restrictions of  
11 the PCAM during aberrant months can help restore the balance.

## 12 VII. EIM AND WRAP FEES

13 **Q. Are there any new fees associated with PacifiCorp's participation in regional**  
14 **organizations that are going to be included in base rates?**

15 A. Yes, PacifiCorp is proposing to include fees related to the EIM Body of State  
16 Regulators (BOSR) and the WPP WRAP in base rates.

17 **Q. Please explain the purpose of the EIM BOSR.**

18 A. The EIM BOSR is a body that addresses the regional nature of the EIM through the  
19 EIM governance process. The purpose of the EIM BOSR is to provide "a forum for  
20 state commissioners to (1) select a voting member of the EIM Governing Body  
21 Nominating Committee, (2) learn about and discuss the EIM and CAISO markets,

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<sup>18</sup> *In the Matter of PacifiCorp d/b/a Pacific Power, 2019 Power Cost Adjustment Mechanism*, Docket No. UE 379, PAC/101, Webb/1 (May 15, 2020).

1 and (3) express a common position in CAISO stakeholder processes or to the EIM  
2 Governing Body on EIM issues.”<sup>19</sup>

3 **Q. Please explain the new fee that is associated with the EIM BOSR?**

4 A. As described by the EIM BOSR, the fee supports the BOSR’s expenses and support  
5 the body’s goal that “consistent, and informed regulator engagement on regional  
6 market operations and developments is crucial to efficient and sustainable markets  
7 that deliver public benefits.”<sup>20</sup> The Oregon-allocated portion of PacifiCorp’s fee is  
8 \$23,463.

9 **Q. What is the WPP WRAP?**

10 A. As I discuss earlier in my testimony, the WPP WRAP is the new regional resource  
11 adequacy initiation that is being implemented by many utilities and power producers  
12 across the west to ensure that the region is better able to plan for our regional resource  
13 adequacy needs.

14 **Q. Please explain the WPP WRAP Fee.**

15 A. There are three main components of the WRAP fee. First is facilitation and  
16 coordination services, including the use of staff resources related to facilitation and  
17 coordination services provided by WPP Corporation in connection with the Phase 3A  
18 Scope of Work. Secondly, WPP will bill to the participants the expenses the WPP  
19 Corporation incurs directly to perform the Phase 3A Scope of Work, including costs  
20 associated with contracting for a Program Operator. Finally, there are binding

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<sup>19</sup> *EIM BOSR Energy Imbalance Market Body of State Regulators*, WESTERN INTERSTATE ENERGY BOARD ofpc2022), <https://www.westernenergyboard.org/energy-imbalance-market-body-of-state-regulators/>.

<sup>20</sup> *2022 Business Plan and Budget*, WESTERN ENERGY IMBALANCE MARKET BODY OF STATE REGULATORS (Oct. 15, 2021) available at <https://www.westernenergyboard.org/wp-content/uploads/EIM-BOSR-2022-Business-Plan-and-Budget-15-Oct-2022.pdf>.

1 program preparation costs including preparation for Federal Energy Regulatory  
2 Commission filings, setting up an independent board and preparing the WPP  
3 Corporation to undertake the obligations required to house the program as a public  
4 utility under the Federal Power Act. The Oregon-allocated cost of this fee is  
5 \$260,703.

## 6 VIII. CONCLUSION

7 **Q. Please summarize your recommendation to the Commission.**

8 A. The Commission should adopt PacifiCorp's proposal to allow for a Rate-Year Update  
9 and incorporate more accurate hydrologic data in the TAM. Additionally, the balance  
10 of risk around NPC has shifted substantially since the PCAM was originally adopted,  
11 and as a result, PacifiCorp has proposed modest changes to the PCAM mechanism.  
12 PacifiCorp recommends that these changes be adopted. Finally, I recommend that the  
13 Commission authorize certain new fees around participation in important regional  
14 organizations be included in base rates.

15 **Q. Does this conclude your direct testimony?**

16 A. Yes.



Docket No. UE 399  
Exhibit PAC/401  
Witness: Michael G. Wilding

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Michael G. Wilding  
Proposed Transition Adjustment Mechanism Guidelines**

**March 2022**

**PACIFICORP**  
**OREGON TRANSITION ADJUSTMENT MECHANISM (TAM)**  
**General Guidelines**

PacifiCorp’s (PacifiCorp or the Company) Transition Adjustment Mechanism (TAM) is an annual filing with the objective to update the forecast net power costs (NPC) to account for changes in market conditions, with the final forecast update close to the direct access window to capture costs associated with direct access, and to correctly identify the proper amount for the transition adjustment.

When filed on a stand-alone basis, the TAM is intended to be narrower and more streamlined than when the TAM is filed in or processed concurrently with a general rate case. In any case, parties to the TAM proceeding should have a full opportunity to review, challenge and litigate issues raised in the case. Parties may address the issue of whether a particular TAM proceeding should have three rounds of testimony or five at the prehearing conference.

Issues related to the prudence of contracts, the appropriate modeling of contracts and known and measurable changes to inputs for existing methodologies are within the proper scope of a stand-alone TAM proceeding. Nothing in these guidelines prevents any Party, including the Company, from advocating in a future general rate case or other proceeding other than a stand-alone TAM, that the TAM should be eliminated or revised.

**A. NPC**

**Commented [A1]:** New Section included for clarification.

NPC includes the amounts booked to the following Federal Energy Regulatory Commission (FERC) accounts:

FERC Account	Description
Account 447	Sales for resale, excluding revenues that are not modeled in the NPC forecast
Account 501	Fuel, steam generation; excluding costs that are not modeled in the NPC forecast
Account 503	Steam from other sources
Account 547	Fuel, other generation
Account 555	Purchased power, excluding the Bonneville Power Administration (BPA) residential exchange credit pass-through if applicable
Account 565	Transmission of electricity by others.

## B. Initial Filing – Forecast NPC

Each year, the Company will make an Initial Filing to forecast NPC for the following calendar year, and set direct access transition adjustments for the following calendar year. In any future TAM filings after UE 400, the Initial Filing will be consistent with the following provisions:

1. At least 30 days prior to the Initial Filing, the Company will provide a pre-filing notice of substantial changes to the methodologies used to forecast NPC. The Company will include in its TAM filing a justification for each substantial change in forecast methodology, calculation of cost elements, or other major data input changes. For each change, where practical, the Company will also provide workpapers that contain a side-by-side comparison of NPC forecast model results with and without the proposed change.
2. The Company will include in the NPC forecast the variable costs and dispatch benefits of new resources that are not eligible for inclusion in the Renewable Adjustment Clause in its NPC in stand-alone TAM proceedings, irrespective of whether the fixed capital costs of the new resource are already included in rates, if: (a) the Company acquired the resource prior to April 1st of the year of the stand-alone TAM filing, or (b) the Company built the resource and it was used and useful prior to April 1st of the year of the stand-alone TAM filing.
3. The prudence of the decision to build or acquire the resource may be determined in the stand-alone TAM proceeding prior to including the variable costs and dispatch benefits in rates. The Company will provide notice to the parties if a new resource subject to this section will be included in the TAM filing by March 1st of the year of the stand-alone TAM filing.
4. The Initial Filing will include updates to all of the NPC components identified in Section A. These costs will be based on the Company's most recent official forward price curve, forecast load and allocation factors. In a stand-alone TAM filing, the Company will also update other revenues that are tracked in FERC Account 456 - Other Electric Revenue. When a TAM is filed in or processed concurrently with a general rate case, this element may be included in the TAM or the general rate case. Additionally, the TAM forecast will include production tax credits (PTC).
5. In the Initial Filing the Company will identify and provide adequate support for all known contracts it expects to be updated or added in the Rebuttal and Final Updates. The Company may update or add a contract not identified in the Initial Filing if the Company demonstrates that it has followed the notification procedures in Section A4 of these guidelines and: (1) the new contract or contract update is based upon new information of which the Company reasonably became aware after the NPC study for the Initial Filing was completed; or (2) the omission resulted from a mistake that occurred despite the Company's reasonable diligence in meeting its

Commented [A2]: Order No. 09-432

Commented [A3]: Order No. 09-432

obligations under this Section. The Company will also identify any contracts modeled in the test period under which the Company has made a liquidated damages claim.

6. In any TAM proceeding, the Company has a continuing obligation to provide notice of any correction or omission promptly after the discovery of the error or new information. In addition, the Company will file a summary of all identified corrections or omissions to the components included in the Initial Filing 15 business days before Staff and Intervenor Direct Testimony is due.
7. The Company will provide access to the NPC model to Parties when it makes its Initial Filing, provided that the Party has entered into a confidentiality agreement with the Company or is subject to a protective order applicable to the relevant TAM or general rate proceeding. The Company agrees to provide an Aurora license to Commission Staff and intervenors for the TAM. PacifiCorp will provide all inputs, data, model settings, additional constraints, and any other modeling changes that are identical to those included in the Aurora model runs used for the Company's TAM application. The Parties preserve their right to challenge the confidential designation of any documents or data.
8. The Company agrees to conduct one Aurora model run per intervenor, so long as the request is reasonable and the Company has reasonable time to complete the request during future NPC forecast mechanism proceedings.
9. The Company will provide workpapers and other supporting documents as specified in Attachment A.
10. The Parties agree to ask the Commission to make the protective order for the next TAM an ongoing protective order which will continue to be effective in future TAM proceedings.
11. The Company agrees to provide testimony in the initial TAM or other NPC forecast filing regarding the prudence of any Coal Supply Agreements (CSA) that were entered into after its reply testimony of the previous year's NPC forecast proceeding. PacifiCorp will notify Parties in the event of the execution of a CSA following the Company's initial testimony but prior to conclusion of the NPC forecast filing and work with Parties to identify the appropriate review timeline, regulatory process and rate implementation.
12. The Company will provide workpapers in the filing to support the depreciable lives of Bridger Coal Company assets.
13. In future power cost forecast proceedings, the Company agrees to provide the Commission for the most recent past actual calendar year: for each hour of the sales period: the \$/megawatt-hour (MWh) of bilateral trades total wholesale sales revenue(\$); total energy delivered (MWh) through wholesales sales; hourly generation logs for

Commented [A4]: Order No. 20-392

Commented [A5]: Order No. 20-392

Commented [A6]: Order No. 20-392

PacifiCorp owned generation; and monthly generation unit production costs (\$/MWh). If the Company joins expanded markets in the future such as the proposed California Independent System Operator Extended Day-Ahead Market, the Company agrees to work with intervenors to identify additional wholesale sales data to be provided in future forecast NPC filings.

Commented [A7]: Order No. 20-392

14. The Company will show the output (MWh) and PTC benefits (\$) for its wind fleet. The Company will explain its grossed-up PTC value used for the PTC benefits explain and quantify the other NPC benefits from the wind projects, whether the wind output displaces the Company's higher cost generation, or excess wind output is forecast to be sold to the market with revenues that benefit customers.

15. Within 30 days of the Initial Filing, PacifiCorp will deliver to the Parties a sample calculation of Schedule 296 as applicable to customers currently served under rate schedules 30 and 48 (Primary).

Commented [A8]: Order No. 20-392

16. These Guidelines do not limit the ability of other Parties to propose updates consistent with these Guidelines after the Company's Initial Filing.

### C. Rebuttal Update Filing – Forecast NPC

At the time the Company makes its Rebuttal Update Filing, it will include an update to forecast NPC consistent with the following provisions:

1. The Company will update the following NPC components, subject to the Guidelines:
  - a. Most recent official forward price curve.
  - b. New power, fuel and transportation/transmission contracts, both physical and financial, and updates to existing contracts. These contracts include:
    - i. wholesale electric sales and purchase contracts that are for long term firm sales and purchases, short term firm sales and purchases, or exchanges and storage with and without energy or capacity prices;
    - ii. coal and natural gas sales, purchases and transportation contracts;
    - iii. wheeling contracts; and
    - iv. coal contracts for mines directly or indirectly owned by the Company.
    - v. The latest hydrology condition forecast available from the National Oceanic and Atmospheric Administration's (NOAA) Northwest River Forecast Center (NWRFC);

Commented [A9]: New Section – See Testimony

These transactions may have fixed prices or prices linked to market indexes. They may require physical deliveries or be settled financially (*e.g.*, swaps). Contracts must be independent and verifiable.

2. In its Rebuttal Update Filing, the Company may make corrections to or address omissions in the components included in the Initial Filing. The Company may make corrections or address omissions in the components included in the Rebuttal Update Filing within five business days of the date of filing of the Rebuttal Update. The Company agrees to provide notice of any impending correction promptly after the discovery of the error and agrees to correct all errors and omissions within five business days of the initial Rebuttal Update Filing.
3. Parties reserve all of their procedural rights, including the right to submit data requests and seek postponement of the hearing, related to the correction of the Rebuttal Update Filing.
4. The Company will provide workpapers and the other supporting documents as specified in Attachment A.

**D. Final Updates – Forecast NPC**

The Company will file Final Updates to forecast NPC and calculate transition adjustments as follows, subject to the Guidelines:

1. At least five business days prior to the direct access window, the Company will:
  - a. File an update to forecast NPC, incorporating the following:
    - i. Commission-ordered adjustments;
    - ii. Forward Price Curve from within nine days of the filing date;
    - iii. New contracts, or updates to existing contracts. These contracts include: (a) wholesale electric sales and purchase contracts that are for long term firm sales and purchases, short term firm sales and purchases, or exchanges and storage with and without energy or capacity prices; and (b) natural gas sales and purchase contracts. These transactions may have fixed prices or prices linked to market indexes. They may require physical deliveries or be settled financially (*e.g.*, swaps);
    - iv. The latest hydrology condition forecast available from the NOAA NWRFC;
  - b. Post indicative transition adjustments for Schedules 294 and 295;

Commented [A10]: New Section – See Testimony

- c. Provide indicative supply service NPC rates (to be Schedule 201); and
  - d. Provide an attestation that will confirm that all contracts executed prior to the contract lockdown date have been included in the Indicative Filing and will identify any exceptions and the reason why such contracts were excluded. The attestation will also include a statement confirming that, for the executed power purchase agreements with new qualifying facilities (QFs) included in the TAM, PacifiCorp has a commercially reasonable good faith belief that these QFs will reach commercial operation during the rate effective period based on the information known to the Company as of the contract lockdown date. This attestation does not require the Company to opine on the commercial viability of any QF.
2. On November 15, in accordance with OAR 860-038-0275(1), the Company will:
  - a. File an update to NPC incorporating the forward price curve from within seven days of the filing date.
  - b. Post final transition adjustments for Schedules 294 and 295.
    - i. Transition Adjustments in Schedules 294 and 295 will be calculated based on the Final Update and consistent with the modification to the calculation described in Section 15 of the Stipulation adopted by the Commission in Order 08-543 in Docket UE-199 and modified so that any remaining monthly thermal generation that is backed down for assumed direct access load will be priced at the simple monthly average of the California-Oregon Border (COB) price, the Mid-Columbia price, and the avoided cost of thermal generation as determined by Aurora. The monthly COB and Mid-Columbia prices will be applied to the heavy load hours or light load hours separately. The existing balancing account mechanisms will remain in effect.
  - c. Provide supply service NPC rates (to be Schedule 201)
3. The Company will provide workpapers and other supporting documents for both the Indicative and Final Update filings as specified in Attachment A.
4. Challenges to Final Updates. Without waiving any procedural rights, the Parties agree to make a good faith effort to follow the following procedures for challenges to the Final Updates and compliance filing. Staff and Intervenors retain their procedural rights to raise any issue regarding the Company's Final Updates to the Commission prior to and during the Commission public meeting, including filing for a deferral of costs related to the final TAM updates or requesting that a portion of the TAM be allowed subject to refund.

Commented [A11]: Order No. 10-363 and Order No. 14-331

- a. PacifiCorp agrees to make a good faith effort to respond to all discovery requests after the Indicative Filing in five business days.
- b. At least 10 business days before the Commission public meeting scheduled immediately prior to the effective date of the compliance filing, a Party will make a good faith effort to provide notice to the Parties of any potential concerns with the Company's Final Updates. The notice will identify the specific elements of the Updates that are relevant to the potential challenge and provide an explanation of the Party's concern.
- c. No more than five business days after receiving the Party's notice, the Company will provide an initial response to the Parties regarding the concerns raised in the notice and the Parties will work to reach resolution of the issue.
- d. If the matter is not resolved by the Parties prior the Commission public meeting, the Parties may make recommendations to the Commission at the public meeting to set a process to resolve the matter, if additional process is required. The recommendations may include that a specific amount of the tariff change will be subject to deferral until the Commission resolves the matter through additional process.
- e. The Company will not oppose the filing of a deferral of any limited and specific cost which is identified by the Parties at least 10 business days before the Commission public meeting. Specifically, the Company will not challenge the deferral on the basis that it fails to meet the Commission's standards for deferred accounting as initially set forth in Order No. 05-1070 (docket UM 1147), including issues related to the materiality of the filing and a showing of substantial harm. The Company otherwise retains the right to object to subject to refund or deferral treatment.
- f. The Parties agree to request a schedule that will result in a Commission decision within 90 days of the effective date for new rates for any additional process after the Commission public meeting.
- g. If the final Commission decision on any challenges to the Final Updates results in changes to the transition adjustments approved in Schedules 294 and 295, the Company may reflect in the direct access balancing account any difference between the approved transition adjustments and the transition adjustments that would have been in effect consistent with the Commission's decision on the challenged items.

Commented [A12]: Order No. 10-363 and 13-474

**E. Rate Year TAM Update**

Commented [A13]: New Section – See Testimony

1. On March 1 of the rate year (after the Final Update), the Company will file the Rate Year Update filing to update Schedule 201 rates to account for the following updates:
  - a. The latest forward price curve available to the Company;



- b. New contracts, or updates to existing contracts. These contracts include: (a) wholesale electric sales and purchase contracts that are for long term firm sales and purchases, short term firm sales and purchases, or exchanges and storage with and without energy or capacity prices; and (b) natural gas sales and purchase contracts. These transactions may have fixed prices or prices linked to market indexes. They may require physical deliveries or be settled financially (e.g., swaps);
  - c. The latest hydrology condition forecast available from the NOAA NWRFC;
2. These rates will take effect April 1, and any challenges will follow the process laid out in the preceding section D. 4.

#### **F. Rate Design**

1. In the Company's current general rate case, proposed NPC are unbundled from other generation costs. All NPC will be collected through a new Schedule 201, Annual Power Cost Adjustment, which will be applied as a rider to Schedule 200. Schedule 200 will continue to collect other generation costs.
2. In any future TAM filed in or processed concurrently with a general rate case, the TAM rate design test year will be the general rate case rate design test year. In a stand-alone TAM, the TAM rate design test year will be the forecast test year during which the Schedule 201 rates will be effective.
3. In any future TAM filed in or processed concurrently with a general rate case, proposed Schedule 201 revenues by rate schedule will be determined by spreading the total forecast NPC for the test year to the rate schedules in the same manner as the revenues for Schedule 200 are spread to the rate schedules: based on the functionalized revenue requirement as determined by the Commission based upon a Cost of Service study, or by the method proscribed by the Commission in the most recent general rate case or Commission proceeding regarding rate spread and rate design.
4. In any future stand-alone TAM, Proposed Schedule 201 revenues by rate schedule will be determined by spreading the total forecast NPC for the test year to the rate schedules based upon each schedule's proportion of "Present Schedule 201 revenues." "Present Schedule 201 revenues" for the test year shall reflect the projected test year sales forecasts. Proposed Schedule 201 rate design shall reflect the method prescribed by the Commission in the most recent general rate case or other Commission proceeding regarding rate spread and rate design.

#### **G. TAM Filings Made in or Processed Concurrently with a General Rate Case**

1. If the Company files a general rate case prior to April 1 in a given year, then the Company may file the TAM before April 1. If the Company chooses not to file a TAM prior to April 1, then it must file on April 1. If the TAM is filed on a stand-alone basis,

it will be filed no later than April 1. In order to accommodate the direct access window that begins November 15, the TAM may be bifurcated from the full general rate case in order to allow for a Commission decision by November 1. Bifurcation of the TAM does not alter any provision below.

2. When a TAM is filed in or processed concurrently with a general rate case, the Company or any Party may propose changes to how the Company's Rate Mitigation Adjustment or other rate spread tools should operate in a stand-alone TAM filing made before the TAM is again filed in or processed concurrently with a general rate case.
3. When a TAM is filed in or processed concurrently with a general rate case, the TAM will be subject to the Update Filings identified above and the agreements on workpapers and other supporting documents specific in Attachment A.

#### **H. Other Provisions**

1. These guidelines do not limit the ability of the Company or other Parties to propose changes to these guidelines, including changes to the cost elements that will comprise NPC in stand-alone TAM proceedings or in future general rate cases.

**REDACTED**  
Docket No. UE 399  
Exhibit PAC/500  
Witness: Timothy J. Hemstreet

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**REDACTED**  
**Direct Testimony of Timothy J. Hemstreet**

**March 2022**

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1                                   **I. INTRODUCTION AND QUALIFICATIONS**

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

4   A. My name is Timothy J. Hemstreet. My business address is 825 NE Multnomah  
5   Street, Suite 1800, Portland, Oregon 97232. My title is Managing Director of  
6   Renewable Energy Development for PacifiCorp.

7   **Q. Please describe your education and professional experience.**

8   A. I hold a Bachelor of Science degree in Civil Engineering from the University of  
9   Notre Dame in Indiana and a Master of Science degree in Civil Engineering from  
10   the University of Texas at Austin. I am also a Registered Professional Engineer  
11   in the state of Oregon. Before joining PacifiCorp in 2004, I held positions in  
12   engineering consulting at CH2M HILL (now Jacobs Engineering, Inc.) and  
13   environmental compliance at RR Donnelley Norwest, Inc. Since joining  
14   PacifiCorp, I have held positions in environmental policy and compliance,  
15   engineering, project management, and hydroelectric project licensing and  
16   program management. In 2016, I assumed a role in renewable energy  
17   development, focusing on PacifiCorp's wind repowering effort, and assumed my  
18   current role in June 2019, in which I oversee the development of renewable  
19   energy resources that enhance and complement PacifiCorp's existing renewable  
20   energy resource portfolio.

21   **Q. Have you testified in previous regulatory proceedings?**

22   A. Yes. I have previously sponsored testimony in California, Idaho, Oregon, Utah,  
23   Washington, and Wyoming.

1 **II. PURPOSE OF TESTIMONY**

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

3 A. The purpose of my testimony is to provide an overview of the TB Flats Wind  
4 Project and provide an update on the status of the project.

5 **Q. Did the Company include the TB Flats Wind Project in its recent general  
6 rate case in docket UE 374 (2021 Rate Case)<sup>1</sup>?**

7 A. Yes. The TB Flats Wind Project was included in the Company's revenue  
8 requirement in the 2021 Rate Case, and the Commission found the project prudent  
9 and in the public interest; however, as a result of the construction delays  
10 associated with the coronavirus pandemic, the project could not be completed in  
11 2020 and only costs associated with turbines that achieved commercial operation  
12 by December 20, 2020, were included in rates. When it became apparent that full  
13 completion of the project would not occur by June 30, 2021, the Company met  
14 with parties in the 2021 Rate Case to discuss the best means of reflecting the full  
15 cost of the project in customer rates and as a result of those discussions  
16 determined that it would seek recovery for the remaining project costs in its next  
17 general rate case.

18 **III. TB FLATS WIND PROJECT**

19 **Q. Please provide a brief overview of the TB Flats Wind Project.**

20 A. TB Flats is a 500-megawatt (MW) wind generation facility and associated  
21 infrastructure, located on approximately 41,000 acres of leased private and state  
22 land in Carbon and Albany Counties, Wyoming. The facilities consist of 132

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<sup>1</sup> *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).*

1 wind turbine generators (WTGs), an electrical collector system, collector  
2 substations, access roads, meteorological towers, an operations and management  
3 building, communication equipment, and supervisory control and data acquisition  
4 control equipment.

5 **Q. What are the details of the technologies that are used in this project?**

6 A. The TB Flats Wind Project uses modern WTG equipment supplied by Vestas-  
7 American Wind Technology, Inc. (Vestas), consisting of 28 Vestas model V110-  
8 2.0 WTGs and 104 Vestas model V136-4.3 WTGs. The Vestas WTGs are pitch-  
9 regulated upwind turbines with active yaw, gearboxes and three-bladed rotors.  
10 The V110-2.0 WTG has a 2.0 MW generator capacity, a rotor with a 110-meter  
11 diameter, and a hub height of 80 meters. The V136-4.3 WTG has a 4.3 MW  
12 generator capacity, a rotor with a 136-meter diameter, and a hub height of  
13 82 meters. The WTGs use a microprocessor-controlled pitch control system that  
14 allows the WTGs to operate with a variable rotor speed to help maintain output at  
15 or near their rated power.

16 **Q. Please describe any changes to the Company's existing utility plant/system**  
17 **that were necessary to integrate the TB Flats Wind Project with the**  
18 **Company's system.**

19 A. Integration of the TB Flats Wind Project required the completion of specific  
20 interconnection facilities and network upgrades to allow the project to  
21 interconnect to the Company's electrical transmission system. The  
22 interconnection facilities consisted of circuit breakers and metering at the point of  
23 interconnection and the network upgrades consisted of the installation of new

1 breakers and corresponding bus and relay upgrades at the Shirley Basin  
2 substation, and a new transmission line from the Shirley Basin substation to the  
3 Aeolus substation.

4 **Q. What is the current construction status of the TB Flats Wind Project?**

5 A. All of the 132 WTGs have been erected and commissioned, and the project is  
6 serving customers.

7 **Q. What was the impact of the coronavirus pandemic on construction at the TB  
8 Flats Wind Project?**

9 A. The pandemic caused severe delays in the delivery of wind turbine equipment to  
10 the project. The pandemic first impacted the production of wind turbine  
11 components and electrical parts sourced by the turbine supplier from Asia, where  
12 the impacts of the pandemic were first experienced and factory shutdowns  
13 occurred. These impacts then spread to European manufacturing facilities  
14 producing wind turbine components necessary for the project. Ultimately, the  
15 wave of global manufacturing shutdowns affected domestic WTG manufacturing  
16 and assembly facilities. When production resumed, adherence to worker safety  
17 protocols and reduced workforce slowed productivity. In addition to the  
18 shutdown of manufacturing facilities, impacts to logistics were experienced that  
19 delayed the movement of manufactured components to final WTG manufacturing  
20 and assembly facilities located in Colorado, and from those facilities to the project  
21 site. When equipment was received, it often was not able to be delivered to the  
22 site in an efficient manner to support the construction sequence for the project  
23 given the logistics constraints that were being experienced. Due to the turbine



1 equipment delivery delays, 28 WTGs were unable to be delivered to the site  
2 during the 2020 construction season in time to allow for their erection in 2020  
3 prior to the onset of winter weather conditions and high wind speeds that preclude  
4 efficient delivery, construction, commissioning, and maintenance activities.

5 In addition to the delays associated with receiving wind turbine  
6 components to the project site, construction productivity was also affected.  
7 Worker safety protocols implemented in conformance with public health  
8 guidelines reduced productivity, slowing construction efforts. Labor resources  
9 were also limited by adherence to crew quarantine protocols following  
10 documented coronavirus exposures, as well as reduced staffing levels as a result  
11 of fewer workers being able or willing to work under the health and safety  
12 protocols required. At times, experienced work crews needed to be quarantined  
13 and less experienced crews that required additional training were needed. The net  
14 result of these impacts was that the project could not be completed in 2020 as  
15 planned and construction efforts were delayed into the fall and winter period.  
16 This resulted in work being conducted when there were increased wind speeds  
17 and less favorable weather conditions, which limited the periods when workers  
18 were able to access the wind turbines to complete construction and  
19 commissioning activities. Winter conditions, including ice and snow, also slowed  
20 construction progress and turbine erection activities were halted during the winter  
21 period when high wind speeds and site access limitations due to snow and ice did  
22 not allow work to proceed.

1 **Q. What steps did the Company take to mitigate the impact of the pandemic on**  
2 **the project and address the construction delays?**

3 A. First and foremost, the Company worked with its contractors to implement  
4 recommended worker safety and public health protocols as that guidance became  
5 available to keep work crews healthy and limit transmission of the virus among  
6 and between work crews. New work methods were established to enable work to  
7 proceed while limiting the number of workers that needed to be physically  
8 proximate and to reduce mixing among the work crews. The Company also  
9 worked closely with the turbine supplier to track changing WTG production and  
10 shipping schedules so that adjustments could be made to match available labor  
11 and equipment on the project with available equipment deliveries. The  
12 construction sequencing was also changed to keep available work crews busy  
13 even though all of the equipment necessary to complete a WTG may not have  
14 been available at a particular turbine location. The Company also worked to  
15 increase construction efficiencies by using available equipment across the three  
16 wind projects in Wyoming (TB Flats, Ekola Flats, and Foote Creek I) that were  
17 using similar Vestas V136 WTG equipment in 2020 so that construction was not  
18 halted due to a lack of parts that were available at another project. The Company  
19 also worked with Vestas to evaluate changes to shipping and logistics plans to  
20 determine the most efficient means to advance the project.

21 **Q. When was construction at the TB Flats Wind Project completed?**

22 A. Turbine commissioning activities proceeded throughout the winter of 2020-2021  
23 when weather conditions allowed, and significant construction progress resumed

1 in the spring of 2021. Delivery of the final 28 WTGs to the project site was  
2 completed in May 2021 and turbine erection activities were able to continue as  
3 wind speeds dropped. Turbine erection and commissioning proceeded into the  
4 summer and the final WTGs at the project were placed into commercial operation  
5 on July 26, 2021.

6 **Q. What are the final project costs associated with the TB Flats Wind Project?**

7 A. The final project costs reflected in this filing are approximately \$ [REDACTED] million.  
8 This is slightly higher than the projected cost of \$ [REDACTED] million that was reflected  
9 and approved by the Commission in the 2021 Rate Case. The increase in  
10 forecasted costs is due to construction delays attributed to disruption in the  
11 worldwide supply chain caused by the coronavirus pandemic. This resulted in  
12 delay of project completion into 2021 and resulting project costs associated with  
13 that delay. These costs included higher costs associated with turbine supply,  
14 balance of plant construction, internal project management and construction  
15 oversight, capitalized property taxes, and higher Allowance for Funds Used  
16 During Construction costs, which were partially offset by savings on budgeted  
17 items. Ms. Sherona L. Cheung explains the revenue requirement treatment in the  
18 2021 Rate Case and the Company's request in this application.

19 **Q. Does this conclude your direct testimony?**

20 A. Yes.

Docket No. UE 399  
Exhibit PAC/600  
Witness: Richard A. Vail

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Direct Testimony of Richard A. Vail**

**March 2022**

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**ATTACHED EXHIBITS**

Exhibit PAC/601—Goshen to Sugarmill to Rigby 161 kV Transmission Line Project

Exhibit PAC/602—Jordanelle to Midway 138 kV Transmission Line Project

1                                   **I.    INTRODUCTION AND QUALIFICATIONS**

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

4   A.    My name is Richard A. Vail. My business address is 825 NE Multnomah Street, Suite  
5       1600, Portland, Oregon 97232. My present position is Vice President of  
6       Transmission. I am responsible for transmission system planning, customer generator  
7       interconnection requests and transmission service requests, regional transmission  
8       initiatives, capital budgeting for transmission, transmission and distribution project  
9       delivery, and administration of the Open Access Transmission Tariff (OATT).

10 **Q.    Please describe your education and professional experience.**

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

18                                   **II.    PURPOSE OF TESTIMONY**

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

20 A.    The purpose of my testimony is to describe PacifiCorp's transmission system and the  
21       benefits it provides to Oregon customers. PacifiCorp's transmission system is  
22       designed to reliably transfer electric energy from a broad array of generation  
23       resources to load. PacifiCorp's interconnection to other balancing authority areas

1 (BAAs) and participation in the Energy Imbalance Market (EIM) provide access to  
2 markets and promote affordable and reliable service to PacifiCorp's customers.  
3 Further, all transmission system capacity increases provide benefits to customers by  
4 increasing reliability and allowing more generation to interconnect to serve customer  
5 load, as well as allowing PacifiCorp flexibility in designating generation resources for  
6 reserve capacity to comply with mandatory reliability standards.

7 I also specifically describe PacifiCorp's major capital investment projects for  
8 new transmission systems included in this rate case. My testimony demonstrates that  
9 the Company has made prudent decisions related to these projects and that these  
10 investments result in an immediate benefit to PacifiCorp's customers in Oregon.

11 I recommend that the Public Utility Commission of Oregon (Commission) find these  
12 investments prudent and in the public interest.

13 **III. OVERVIEW OF PACIFICORP'S TRANSMISSION SYSTEM AND**  
14 **INVESTMENT DRIVERS**

15 **Q. Please briefly describe PacifiCorp's transmission system.**

16 A. PacifiCorp owns and operates approximately 17,700 miles of transmission lines  
17 ranging from 46 kilovolts (kV) to 500 kV across multiple western states. PacifiCorp  
18 has nearly two million customers with approximately 631,000 customers located in  
19 Oregon.

20 For convenience in load and resource planning, PacifiCorp groups its local  
21 area transmission and distribution system into load areas. These load areas are  
22 regions in which the PacifiCorp system is generally contiguous within the load area,  
23 while a set of transmission constraints and boundaries separate the load area from

1 other portions of the PacifiCorp system. In Oregon, PacifiCorp generally has three  
2 primary load areas: Southern Oregon, Central Oregon, and the Willamette Valley.  
3 These primary load areas are further divided into 23 sub-areas within Oregon for  
4 planning purposes when evaluating the capability of the PacifiCorp system to meet  
5 the load and resource requirements of its customers.

6 **Q. Please describe PacifiCorp's responsibility for maintaining reliability on its**  
7 **transmission system.**

8 A. In 1996, the Federal Energy Regulatory Commission (FERC) issued Order No. 888,<sup>1</sup>  
9 which required that transmission system owners provide non-discriminatory access to  
10 their transmission systems. PacifiCorp is obligated under its OATT to plan its  
11 transmission system for the open access of all transmission customers. Through the  
12 OATT Attachment K local planning process and the FERC Order 1000 regional and  
13 inter-regional planning processes, PacifiCorp participates in open stakeholder  
14 planning processes covering its entire transmission footprint. These planning  
15 processes result in system plans that incorporate economics, reliability, and public  
16 policy inputs and requirements. PacifiCorp must also coordinate with other entities in  
17 the region for transmission planning purposes as required under FERC Order 1000.<sup>2</sup>  
18 In addition to these more general requirements, PacifiCorp also must comply with the  
19 specific requirements of the mandatory reliability standards approved by FERC.

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<sup>1</sup> *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Pub. Util.; Recovery of Stranded Costs by Pub. Util. and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

<sup>2</sup> *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Util.*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011), order on reh'g, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), order on reh'g, Order No. 1000-B 141 FERC ¶ 61,044 (2012).



1 **Q. Who establishes transmission reliability standards?**

2 A. FERC directs the North American Electric Reliability Corporation (NERC) to  
3 develop reliability standards to ensure the safe and reliable operation of the Bulk  
4 Electric System (BES) in the United States in a variety of operating conditions. On  
5 April 1, 2005, NERC established a set of transmission operations reliability standards.  
6 A subset of the transmission reliability standards are the transmission planning  
7 standards (TPL Standards). The purpose of the TPL Standards is to “establish  
8 Transmission system planning performance requirements within the planning horizon  
9 to develop a BES that will operate reliably over a broad spectrum of System  
10 conditions and following a wide range of probable Contingencies.”<sup>3</sup> The TPL  
11 Standards, along with regional planning criteria (*i.e.*, regional planning criteria  
12 established by the Western Electricity Coordinating Council (WECC)) and utility-  
13 specific planning criteria, define the minimum transmission system requirements to  
14 safely and reliably serve customers.

15 **Q. How does PacifiCorp ensure compliance with the TPL Standards?**

16 A. The Company plans, designs, and operates its transmission system to meet or exceed  
17 NERC Standards for BES and WECC regional standards and criteria. To ensure  
18 compliance with applicable TPL Standards, PacifiCorp conducts an annual system  
19 assessment to evaluate the performance of the Company’s transmission system and to  
20 identify system deficiencies. The annual system assessment is comprised of steady-

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<sup>3</sup> See <http://www.nerc.com/files/tpl-001-4.pdf>.

1 state, stability, and short circuit analyses<sup>4</sup> to evaluate peak and off-peak load seasons  
2 in the near-term (one-, two-, and five-year) and long-term (10-year) planning  
3 horizons. The assessment is performed using power flow base cases maintained by  
4 WECC and developed in coordination among all transmission planning entities in the  
5 Western Interconnection. These base cases include load and resource forecasts along  
6 with planned transmission system changes for each of the future year cases and are  
7 intended to identify future system deficiencies to be mitigated.

8 As part of the annual system assessment, corrective action plans are developed  
9 to mitigate identified deficiencies, and may prescribe construction of transmission  
10 system reinforcement projects or, as applicable, adoption of new operating  
11 procedures. In certain instances, operating procedures prescribing action to change  
12 the configuration of the transmission system can prevent deficiencies from occurring  
13 when there are two back-to-back (N-1-1) (or concurrent) transmission system events.  
14 However, the use of operating procedure actions has limitations. In particular, actions  
15 taken in connection with operating procedures that are designed to protect the  
16 integrity of the larger integrated transmission system in the Western Interconnection  
17 of the United States can lead to large numbers of customers being at risk of an outage  
18 upon the occurrence of the second of two back-to-back (N-1-1) events. An effective  
19 corrective action plan is critical to ensuring system reliability so that large numbers of  
20 customers are not subjected to avoidable outage risk.

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<sup>4</sup> Analyses consist of taking a normal system (N-0) and applying events (N-1, N-1-1, N-2, etc.) within each category (P0, P1, P2, P3, etc.) listed within the TPL Standards in order to identify system deficiencies. Example: An N-1-1 event describes two transmission system elements being out of service at the same time, but due to independent causes. An example of an N-1-1 event would be a planned outage of one 230 kV transmission line followed by an unplanned outage of any element in the system being used to continue service with the initial element out.

1 **Q. Is compliance with the reliability standards optional?**

2 A. No. The reliability standards are a federal requirement, subject to oversight and  
3 enforcement by WECC, NERC, and FERC. PacifiCorp is subject to compliance  
4 audits every three years and may be required to prove compliance during other NERC  
5 or WECC reliability initiatives or investigations. Failure to comply with the  
6 reliability standards could expose the Company to penalties of up to \$1 million per  
7 day, per violation. Accordingly, and as described more fully later in my testimony,  
8 compliance with reliability standards is a major driver for the new capital investments  
9 in PacifiCorp's system transmission assets identified in and supported by my  
10 testimony.

11 **Q. Please identify other drivers that are relevant to the capital investments in  
12 PacifiCorp's transmission system described in your testimony.**

13 A. There are several other drivers that inform whether PacifiCorp will build new  
14 transmission facilities, including increased demand for transmission capacity, requests  
15 for transmission service, and the age and condition of existing transmission facilities.  
16 The specific drivers for the projects addressed in my testimony are described in more  
17 detail later in my testimony.

18 **IV. OVERVIEW OF INVESTMENTS DESCRIBED IN TESTIMONY**

19 **Q. What specific transmission system investments are you addressing in your  
20 testimony?**

21 A. My testimony addresses PacifiCorp's major new transmission system projects  
22 included in this general rate case filing. Specifically, my testimony addresses the  
23 following projects:

1           **1. Goshen to Sugarmill to Rigby 161 kV Transmission Line Project**

2           The Goshen to Sugarmill to Rigby 161 kV transmission line rebuild of an  
3           existing 69 kV line from Goshen substation to Sugarmill substation and then  
4           construction of a new 161 kV line from Sugarmill substation to Rigby substation  
5           located in the southeast Idaho area, as shown in the map attached in Exhibit PAC/601;  
6           and

7           **2. Jordanelle to Midway 138 kV Transmission Line Project**

8           The Jordanelle to Midway 138 kV transmission line project constructed nine  
9           miles of 138 kV transmission line between Midway and Jordanelle substations in  
10          Utah, as shown in the map attached in Exhibit PAC/602.

11       **Q.    What are the projected costs associated with these transmission investments and**  
12       **their associated in-service dates?**

13       A.    Table 1 identifies the specific projects and associated costs and in-service dates.

<b>TABLE 1</b>		
<b>Project</b>	<b>Total Company Cost (\$m)</b>	<b>In-Service Date</b>
Goshen-Sugarmill-Rigby 161kV Transmission Line Project	\$23.2m	July 2022
Jordanelle-Midway 138kV Transmission Line Project	\$21.9m	December 2021

14          These amounts include costs associated with engineering, project  
15          management, materials and equipment, construction, right-of-way (including rights  
16          acquired by condemnation), and an allowance for funds used during construction.  
17          These costs are also shown in the testimony and exhibits of Ms. Sherona L. Cheung.  
18          The in-service dates are based on the best available information at the time of  
19          preparing this case.

1 **Q. Please briefly describe the benefits associated with these investments.**

2 A. The benefits associated with these investments include increased load serving  
3 capability, enhanced reliability, conformance with NERC Reliability Standards,  
4 improved transfer capability within the existing system, relief of existing congestion,  
5 and interconnection and integration of new wind resources into PacifiCorp's  
6 transmission system. These benefits will be described more fully below.

7 **Q. Will PacifiCorp's OATT transmission customers pay for some of these assets?**

8 A. Yes, through OATT transmission charges. The Company's current transmission  
9 formula rate (included in PacifiCorp's OATT) was approved by FERC in Docket No.  
10 ER11-3643.<sup>5</sup> The Company's transmission formula rate is updated annually with the  
11 annual transmission revenue requirement (ATRR) that represents the annual total cost  
12 of providing firm transmission service over the test year. The ATRR calculation  
13 incorporates all transmission system investments by the Company, a return on rate  
14 base, income taxes, expenses, and certain revenue credits, among other specific  
15 elements and adjustments. Transmission assets, including new transmission capital,  
16 are included in the ATRR, weighted by months in service. The ATRR is converted  
17 into a rate by dividing the ATRR by firm transmission demand. All third-party  
18 revenues for transmission service (along with third-party revenues for ancillary  
19 services) are included as revenue credits in the calculation of rates in each of the  
20 Company's state retail jurisdictions.

---

<sup>5</sup> *In re PacifiCorp*, 143 FERC ¶ 61,162 (May 23, 2013) (letter order approving settlement agreement establishing formula rate).

1 **Q. Please explain how network upgrade cost allocation works under the OATT.**

2 A. In accordance with its OATT, when PacifiCorp receives a request for generation  
3 interconnection or transmission service, the Company completes studies to determine  
4 what new facilities or upgrades to existing facilities are required to accommodate the  
5 request. The studies identify the facilities and upgrades required and classify the  
6 asset additions required to support the service into two categories: direct assigned or  
7 network upgrade. Direct assigned assets are those assets that only benefit or are used  
8 solely by the customer requesting generator interconnection or transmission service.  
9 Those costs are directly assigned and paid for by that customer and will not be  
10 included in either the Company's ATRR or retail rate base. Network upgrades, on the  
11 other hand, are those assets that benefit all customers using the transmission system.  
12 Costs associated with network upgrades are investments by the transmission provider  
13 and are included in PacifiCorp's ATRR<sup>6</sup> and retail rate base.

14 **V. GOSHEN TO SUGARMILL TO RIGBY 161 KV TRANSMISSION LINE**  
15 **PROJECT**

16 **Q. Please describe the investment for the Goshen to Sugarmill to Rigby 161 kV**  
17 **Transmission Line Project.**

18 A. The Goshen to Sugarmill to Rigby 161 kV Transmission Line Project constructs  
19 approximately 44 miles of new transmission lines from the Goshen to Sugarmill and  
20 Sugarmill to Rigby substations located in the southeast Idaho area. Substation

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<sup>8</sup> For generation interconnection customers, those customers may be required to pay the initial cost of network upgrades, subject to refund through credits to invoiced charges for transmission service and full refund of any remaining amounts after 20 years. See Section 11.4 of PacifiCorp's Standard Large Generator Interconnection Agreement (OATT Attachment N, Appendix 6 and available at [http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20190601\\_OATTMASTER.pdf](http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20190601_OATTMASTER.pdf)); see also Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003-B, 109 FERC ¶ 61,287 (Dec. 20, 2004).

1 expansion will be required at Goshen, Sugarmill, and Rigby substations to  
2 accommodate the new 161 kV positions and associated structures and equipment, as  
3 shown on the map attached in Exhibit PAC/601. The project consists of two  
4 sequences of work. The first work sequence, completed in 2020, was to construct  
5 approximately 24 miles of the new Goshen to Sugarmill #2 161 kV transmission line  
6 and perform the required substation construction at Goshen and Sugarmill substations  
7 to terminate the new transmission line at both ends. This first work sequence was  
8 included and approved for recovery in the Company's last rate case proceeding,  
9 docket UE 374.<sup>7</sup>

10 The second work sequence consists of constructing approximately 20 miles of  
11 the new Sugarmill to Rigby #2 161 kV line and performing the required substation  
12 construction at Goshen and Sugarmill substations to terminate the new transmission  
13 line at both ends of the line.

14 As part of this project, PacifiCorp entered into a joint ownership agreement  
15 with Idaho Falls Power to construct 12 miles of new 161 kV shared transmission line  
16 from the corner of Lincoln Road and Hitt Road to Idaho Falls Power's future Paine  
17 Substation. Idaho Falls Power had much of this line already permitted and was able  
18 to secure final permits with the assistance of PacifiCorp while reducing time and  
19 costs required for PacifiCorp to secure permitting for a separate line. PacifiCorp will  
20 own and pay 51 percent of this line segment. Idaho Falls Power completed this  
21 portion of the line in December 2021. PacifiCorp expects to complete the line to  
22 Rigby substation by July 2022.

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<sup>7</sup> *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).*

1 **Q. Please explain why this investment in the Goshen to Sugarmill to Rigby 161 kV**  
2 **Transmission Line Project is needed and beneficial.**

3 A. The need for the Goshen to Sugarmill to Rigby 161 kV line was identified in the 2016  
4 Goshen Area Planning Study to address projected overloads on the Goshen to  
5 Sugarmill 161 kV line and Goshen to Rigby 161 kV line, in addition to low voltage at  
6 Rigby and Sugarmill substations that manifest under heavy loading conditions.  
7 Projected peak summer load conditions in 2021 in the Rigby-Sugarmill area indicate  
8 that under normal operating conditions (N-0) the Goshen to Sugarmill 161 kV line  
9 was expected to load to 100 percent of its continuous rating of 201 megavolt amperes  
10 (MVA) and the Rigby and Sugarmill substations 161 kV bus voltage is expected to  
11 reach its minimum limit of 0.95 per unit. Additionally, the projected load growth  
12 exacerbates several existing N-1 conditions in the area. Based on 2021 load, loss of  
13 the Goshen to Sugarmill 161 kV line causes the Goshen to Rigby 161 kV line to  
14 overload to 179 percent of its four-hour emergency rating and can result in  
15 excessively low voltage down to 0.68 per unit in the Rigby-Sugarmill area. The loss  
16 of the Goshen to Rigby 161 kV line can cause the Goshen to Sugarmill 161 kV line to  
17 overload to 111 percent of its four-hour emergency rating of 255 MVA, overload to  
18 102 percent of its 30-minute emergency rating of 279 MVA and can cause low  
19 voltage down to 0.88 per unit at Rigby substation. The Goshen to Sugarmill 161 kV  
20 line and Goshen to Rigby 161 kV line are operated radially during summer heavy  
21 loading periods to mitigate the risk of violating NERC Standard TPL-001-4 category  
22 P0 (N-0), P1 (N-1) and P6 (N-1-1) performance requirements due to transmission  
23 capacity deficiencies in the area. Operating radially puts approximately 150



1 megawatts (MW) of load at risk for N-1 loss of either the Goshen to Sugarmill  
2 161 kV line or the Goshen to Rigby 161 kV line and 300 MW at risk for N-1-1 loss of  
3 any two transmission lines.

4 The new Goshen to Sugarmill to Rigby 161 kV line will increase load serving  
5 capacity in the Rigby to Sugarmill area by 250 MVA that will allow the transmission  
6 lines between Goshen, Sugarmill, and Rigby substations to operate in a normal loop  
7 configuration and eliminate N-1 thermal overload and low voltage issues on the  
8 remaining transmission line and substation. Benefits also include elimination of the  
9 N-0 overload risk, improved load service reliability under N-1 conditions, and  
10 resolution of most N-1-1 issues present in the area.

11 **Q. Did PacifiCorp consider alternatives to investing in the Goshen to Sugarmill to**  
12 **Rigby 161 kV Transmission Line?**

13 A. Yes. The first alternative in lieu of the Goshen to Sugarmill to Rigby 161 kV line that  
14 PacifiCorp considered was a project to construct a new approximately 35-mile-long  
15 Goshen to Rigby 345 kV line with 1272 aluminum conductor steel-reinforced  
16 (ACSR) cable and add a new 450 MVA capacity or larger 345/161 kV transformer at  
17 the Rigby substation. Work involved expanding both the Goshen and Rigby  
18 substation yards to accommodate the new facilities consisting of at least two 345 kV  
19 breakers at Goshen, one 345 kV breaker at Rigby and at least two 161 kV breakers at  
20 the Rigby 161 kV substation. This alternative was rejected since the estimated cost of  
21 the project was about \$17.0 million higher than the chosen project to construct the  
22 new Goshen to Sugarmill to Rigby 161 kV transmission line. The alternative was  
23 estimated to be \$57.7 million.

1           A second alternative considered was to construct an approximately 61-mile-  
2 long Antelope to Rigby 161 kV transmission line with 1272 ACSR cable or larger.  
3 Work involved expanding both the Antelope and Rigby substation yards to  
4 accommodate the new facilities consisting of at least two 161 kV breakers at Antelope  
5 and at least two 161 kV breakers at Rigby. A new 161 kV line from Antelope would  
6 provide a new source into the Rigby to Sugarmill area apart from Goshen substation;  
7 however, planning studies indicated that by adding the Antelope to Rigby 161 kV  
8 line, the N-1 loss of the Goshen to Sugarmill 161 kV line would still cause thermal  
9 overload and low voltage issues in the area and that load shedding and radialization of  
10 the Rigby to Sugarmill area would still be required. This alternative was rejected  
11 since the estimated cost of the project was about \$8.0 million higher than the new  
12 Goshen to Sugarmill to Rigby 161 kV transmission line and that a new Antelope to  
13 Rigby 161 kV transmission line does not resolve the loading and voltage issues in the  
14 Rigby to Sugarmill area. The alternative was estimated to be \$48.0 million.

15           A third alternative considered was to construct approximately 22.8 miles of a  
16 161 kV transmission line from the Meadow Creek wind farm substation to Sugarmill  
17 and Rigby substations to create a looped transmission source back to Goshen  
18 substation. Work involved constructing approximately 5.9 miles of new single circuit  
19 161 kV transmission line from Meadow Creek to a new tap location, using the  
20 existing right of way to construct 4.5 miles of double-circuit line from the new tap  
21 location to Sugarmill substation, and construct 12.4 miles of new single-circuit  
22 161 kV line from the new tap location to Rigby substation. Work also included  
23 converting Meadow Creek's 161 kV substation yard into a new three breaker ring

1 bus, installation of at least two 161 kV breakers at Sugarmill and Rigby substations,  
2 rebuilding the Goshen to Wolverine Creek to Jolly Hills to Meadow Creek 161 kV  
3 line with 1557 ACSR cable (approximately 32.4 miles), rebuilding the remaining  
4 three miles of 795 all-aluminum conductor (AAC) cable on the Goshen to Sugarmill  
5 161 kV line, and adding a 161 kV bus tie breaker at Rigby to facilitate sectionalizing  
6 post N-1. Currently, the Goshen wind farms are radial from the Goshen 161 kV  
7 substation. Once looped through the Rigby and Sugarmill substations, a detailed  
8 voltage control study would be required to coordinate the wind farms and shunt  
9 devices in the area. Since the existing radial wind farm line is owned and operated by  
10 third parties, an agreement to use or buy the facilities would need to be negotiated.  
11 This alternative was rejected since the estimated cost of the project was about  
12 \$8.2 million higher than the new Goshen to Sugarmill to Rigby 161 kV transmission  
13 line and required significant coordination with third parties to deliver the project. The  
14 alternative was estimated to be \$48.5 million.

15 The last alternative considered was to loop the existing Goshen to Jefferson  
16 161 kV transmission line in and out of the Bonneville substation. Work involved  
17 converting the Bonneville substation into a 161 kV breaker and one-half  
18 configuration, constructing an approximately 27-mile-long 161 kV line from  
19 Bonneville to Rigby substation with at least 1557 ACSR cable. Work also involved  
20 expanding both the Rigby substation yards to accommodate a new 161 kV line  
21 position consisting of at least two 161 kV breakers at the Rigby substation. Adding  
22 this new Bonneville to Rigby 161 kV line does not improve N-1 and N-1-1 issues in  
23 the area and therefore is not considered as a viable alternative. The estimate for this

1 project was \$33.2 million. Additional projects would be required to address the N-1  
2 and N-1-1 issues. These projects include reconductoring 32 miles of Goshen to  
3 Rigby 161 kV line, reconductoring 16 miles of Sugarmill to Rigby 161 kV line, and  
4 reconductoring 3.5 miles of 795 AAC cable on existing Goshen to Sugarmill  
5 161 kV line. Additionally, a new Goshen to Sugarmill 161 kV line would be required  
6 to mitigate the low voltage and voltage swings caused by the loss of the existing  
7 Goshen to Sugarmill 161 kV line. The estimate to reductor these lines was  
8 \$6.6 million and the estimate to construct a new Goshen to Sugarmill 161 kV line was  
9 \$13.3 million. This alternative was rejected since the estimate for the new Bonneville  
10 to Rigby 161 kV line and supporting projects was about \$12.7 million higher than the  
11 recommended new Goshen to Sugarmill to Rigby 161 kV transmission line project.  
12 The alternative was estimated to be \$53.1 million.

## 13 VI. JORDANELLE TO MIDWAY 138 KV TRANSMISSION LINE PROJECT

- 14 **Q. Please describe the investment for the Jordanelle to Midway 138 kV**  
15 **Transmission Line Project.**
- 16 A. The Jordanelle to Midway 138 kV transmission line project constructed 9 miles of  
17 138 kV transmission line between the Midway and Jordanelle substations in  
18 northwestern Wasatch County Utah. This project also included installation of two  
19 138 kV breakers at Midway substation; the addition of 18 miles of optical ground  
20 wire between Hale and Midway substation; updates of the Naughton remedial action  
21 scheme (RAS); addition of a voltage transformer in Silver Creek and Hale  
22 substations; and protection and control upgrades at affected substations. The line  
23 siting partially followed Heber Light and Power's (HLP) existing 46 kV line across

1 the Heber Valley. The structures are owned by PacifiCorp and, for portions, HLP will  
2 have circuits and other facilities attached to PacifiCorp structures. HLP's paid  
3 contributions in aid of construction for their facilities and Midway City's paid  
4 contribution for excess costs to underground a portion of the line.

5 **Q. Please explain why this investment in the Jordanelle to Midway 138 kV**  
6 **Transmission Line Project is needed and beneficial.**

7 A. In 2011, as part of ongoing contingency and growth studies it was identified that an  
8 outage of the Cottonwood to Snyderville 138 kV line creates a voltage collapse of the  
9 looped Summit and Wasatch County system when the area load is above 190 MW.  
10 The same outage creates voltage below the transmission voltage guideline of  
11 .90 when loading is above 175 MW. In 2020, the area was projected to be above  
12 190 MW for 156 hours and above 175 MW for 620 hours. In addition, Utah  
13 Associated Municipal Power Systems (UAMPS) on behalf of HLP submitted a load  
14 forecast that put them above the system capability under N-1 conditions (loss of the  
15 Hale to Midway 138 kV line) by the year 2019 (approximately 42.9 MW of HLP  
16 load). At the time HLP was served at 46 kV from the Midway substation. An official  
17 request for a 138 kV delivery point was made. HLP plans to install a 138-46 kV  
18 transformer to provide redundancy to their 46 kV system and split HLP's 46 kV load  
19 between the two sources.

1 **Q. Did PacifiCorp consider alternatives to investing in the Jordanelle to Midway**  
2 **138 kV Transmission Line?**

3 A. Yes, an alternative project was to construct a second 138 kV 19-mile line from Hale  
4 substation in Utah County to Midway substation and install a second Midway  
5 138-46 kV 75 MVA transformer. Although a second line from Hale and second  
6 transformer at Midway would raise the system radialization limit to 225 MW, the  
7 138 kV voltage at the Snyderville substation during the loss of the Cottonwood to  
8 Snyderville 138 kV line is the limiting factor. This alternative was rejected due to the  
9 estimated cost coming in higher than the preferred option and the resulting  
10 radialization limit was 20 MW lower than the preferred option. In addition, the  
11 construction and permitting of a new 138 kV line through Provo Canyon was deemed  
12 to be more difficult.

## 13 **VII. CONCLUSION**

14 **Q. Please summarize your recommendation to the Commission.**

15 A. I recommend that the Commission determine that the projects stated above will  
16 provide benefits to Oregon customers and are therefore prudent and in the public  
17 interest.

18 **Q. Does this conclude your direct testimony?**

19 A. Yes.

Docket No. UE 399  
Exhibit PAC/601  
Witness: Richard A. Vail

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

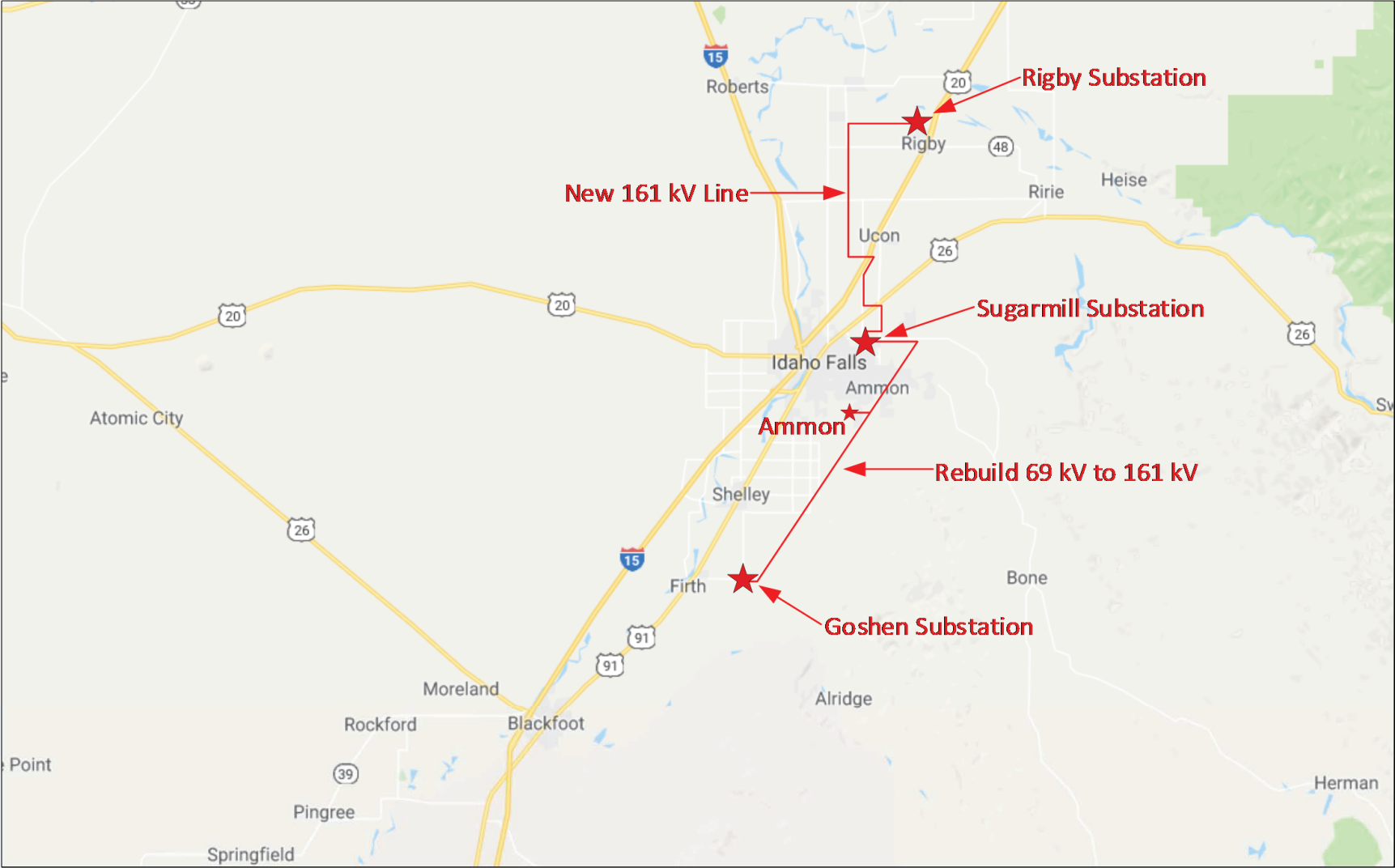
**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Richard A. Vail  
Goshen to Sugarmill to Rigby 161 kV Transmission Line Project**

**March 2022**

# Goshen-Sugarmill-Rigby 161 KV Transmission Line Project Area





Docket No. UE 399  
Exhibit PAC/602  
Witness: Richard A. Vail

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

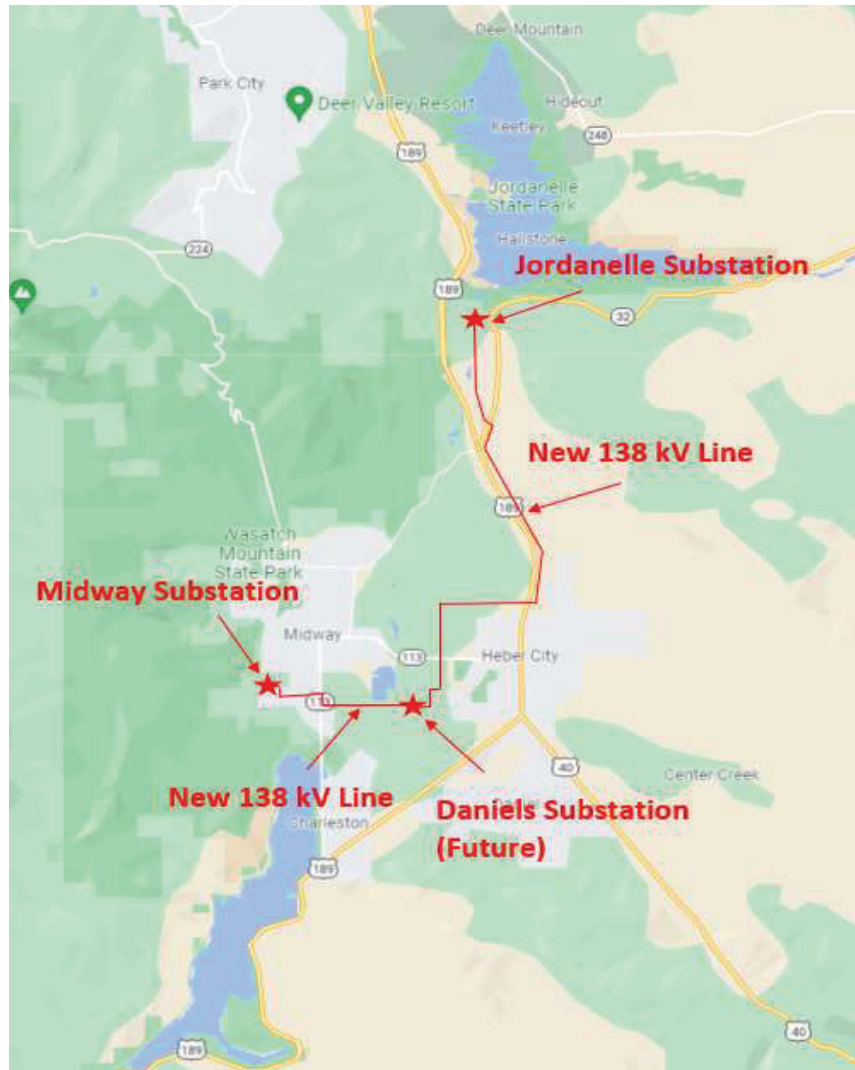
**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Richard A. Vail  
Jordanelle to Midway 138 kV Transmission Line Project**

**March 2022**

## Jordanelle-Daniels-Midway 138 KV Transmission Line Project Area



Docket No. UE 399  
Exhibit PAC/700  
Witness: Allen Berreth

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Direct Testimony of Allen Berreth**

**March 2022**

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## ATTACHED EXHIBITS

Exhibit PAC/701—PacifiCorp Service Territory with FHCA

1                                   **I.    INTRODUCTION AND QUALIFICATIONS**

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

4    A.    My name is Allen Berreth. My business address is 825 NE Multnomah Street, Suite  
5        1700, Portland, Oregon 97232. My present position is Vice President of  
6        Transmission and Distribution Operations for PacifiCorp. I am responsible for the  
7        departments that support the operations, maintenance, and construction of  
8        PacifiCorp’s transmission and distribution systems; such as Asset Management,  
9        Investment Delivery, Finance, Real Estate, GIS, Facilities, Vegetation Management,  
10       and Wildfire Mitigation Planning.

11 **Q.    Briefly describe your education and professional experience.**

12 A.    I have a Bachelor of Science degree in Electrical Engineering with a focus in electric  
13       power systems from the University of Idaho and a Masters of Business  
14       Administration from Utah State University. I have been Vice President of  
15       Transmission and Distribution Operations since October 2020. Prior to my current  
16       position, I have held positions in delivery assurance, asset management, work  
17       planning, business improvement, and field engineering since joining PacifiCorp in  
18       1998.

19 **Q.    Have you testified in previous regulatory proceedings?**

20 A.    Yes, I have testified previously in Washington.

21                                   **II.    PURPOSE OF TESTIMONY**

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

23 A.    The purpose of my testimony is to describe PacifiCorp’s wildfire related

1 transmission and distribution investments and vegetation management expenses  
2 included in this rate case. I support the Company's incremental investments in  
3 wildfire mitigation to address the risks posed by the increased frequency, severity,  
4 and costs of wildfires to customers, employees, and Company facilities. My  
5 testimony also supports an increase to baseline vegetation management spend due to  
6 cost escalations, and proposes changes to the Wildfire Mitigation and Vegetation  
7 Management Cost Recovery Mechanism (WMVM) to improve its effectiveness and  
8 functionality. I recommend that the Commission approve these new investments and  
9 proposed changes as prudent and in the public interest.

### 10 III. BACKGROUND ON WILDFIRE RISK IN OREGON

11 **Q. How have the risks associated with wildfires evolved in PacifiCorp's service**  
12 **territories?**

13 A. There has always been some degree of wildfire risk across PacifiCorp's service  
14 territories, including in Oregon. This risk is inherent to operating an electric utility  
15 and is elevated for utilities in the Western United States where climates are arid year-  
16 long in some areas, or seasonally in others. However, the frequency, severity, and  
17 costs of catastrophic wildfires are increasing across the West. Recent experiences  
18 with catastrophic and tragic wildfires have resulted in an even greater focus on  
19 wildfire risk mitigation by public utilities in the region.

20 **Q. Please describe Senate Bill (SB) 762 and the Wildfire Protection Plans (WPPs).**

21 A. On July 19, 2021, Governor Brown signed SB 762 into law. SB 762 requires that  
22 public utilities file with the Commission risk-based WPPs that include means for  
23 mitigating wildfire risk, balancing costs with the resulting reduction of risk, and

1 preventive actions and programs to minimize risk of utility facilities causing a  
2 wildfire.<sup>1</sup> This law allows for recovery of all reasonable costs and prudent  
3 investments made by a public utility to implement a WPP and also allows for the  
4 recovery of those costs through an automatic adjustment clause.<sup>2</sup> PacifiCorp filed its  
5 WPP on December 30, 2021.

6 **Q. What are the elements of the WPP?**

7 A. PacifiCorp is adapting to the changes in wildfire risk through adoption of accelerated  
8 and enhanced wildfire mitigation measures that conform with Oregon legislation,  
9 including SB 762, for utility wildfire mitigation. PacifiCorp identified key goals to  
10 help inform its wildfire mitigation approach: 1) minimize the risk of wildfires from  
11 PacifiCorp equipment; 2) promptly address any problems attributed to PacifiCorp  
12 equipment if they do occur; 3) be prepared to address wildfires from other sources;  
13 and 4) respond when a wildfire puts utility equipment at risk. PacifiCorp took these  
14 goals and engaged in an extensive modeling process to develop a risk-based approach  
15 to achieving them. This risk-based approach facilitates smart investments targeted to  
16 places on PacifiCorp's system where they will have the most impact and ensures that  
17 PacifiCorp's human capital is also deployed in areas where they will have the greatest  
18 impact. These targeted investments are incremental to PacifiCorp's investment in the  
19 ordinary course of its business and will meaningfully reduce the wildfire risk on the  
20 Company's system.

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<sup>1</sup> See ORS 757.963.

<sup>2</sup> ORS 757.963(8).

1 **Q. Please describe how the risk of wildfire has been modeled in PacifiCorp's service**  
2 **territory.**

3 A. PacifiCorp recognizes that if certain weather and fuel conditions are present, a  
4 disruption of normal operations on the electrical network, called a "fault", can result  
5 in the ignition of a fire. Under certain weather conditions and in the vicinity of  
6 wildland fuels, such an ignition can grow into a harmful wildfire, potentially even  
7 growing into a catastrophic wildfire causing great harm to people and property.  
8 PacifiCorp's risk analysis reviews fire history, the recorded causes of the fires, the  
9 acreage impact of the fires, and when in the year the fires typically occur. Using that  
10 information, the risk analysis identifies the logic for a risk-informed method to  
11 strategically address utility wildfire risks. PacifiCorp patterned its wildfire risk  
12 modeling on the methodology developed after a long and iterative process in  
13 California. To take advantage of the experience learned through that process,  
14 PacifiCorp engaged REAX Engineering Inc., a fire-science engineering firm, to  
15 identify areas of elevated wildfire risk, designated as Fire High Consequence Areas  
16 (FHCA).

17 The data and process used in PacifiCorp's analysis are as follows:

- 18 1) Topography of the land, including elevation, slope, and aspect;  
19 2) Fuel data which quantify fuel loading, fuel particle size, and other  
20 quantities needed by fire models to calculate the rate of spread;  
21 3) Weather Research and Forecasting, which is a hybrid of weather  
22 modeling and surface weather observations (including temperature,  
23 relative humidity, wind speed/direction, and precipitation);



- 1           4) Historical fire weather days spanning the period from January 1,
- 2                   1979, through December 31, 2017;
- 3           5) Estimated live fuel moisture;
- 4           6) Ignition modeling, using Monte Carlo simulated ignition scenarios;
- 5                   and
- 6           7) Fire spread modeling.

7           In addition, potential impact was considered by factoring population density.

8           In general, if population density did not correlate to fuel and fire weather history, an  
9           area would not be considered a candidate for FHCA designation. A final confirmation  
10          exercise was completed by evaluating the FHCA against historical fire perimeters  
11          (which are the final recorded footprint for any given fire), existing Company facility  
12          equipment, and the Company's service territories. The resulting FHCA and  
13          PacifiCorp's service territories are shown in Exhibit PAC/701.

14   **Q.   Based on this wildfire risk modeling, what components of PacifiCorp's system**  
15   **have been identified as existing in a FHCA?**

16   A.   Based on the wildfire risk modeling conducted in PacifiCorp's service area, a large  
17   portion of PacifiCorp's service territory in southern Oregon, northern California and  
18   parts of Washington and Utah are identified as having sections inside the FHCA and  
19   are candidates for wildfire mitigation project investments.

1                                    **IV.    WILDFIRE MITIGATION CAPITAL COSTS**

2   **Q.    What are the planned capital costs for the wildfire mitigation projects in 2021**  
3   **and 2022?**

4   **A.    Table 1 below describes the specific wildfire mitigation capital costs by breakdown of**  
5   **activity.**

1

**Table 1: Wildfire Mitigation System Hardening Program Capital Costs\***

<b>Investment Category</b>	<b>Mitigation Program(s) Included</b>	<b>Description of Program</b>	<b>Purpose/Risk Being Mitigated</b>	<b>Planned Capital Costs through 2022</b>
Oregon Distribution	System Hardening: Line Rebuild	Distribution line rebuilds including all or parts of the following: installation of covered conductor, transition to underground, pole replacements, and conductor replacements	Reduce equipment failure that may ignite a wildfire along with increased resiliency to a wildfire occurrence	\$27,237,149
	System Hardening: Advanced Protection & Control	Replace electro-mechanical relays protecting distribution lines in FHCA with modern microprocessor relays that provide more accurate data and faster relaying	Increasing ability to locate where a fault occurred on a line which could result in increased patrol time	
	System Hardening: Pole mounted overcurrent and overvoltage protection replacement	Replacement of fuses, lightning arrestors and cutouts throughout the FHCA with non-expulsion type equipment	Reduce equipment failure that may ignite a wildfire along with increased resiliency to a wildfire occurrence	
Transmission	System Hardening: Line Rebuild	Transmission line rebuilds including all or parts of the following: installation of covered conductor, tree wire, pole replacement, and conductor replacements	Reduce equipment failure that may ignite a wildfire along with increased resiliency to a wildfire occurrence	\$7,443,032
Oregon Situs	Situational Awareness	Invest in tools, software, and hardware to incorporate real time weather data, implement a risk forecasting and impact-based fire weather model, and inform key decision making and protocols.	Develop a dynamic risk assessment tool to inform investment scenarios, initiative prioritization, and overall decision making to manage risk	\$1,700,000 <sup>3</sup>
<b>Total</b>				<b>\$36,380,181</b>

\*Transmission costs provided reflect the Oregon allocation of total-company costs.

<sup>3</sup> Capital investment in situational awareness will be recovered through the deferral accounting requested in the Company's application in Docket No. UM 2221 instead of this general rate case filing.

1 I discuss these mitigation programs included in system hardening and situational  
2 awareness in more detail below.

3 **A. System Hardening**

4 **Q. Please explain what system hardening is in the context of the Company's wildfire  
5 mitigation efforts.**

6 A. System hardening is an engineered response to an identified risk to the electrical  
7 system. System hardening includes retrofitting specific devices or components within  
8 the system to make it more resilient and may also include the wholesale replacement  
9 of legacy equipment when retrofitting is not a viable solution. I will describe some of  
10 the system hardening that PacifiCorp is and will be engaging in to mitigate wildfire  
11 risks in more detail below.

12 **Q. How do these system hardening projects reduce the threat of wildfire?**

13 A. PacifiCorp's system hardening projects focus on reducing the potential that the power  
14 system is the source of ignition by creating a spark during a fault event. A significant  
15 ignition driver on electrical systems is contact from foreign objects (trees, wildlife,  
16 mylar balloons, etc.) that can result in high-energy and high-temperature arcing  
17 between two conductors or between one conductor and the ground.

18 **Q. What hardening efforts on distribution systems reduce potential ignitions?**

19 A. All of the Company's wildfire mitigation programs applied to distribution systems  
20 work to either prevent ignitions or control the potential events to limit overall impact.  
21 The key programs included in system hardening of distribution systems include the  
22 line rebuild project, implementation of advanced protection and control schemes

1 through equipment upgrades, and the replacement of pole mounted overcurrent and  
2 overvoltage protection equipment such as expulsion fuses.

3 **B. Line Rebuild Program**

4 **Q. Please explain what the line rebuild program is in the context of wildfire**  
5 **mitigation.**

6 A. A key hardening effort for wildfire mitigation is the line rebuild program where  
7 targeted lines or portions of lines are either moved, removed, transitioned to  
8 underground, or retrofitted with more resilient materials such as covered conductor to  
9 mitigate the risk of contact related faults on overhead conductor. Currently, the  
10 majority of the program includes retrofitting existing lines with covered conductor.  
11 Covered conductor, unlike bare conductor, is designed to withstand incidental contact  
12 with vegetation, other debris, and even the ground in a wire down event. The  
13 program will involve more than replacing existing bare conductor with covered  
14 conductor. Poles will be replaced as necessary based on loading assessments of  
15 existing poles where covered conductor is to be installed. This is because covered  
16 conductor is heavier than bare conductor and, under the combination of ice and wind,  
17 has a larger diameter which results in further additional pole loading. A secondary  
18 benefit to covered conductor is an improvement in reliability. In certain applications  
19 standard pole mounted overcurrent and overvoltage protection equipment, such as  
20 fuses, lightning arrestors, and cutouts, will be replaced within the FHCA with non-  
21 expulsion type equipment to eliminate any melted fuse material from falling to the  
22 ground when operated.

1 **Q. Is it standard practice for PacifiCorp to install covered conductor, non-expulsion**  
2 **fuses, or composite material distribution poles?**

3 A. No. Standard overhead circuit construction uses bare conductor and wood poles that  
4 balance safety, reliability, and costs. The installation of covered conductor, non-  
5 expulsion fuses, and composite material poles are in direct response to increased  
6 wildfire risk and are specifically designed to accelerate and improve mitigation of  
7 catastrophic wildfires associated with PacifiCorp's system.

8 **Q. How do transmission line rebuilds help mitigate and protect against wildfire**  
9 **risk?**

10 A. Rebuilding transmission lines helps to reduce equipment failures and incidental  
11 contacts that pose a risk of wildfire ignition. Such equipment failures, while  
12 infrequent occurrences, could result in substantial arc energy that can result in  
13 wildfire ignition. Due to the cross-country nature of many portions of PacifiCorp's  
14 system (particularly on the local transmission network) the risk of ignition sources is  
15 heightened. For example, in Oregon, trees outside of the vegetation managed  
16 corridors that are particularly tall, or located on slopes, result in increased risk of fall-  
17 in contacts. Rebuilding transmission lines in areas where this risk is heightened  
18 allows PacifiCorp to install covered conductor and improve structures. Respectively,  
19 such measures will reduce the probability of a fault event and improve resiliency to  
20 the extent rebuilt structures can better withstand localized wildfire events.

21 **Q. What criteria did the Company use to select areas in the FHCA to replace**  
22 **existing conductor with covered conductor?**

23 A. PacifiCorp targeted areas within the FHCA to determine what areas in its system were

1 at elevated risk based on proximity to population centers, historic weather patterns,  
2 and vegetation. Covered conductor was selected for use where there is risk of  
3 incidental contacts, such as large branches or trees striking the phase conductors.

4 **Q. Are there reliable measurements or metrics the Company can use to determine**  
5 **how successful the use of covered conductor is in mitigating wildfire risks over**  
6 **time?**

7 A. Yes, although such measurements will not be immediately informative. Over time,  
8 the Company anticipates that comparisons of fault rates resulting from incidental tree  
9 contacts for the areas where covered conductor is employed versus the same areas  
10 before replacement with the covered conductor will demonstrate the effectiveness of  
11 this measure.

12 **Q. What kind of monitoring does the Company plan to use to ensure that the use of**  
13 **covered conductor is meeting expectations in the absence of such metrics?**

14 A. As noted in my response to the preceding question, the Company will track fault rates  
15 resulting from incidental tree contacts on rebuilt sections. This information will  
16 enable the Company to compare faults both before and after installation of covered  
17 conductor to better understand how successful it has been in mitigating wildfire risks  
18 over time. Unfortunately, the data needed to quantitatively provide useful metrics for  
19 such a comparison will not be available for several years.

20 **C. Advanced Protection and Control**

21 **Q. Please explain what advanced protection and control measures are in the context**  
22 **of wildfire mitigation.**

23 A. Advanced protection involves the deployment of sophisticated protection control

1 strategies, particularly advanced relay technologies on distribution and transmission  
2 lines. In the context of wildfire risk mitigation, these protection control strategies  
3 involve the device operations that take place when fault events occur. In contrast to  
4 the wildfire mitigation strategies discussed above, which relate to limiting the  
5 occurrence of fault events, advanced protection and control strategies relate to  
6 limiting the length and magnitude of a fault event. Specifically, the window of time  
7 after fault events represents the time when electrical system facilities pose the highest  
8 risk of igniting adjacent fuel, which could result in a wildfire. Reducing the time  
9 between when a fault occurs and that fault condition is cleared may reduce the risk of  
10 igniting adjacent fuel.

11 **Q. Please describe the differences between legacy electro-mechanical relays and**  
12 **modern microprocessor relays.**

13 A. Unlike an electro-mechanical relay, microprocessor relays are able to exercise  
14 programmed functions nearly immediately (near the speed of light), which results in  
15 much faster device response during fault conditions. Microprocessor relays also  
16 allow for greater customization to address environmental conditions through multiple  
17 settings groups; they are also better able to incorporate complex logic to execute  
18 specific operations. Also, in contrast to electro-mechanical relays, microprocessor  
19 relays retain event logs that provide data for fault location and later analysis.



1 **Q. Will these modern microprocessor relays provide the Company more data**  
2 **regarding line contacts and other faults on the system than the electro-**  
3 **mechanical relays currently used on PacifiCorp's system?**

4 A. Yes. These new relays will capture a variety of event logs, including waveforms  
5 during fault events.

6 **Q. How will the additional data provided by these new relays help the Company in**  
7 **its wildfire mitigation efforts?**

8 A. In addition to faster fault clearing schemes, these relays improve response times since  
9 they can identify locations where disturbances emanate from, which will be used by  
10 field and office teams to assess these situations. PacifiCorp will also use this data  
11 during investigations of events to ensure that the devices performed consistent with  
12 the programmed settings and to evaluate other wildfire mitigation technologies.

13 **D. Replacement of Pole Mounted Overcurrent and Overvoltage Protection**  
14 **Equipment**

15 **Q. Please explain what the replacement of pole mounted overcurrent and**  
16 **overvoltage protection equipment means in the context of wildfire mitigation.**

17 A. The replacement of pole mounted overcurrent and overvoltage protection equipment  
18 includes the proactive replacement of all expulsion type fuses, lightning arrestors, and  
19 cutouts in the FHCA.

20 **Q. Is it standard practice to use non-expulsion type fuses and lightning arrestors?**

21 A. No. Non-expulsion type fuses and lightning arrestors are not standard practice.

1 **Q. How does the replacement of expulsion type fuses and lightning arrestors help**  
2 **mitigate and protect against wildfire risk**

3 A. Overhead expulsion fuses serve as one of the primary system protection devices on  
4 the overhead system. The expulsion fuse has a small metal element within the fuse  
5 body that is designed to melt when excessive current passes through the fuse body,  
6 interrupting the flow of electricity to the downstream distribution system. Under  
7 certain conditions, the melting action and interruption technique will expel an arc out  
8 of the bottom of the fuse tab. To reduce the potential for ignition as a result of fuse  
9 operation, PacifiCorp has identified alternate methodologies and equipment that do  
10 not expel an arc for installation within the FHCA.

11 **E. Situational Awareness**

12 **Q. Please explain what situational awareness is in the context of the Company's**  
13 **wildfire mitigation efforts.**

14 A. Having a sophisticated, dynamic risk model grounded in situational awareness is  
15 pertinent to ensure electric utilities know when, where, how, and why to take action to  
16 mitigate the risk of wildfire. PacifiCorp's approach to situational awareness includes  
17 the acquisition of data to run real time, daily simulations, forecast and assess the risk  
18 of potential or active events to inform operational strategies, response to local  
19 conditions, and influence decision making. Decision making could include the  
20 implementation of augmented protection and control schemes or activation of  
21 additional resources for supplemental patrols to assess local conditions.

1 **Q. What key investments need to be made to support this approach toward**  
2 **situational awareness?**

3 A. To support the development of a robust, repeatable, dynamic risk assessment tool, a  
4 combination of investments must be made including the acquisition of data, collection  
5 of company owned data through new devices, storage and processing of data, and  
6 mapping or visualization of data into dashboards and tools. Software, hardware, data  
7 storage, data management, and data processing tools must be purchased to move  
8 forward an enterprise type solution with built in redundancy.

9 **Q. What capital expenditures overall will the Company make through 2022 with**  
10 **respect to system hardening and situational awareness?**

11 A. As shown in Table 1, through 2022, PacifiCorp will make capital expenditures of  
12 approximately \$27,237,149 in its Oregon distribution system and \$7,443,032 Oregon-  
13 allocated in its transmission system on system hardening. The additional situational  
14 awareness investment of \$1,700,000 (Oregon allocated) is not included in this filing  
15 and will be recovered through the Company's WPP deferral request in docket UM  
16 2221.

17 **Q. Please describe the benefits of PacifiCorp's wildfire mitigation investments.**

18 A. Proactively investing in wildfire mitigation projects in identified FHCAs reduces the  
19 risk of catastrophic fire caused by PacifiCorp's facilities, directly benefiting  
20 PacifiCorp customers. In addition, reducing the risk of catastrophic fire benefits fire  
21 response agencies, preserves customer property and Company facilities, and  
22 minimizes the cost of rebuilding.

1 **Q. How do PacifiCorp's wildfire mitigation efforts relate to the Company's**  
2 **standard safety and compliance activities?**

3 A. Many of the wildfire mitigation strategies I discuss above go beyond standard utility  
4 practice. For example, PacifiCorp does not, in the normal course, install covered  
5 conductor. These measures are in direct response to changing best practices for  
6 mitigating wildfire and are incremental to work PacifiCorp would do in the ordinary  
7 course of its business. Similarly, activities such as replacement of existing equipment  
8 (replacing distribution poles with composite material poles, replacing electro-  
9 mechanical relays, etc.) are now informed by the potential for the replacement to  
10 mitigate wildfire risk, location of the existing equipment within FHCA, and may  
11 involve accelerated replacements.

12 **V. WILDFIRE MITIGATION INCREMENTAL EXPENSE**

13 **Q. Are the capital investments described above the only type of investments being**  
14 **made in Oregon to mitigate wildfire risk?**

15 A. No. As mentioned above, PacifiCorp filed its first WPP on December 30, 2021. This  
16 plan reflects a comprehensive approach to mitigating the risk of wildfires and  
17 includes increased capital investment as well as operating expense to move forward  
18 critical maintenance programs. Table 2 below describes the specific incremental  
19 wildfire mitigation expense planned in 2023 by breakdown of activity due to an  
20 increase in scope above legacy programs.

1 **Table 2: Wildfire Mitigation System Hardening Program Incremental Annual Expense**

<b>Investment Category</b>	<b>Programs / Incremental Scope Included</b>	<b>2023 Planned Spend Total Co. (\$) <sup>4</sup></b>	<b>2023 Planned Spend OR Alloc. (\$) <sup>5</sup></b>
WMP Transmission (Non-Vegetation Management)	<ul style="list-style-type: none"> <li>• Annual asset inspections in the FHCA</li> <li>• Annual Enhanced Inspections (Infrared) inspections in the FHCA</li> </ul>	\$148,000	\$38,584
WMP Distribution (Non-Vegetation Management)	<ul style="list-style-type: none"> <li>• Annual asset inspections in the FHCA</li> <li>• Transition from a 10-yr to a 5-yr detail inspection cycle in the FHCA (100% increase in annual detailed inspections)</li> <li>• Situational awareness (Described above in testimony)</li> <li>• Stakeholder and community engagement</li> <li>• Plan monitoring</li> </ul>	\$4,207,676	\$4,207,676
WMP Vegetation Management - Transmission	<ul style="list-style-type: none"> <li>• Annual vegetation management inspections in the FHCA</li> <li>• Implementation of new maintenance cycles</li> </ul>	\$470,636	\$124,261
WMP Vegetation Management - Distribution <sup>5</sup>	<ul style="list-style-type: none"> <li>• Annual vegetation management inspections in the FHCA</li> <li>• Radial pole clearing of subject poles in the FHCA</li> <li>• Implementation of new maintenance cycles</li> </ul>	\$15,289,309	\$15,289,309
<b>TOTAL</b>		<b>\$20,121,621</b>	<b>\$19,659,830</b>

2 **A. Asset Inspections**

3 **Q. How do asset inspections mitigate wildfire risk?**

4 A. Inspection and correction programs are the cornerstone of a resilient system. These  
5 programs are tailored to identify conditions that could result in premature failure or  
6 potential fault scenarios, including situations in which the infrastructure may no

<sup>4</sup> Planned incremental wildfire mitigation spend in this table includes Oregon’s allocation only but reflects the same planned spend and programs included in PacifiCorp’s 2022 WPP.

<sup>5</sup> This spend is not due to escalation of existing vegetation management costs but is incremental spend due to increased scope and activities.

1 longer be able to operate per code or engineered design, or may become susceptible  
2 to external factors, such as weather conditions. The existing inspection and  
3 correction programs are effective at maintaining regulatory compliance and managing  
4 routine operational risk. They also mitigate some wildfire risk by identifying and  
5 correcting conditions which, if uncorrected, could potentially ignite a fire.

6 Recognizing the growing risk of wildfire, PacifiCorp is supplementing its existing  
7 programs to further mitigate the growing wildfire specific operational risks and create  
8 greater resiliency against wildfires. These changes are meant to increase the  
9 frequency of inspections or how assets are inspected to accelerate identification and  
10 correction of conditions.

11 **Q. What are these specific changes?**

12 A. PacifiCorp's asset inspection program involves three primary types of inspections:  
13 (1) visual assurance inspection; (2) detailed inspection, and (3) pole test & treat.  
14 Legacy inspection cycles, which dictate the frequency of inspections, are set by  
15 PacifiCorp asset management to align with state specific compliance requirements.  
16 In general, visual assurance inspections are conducted more frequently, to quickly  
17 identify any obvious damage or defects that could affect safety or reliability. Detailed  
18 inspections have a more detailed scope of work, so they are performed less frequently  
19 than visual assurance inspections. The frequency of pole test & treat is based on the  
20 age of wood poles, and such inspections are typically scheduled in conjunction with  
21 certain detailed inspections. Regarding distribution, PacifiCorp is proposing to move  
22 from a two-year cycle to an annual frequency for visual assurance inspection in the  
23 FHCA and from a 10-year cycle to a five-year cycle for detailed inspections in the

1 FHCA, effectively increasing the number of each type of inspection annually in the  
2 FHCA by 100 percent over legacy programs. PacifiCorp also plans to introduce new,  
3 annual enhanced inspections annually on overhead transmission in the FHCA.

4 **Q. What are enhanced inspections?**

5 A. PacifiCorp's enhanced inspection utilizes alternate technologies to identify hot spots,  
6 equipment degradation, and potentially substandard connections that are not  
7 detectable through a visual inspection. Infrared data is gathered using a helicopter  
8 flying over the designated lines within the FHCA near peak loading intervals and is  
9 performed incrementally to existing inspection programs.

10 **Q. How do these enhanced inspections mitigate wildfire risk?**

11 A. Hot spots on power lines identified through infrared data gathering can be indicative  
12 of loose connections, deterioration, and/or potential future fault locations. Therefore,  
13 identification and removal of hot spots on overhead transmission lines can prevent  
14 further deterioration, reduce the potential for equipment failure and faults, and reduce  
15 ignition probability related to equipment failure.

16 **Q. Are asset inspections the only proposed change to mitigate wildfire risk?**

17 A. No. PacifiCorp is also proposing enhancing programs in the areas of situational  
18 awareness, which is already described above in my testimony, stakeholder and  
19 community engagement, plan monitoring, and vegetation management.

1           **B.     Stakeholder and Community Engagement**

2   **Q.     What is stakeholder and community engagement in the context of wildfire**  
3   **mitigation?**

4   A.     PacifiCorp plans to employ a multi-pronged approach for community engagement  
5           and outreach with the goal of providing clear, actionable, and timely information to  
6           customers, community stakeholders, public safety partners, and regulators. Over the  
7           past several years, the Company has engaged customers and the general public on the  
8           topic of wildfire safety and preparedness through a variety of tactics and intends to  
9           continue enhancing this outreach including webinars, in-person forums, targeted paid  
10          media campaigns, press engagement, distributed print materials, social media  
11          updates, and communication through owned channels such as bill messages and  
12          website content, among others. Regarding coordination with public safety partners,  
13          PacifiCorp plans to continue implementing tabletop and function exercises to  
14          enhanced collaboration and prepare for emergencies.

15                 Overall, the wildfire safety and preparedness community and stakeholder  
16                 engagement plan will continue to mature year-over-year as additional feedback and  
17                 regulatory guidance is incorporated to broaden engagement and outreach outside of  
18                 traditional engagement methods.

19           **C.     Plan Monitoring**

20   **Q.     How does incremental plan monitoring reduce the risk of wildfires?**

21   A.     As previously stated in my testimony, PacifiCorp's WPP reflects a comprehensive  
22           approach to mitigating the risk of wildfires and impacts many programs and  
23           departments across the Company. To successfully deliver the plan and obtain the plan



1 objectives of reducing wildfire risk, additional resources are needed to develop,  
2 implement, and monitor the plan and the various programs or projects included.  
3 Specific examples include meteorologists, emergency managers, program managers,  
4 program controllers, and analysts to name a few. These key resources are critical to  
5 ensuring the timely and quality completion of the program elements such as  
6 community outreach, public safety partner coordination and planning, situational  
7 awareness, asset inspections, and vegetation management.

8 **D. Wildfire Mitigation Vegetation Management**

9 **Q. How does vegetation management relate to reducing wildfire risks?**

10 A. Vegetation management is generally recognized as a significant strategy in any WPP.  
11 Vegetation contacting a power line is a potential source of fire ignition. Thus,  
12 reducing vegetation contacts reduces the potential of an ignition originating from  
13 electrical facilities. While it is impossible to eliminate vegetation contacts  
14 completely, at least without radically altering the landscape near power lines, a  
15 primary objective of PacifiCorp's existing vegetation management program is to  
16 minimize contact between vegetation and power lines by addressing grow-in and fall-  
17 in risks. This objective is in alignment with core WPP efforts, and continuing  
18 dedication to administering existing programs is a solid foundation for PacifiCorp's  
19 WPP efforts. To supplement the existing program, PacifiCorp vegetation  
20 management is implementing additional WPP strategies in Oregon.

21 **Q. What are these strategies being implemented?**

22 A. The focus of PacifiCorp's vegetation management efforts generally includes pruning  
23 and tree removals. PacifiCorp prunes trees to maintain a safe distance between tree

1 limbs and power lines. PacifiCorp also removes trees that pose an elevated risk of  
2 falling into a power line. In Oregon, this has traditionally been completed on  
3 distribution facilities with a four-year cycle. To address the growing risk of wildfires  
4 in Oregon, PacifiCorp plans to transition to a three-year cycle for all vegetation  
5 management work.

6 In addition to the transition to a three-year cycle discussed above, PacifiCorp's  
7 vegetation management specifically targets risk reduction in the FHCA with three  
8 distinct strategies. First, PacifiCorp vegetation management will conduct annual  
9 vegetation inspections on all lines in the FHCA, with correction work also completed  
10 based on inspection results. Second, PacifiCorp will use increased minimum  
11 clearance distances for distribution cycle work completed in the FHCA. Third,  
12 PacifiCorp plans to complete annual pole clearing on subject equipment poles located  
13 in the FHCA.

14 **Q. How does this compare to PacifiCorp's existing or legacy vegetation**  
15 **management program?**

16 A. Prior to the development of the WPP, PacifiCorp already had a vegetation  
17 management program in place. While the legacy program contained similar elements  
18 and objectives to the strategies just described, the incremental efforts reflect a shift  
19 change in strategy and the costs reflect the incremental spend needed to accomplish  
20 the new tasks and work to meet the objectives of the increase in scope. As such, it  
21 should be viewed as incremental to baseline or legacy vegetation management  
22 programs.

1 **Q. How is PacifiCorp proposing to change that mechanism in light of the recently**  
2 **passed legislation on WPPs?**

3 A. As discussed below, PacifiCorp is proposing to modify that mechanism so it will only  
4 cover vegetation management costs. PacifiCorp will not recover future wildfire  
5 mitigation costs through that mechanism, but instead will propose a new mechanism  
6 in the future consistent with the requirements of SB 762 for the recovery of those  
7 costs. Please refer to the testimony of Company witness Ms. Joelle R. Steward for a  
8 more detailed explanation of SB 762 and the changes to the WMVM.

9 **VI. VEGETATION MANAGEMENT**

10 **A. Increases in Baseline Vegetation Management Costs**

11 **Q. Is PacifiCorp proposing an increase in baseline vegetation management costs?**

12 A. Yes. Additional spending has been identified for the legacy vegetation management  
13 due to cost escalation and change in program activities. Different than the wildfire  
14 mitigation spending, which reflects an increase in scope to accomplish additional  
15 work within the FHCAs and reduce the risk of wildfire, this spend has been identified  
16 due to the increase in costs experienced to accomplish the core work of the program,  
17 including the shift to a three-year cycle. PacifiCorp's forecast costs in this case  
18 reflect updates to the expenses PacifiCorp has seen over the past year to meet its  
19 vegetation management goals and reflect the ongoing cost to implement PacifiCorp's  
20 vegetation management program outside the scope of the wildfire mitigation spending  
21 covered under SB 762 implementation.

1 **Q. Can you provide some examples of what is driving the increased costs for**  
2 **PacifiCorp's vegetation program?**

3 A. Similar to the wildfire vegetation management discussion above, the focus of  
4 PacifiCorp's vegetation management efforts generally includes pruning and tree  
5 removals. PacifiCorp prunes trees to maintain a safe distance between tree limbs and  
6 power lines. PacifiCorp also removes trees that pose an elevated risk of falling into a  
7 power line. In Oregon, this has traditionally been completed on distribution facilities  
8 with a four-year cycle. To address the growing risk of wildfires in Oregon,  
9 PacifiCorp plans to transition to a three-year cycle for all vegetation management  
10 work. The volume of tree removals that pose an elevated risk of falling into a power  
11 line has also increased in recent years, which has increased the associated costs. In  
12 addition, increased labor costs have also been experienced as the market for  
13 vegetation management workers has become more competitive. This has not only  
14 increased the base labor costs for the vegetation management program as a whole but  
15 has also increased costs for labor premiums to attract additional travel crews to the  
16 area.

17 **Q. What is the impact of these increased costs on the operation and maintenance**  
18 **(O&M) included for vegetation management in base rates?**

19 A. PacifiCorp is proposing to increase baseline O&M for vegetation management from  
20 \$30 million to \$50 million.

21 **Q. Despite this cost increase, what steps is the Company taking to control costs**  
22 **while still achieving the goals of the program?**

23 A. PacifiCorp is implementing two strategies for cost control and delivering on the goals

1 of the vegetation management program as described above. The first strategy is  
2 increasing the number of internal company foresters that coordinate the vegetation  
3 management activity within a geographic area. This will increase oversight of both  
4 program efficiencies and deliverables. The second strategy is implementing an  
5 internal vegetation management audit team that will bolster the quality assurance  
6 reviews of the program. This will also help drive program performance in terms of  
7 productivity, efficiency, and cost of program deliverables.

8 **B. Changes to the WMVM**

9 **Q. Please describe the WMVM that was approved in PacifiCorp's last general rate**  
10 **case as it relates to wildfire mitigation.**

11 A. The WMVM provides for the possible recovery of prudent wildfire mitigation and  
12 vegetation management costs between rate cases through a separate recovery  
13 mechanism. Under the mechanism, PacifiCorp would be allowed to recover up to  
14 \$6.6 million in wildfire mitigation and vegetation management costs over what was  
15 included in base rates based on the number of probable violations identified in the  
16 subsequent years vegetation audit and the company's earnings. The audit would  
17 cover all of PacifiCorp's Oregon system, not just those lines that were worked the  
18 year before, or since the mechanism was created. PacifiCorp would have to have  
19 fewer than 75 probable violations in the subsequent year audit to recover its costs,  
20 unless the Company is significantly underearning. PacifiCorp, however, could  
21 recover expenses above the incremental \$6.6 million based on a less restrictive  
22 earnings test and larger violation criteria.

1 **Q. Is PacifiCorp proposing changes to the WMVM?**

2 A. Yes, PacifiCorp is proposing revisions to improve the operation of the WMVM with  
3 regards to vegetation management. There are two main reasons behind PacifiCorp's  
4 proposal. First, the WMVM needs to be revised to address the recent wildfire  
5 legislation, SB 762. PacifiCorp has separately sought to defer costs for activities  
6 addressed in the Company's WPP, and will seek to recover those costs through an  
7 automatic adjustment clause, in line with the language in the statute providing for  
8 recovery of all costs incurred by the utility. This modification is discussed by  
9 Ms. Steward in her testimony. Second, the WMVM, as currently configured, only  
10 allows PacifiCorp to recover all of its costs if it either spends only up to what is  
11 included in base rates or spends an enormous amount to send crews to every line  
12 every year to ensure there are less than 75 probable violations found in the audit the  
13 following year. Neither option is in the interest of customers because limiting  
14 spending does not promote reliability and spending the amounts required to trim  
15 every line-mile every year increases rates unnecessarily. Accordingly, PacifiCorp  
16 proposes changes to incentivize incremental spending to promote a robust vegetation  
17 management program and provide for recovery of larger increases in spending if they  
18 provide significant reductions in violations.

19 **Q. Is PacifiCorp proposing other revisions to the WMVM, beyond the structural**  
20 **changes discussed above?**

21 A. Yes, PacifiCorp is proposing four changes to improve the efficiency and functioning  
22 of this mechanism:

23 1) Modification of the violation criteria for the level of violations.

- 1           2) Modification of the Safety Staff audit to verifiable violations on lines
- 2           trimmed within two years.
- 3           3) Modification of the basis point penalty to a sharing percentage.
- 4           4) Full recovery of costs due to inflation and new regulatory mandates.

5 **Q. Why is PacifiCorp proposing to modify the violation criteria for the level of the**  
6 **violations?**

7 A. In reviewing the violation levels that Staff has proposed for Portland General Electric  
8 Company (PGE), PacifiCorp noted that Staff has proposed violation levels that are set  
9 at exactly twice the number of violations for each violation level when compared to  
10 those that were set for PacifiCorp. For example, while violation level one is 75  
11 violations for PacifiCorp, Staff proposed to set that level at 150 violations for PGE.<sup>6</sup>  
12 While PacifiCorp and PGE are two different utilities with very different service  
13 territories, the level of violations for PGE is not so dramatically different from  
14 PacifiCorp as to justify twice the number of violations per violation level. Therefore,  
15 PacifiCorp proposes that the number of violations corresponding to each violation  
16 level be doubled consistent with Staff's proposal for PGE.

17 **Q. What are the modifications that PacifiCorp is proposing to Safety Staff's audit?**

18 A. PacifiCorp is proposing two modifications to Safety Staff's audit. First, the current  
19 mechanism's violation levels are based on probable violations, and this is  
20 inappropriate. Any violation that is used to prevent recovery of reasonable and  
21 prudent vegetation management costs should be verified. Second, audit results from  
22 lines that are not trimmed within the cycle covered by the vegetation management

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<sup>6</sup> *In the Matter of the Application of Portland General Electric for a General Rate Revision*, Docket No. UE 394, Staff/600, Dlouhy/28 (Oct. 25, 2021).

1 mechanism should not be included as violations. Any audit of the program, as a  
2 whole, can only be valid once the utility goes through a full cycle for all rights-of-  
3 way. Otherwise, audit results from outside recently worked lines result in a penalty to  
4 the utility unless it spends the money to trim every line every year. This is  
5 additionally consistent with how Safety Staff limits its audit of overhead facilities to  
6 only those facilities that were inspected allowing for the two-year correction time  
7 period to have occurred before the audit.

8 **Q. Please explain PacifiCorp's proposal to modify the basis point penalty**  
9 **percentage.**

10 A. PacifiCorp is proposing to modify basis point penalty percentage to a sharing  
11 percentage penalty. Instead of imposing an earnings test on recovery, it is more  
12 appropriate to create a sharing mechanism, whereby a greater level of violations  
13 results in otherwise prudent expenditures partially shifting to shareholders if  
14 violations do not meet the criteria.

15 **Q. Please explain PacifiCorp's proposal to allow for full recovery of costs related to**  
16 **inflation and regulatory mandates.**

17 A. Costs related to inflation and new regulatory mandates are entirely outside of  
18 PacifiCorp's control. Therefore, it is not appropriate that the Company be denied  
19 recovery of these costs. A utility should be encouraged to adopt new programs in  
20 response to regulatory requirements as soon as possible. Additionally, the recent  
21 increase in costs due to inflation and labor costs, along with general competition  
22 across the industry for skilled vegetation management companies, puts a substantial  
23 amount of risk on the utility. As a result, PacifiCorp proposes that the recovery of



1 those costs occur on a dollar-for-dollar level outside of the performance-based  
 2 limitations that are described above. PacifiCorp proposes to calculate the annual  
 3 inflation based on IHS Markit indices. These costs would then be included in the  
 4 Company's annual filing as a separate line item for full recovery, subject to review by  
 5 parties.

6 **Q. How would PacifiCorp's proposal compare to the current WMVM?**

7 A. Table 3, below, compares the current program and the program proposed by  
 8 PacifiCorp.

9 **Table 3: Comparison of the Current WMVM to PacifiCorp's Proposed Mechanism**

CURRENT MECHANISM				PROPOSED MECHANISM				
\$30m	Base Rates			\$50m	Base Rates	Increase to transition to a 3-year cycle program and address inflationary cost pressures		
\$30m - \$36.645m	Recovery based on earnings test	<b>Number of Violations</b>	<b>Earnings Test</b>	\$50m - \$58m	Recovery based on sharing bands	<b>Number of Violations</b>	<b>Sharing Bands</b>	
		0 - 74	NONE			0-150	NONE	- Actual Violations - Line inspected in cycle
		75 - 149	- 100 BP			151-300	95/5	
		150 - 199	- 150 BP			300-500	90/10	
200+	- 200 BP	>500	80/20					
>\$36.645m	Recovery based on earnings test	<b>Number of Violations</b>	<b>Earnings Test</b>	>\$58m	Recovery based on sharing bands	<b>Number of Violations</b>	<b>Sharing Bands</b>	
		0 - 149	NONE			0-74	NONE	- Actual Violations - Line inspected in cycle
		150+	- 50 BP			>74	50/50	
Violations	System Audit (includes lines not inspected in current cycle)			Violations	Lines in cycle audit (lines inspected within the term of the mechanism)			
	All Probable Violations				Actual Violations			
				Exceptions	Inflation Adjustment			
					Changes in Regulatory Requirements after setting base rates			
				Outside of Mechanism	\$15.8m (WPP)	Subject to balancing account treatment per SB 762		

**VII. CONCLUSION**

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**Q. Please summarize your recommendation to the Commission.**

A. My testimony demonstrates that there can be significant costs and impacts to the Company and its customers associated with wildfires. Therefore, it is prudent for PacifiCorp to make incremental investments in wildfire mitigation projects to reduce the risk of wildfires caused by its facilities in its service territories, especially as wildfires have grown in frequency and severity in the West. Additionally, my testimony details the increases in costs for vegetation management, and changes to the WMVM to improve its effectiveness and functionality. I recommend the Commission approve these investments and proposed changes.

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

A. Yes.

Docket No. UE 399  
Exhibit PAC/701  
Witness: Allen Berreth

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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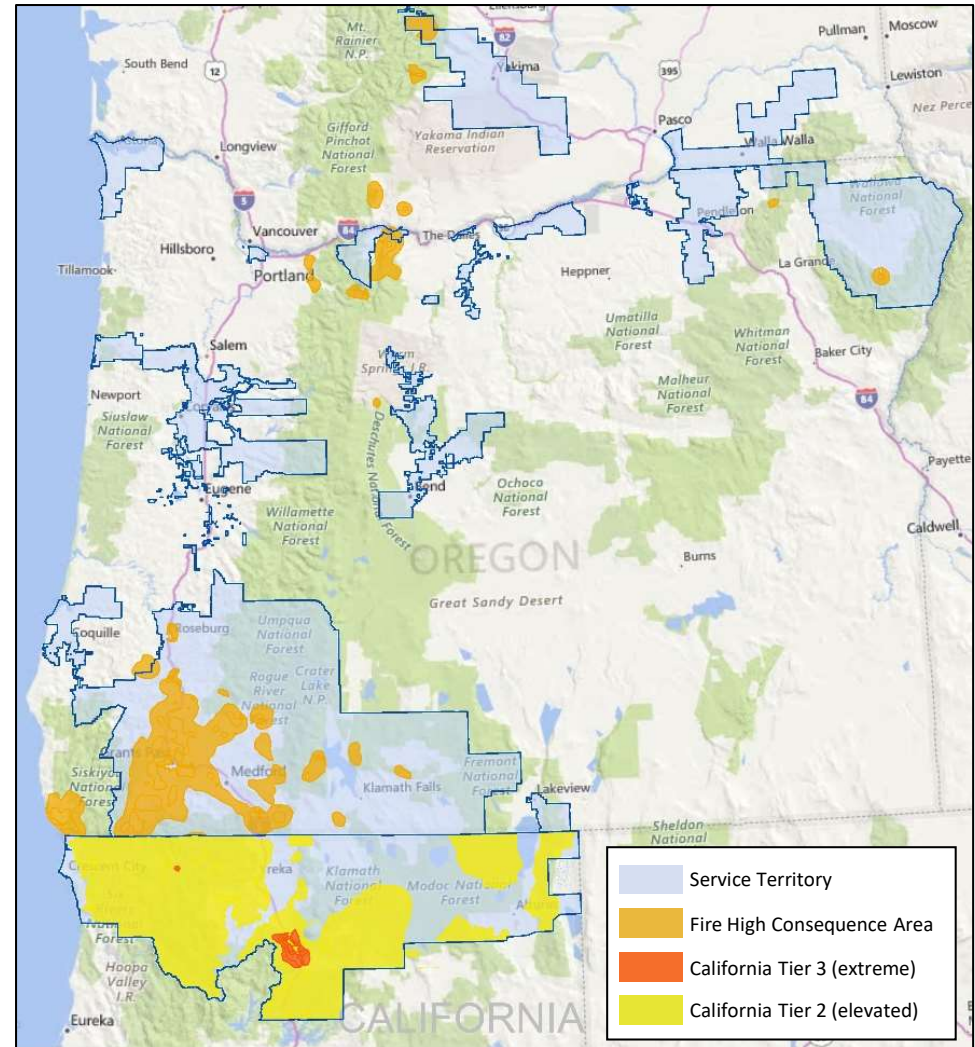
**Exhibit Accompanying Direct Testimony of Allen Berreth  
PacifiCorp Service Territory with FHCA**

**March 2022**

## RISK-BASED APPROACH: Fire High Consequence Areas (FHCA)

- Utilizing the same modeling concepts used in California, areas were identified in Oregon and Washington where there is an elevated risk of utility-associated wildfires to **occur** and **spread rapidly**, and where communities face an elevated risk of damage or harm from wildfires
- Per state requirement in California, Tier 3 and Tier 2 are shown regardless if facilities exist in the area; making the impact of Tier 2 seem larger than it is
- In Oregon and Washington, a similar methodology was used to identify FHCAs
- FHCAs are used to prioritize wildfire mitigation initiatives, such as, increased inspections, system hardening and proactive de-energization

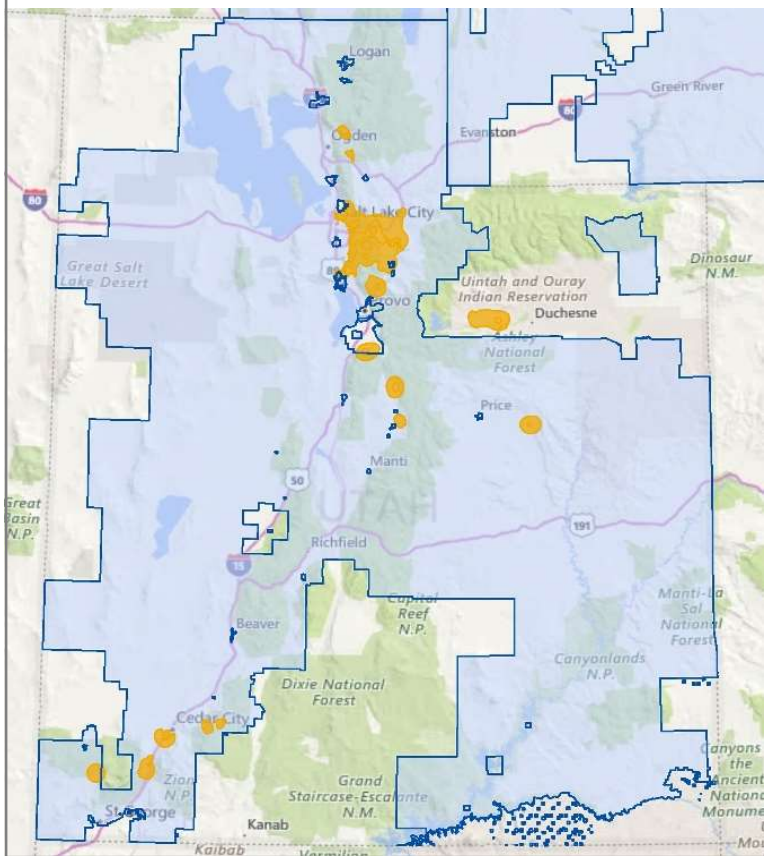
Washington, Oregon, California Service Territory



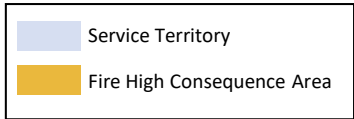
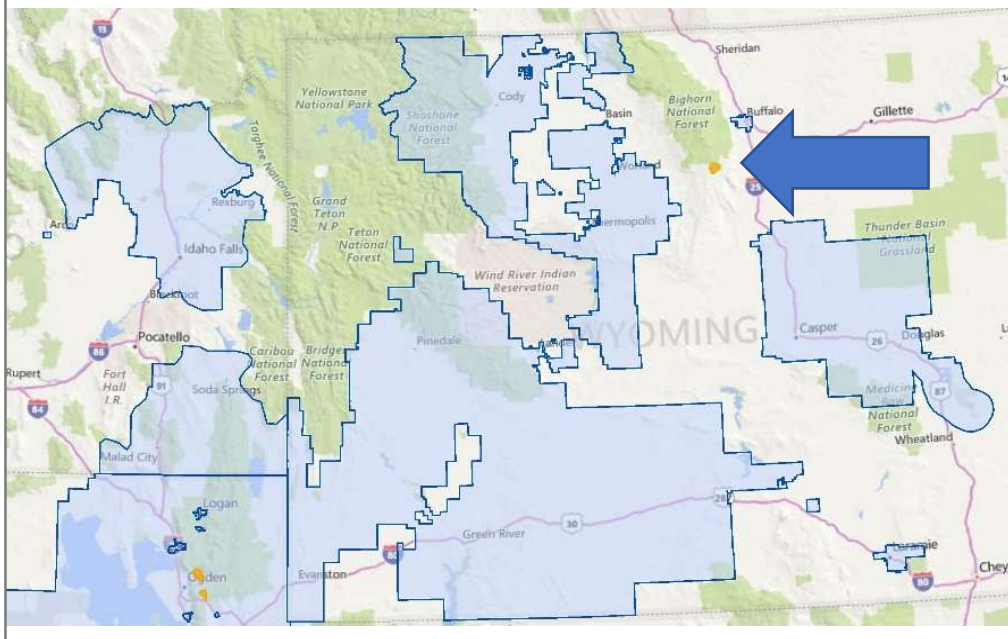


# RISK-BASED APPROACH: Fire High Consequence Areas (FHCA)

## Utah Service Territory



## Wyoming / Idaho Service Territory



Docket No. UE 399  
Exhibit PAC/800  
Witness: Erik Anderson

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Direct Testimony of Erik Anderson**

**March 2022**

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## ATTACHED EXHIBITS

Exhibit PAC/801—Proposed Schedule 273 Nonresidential Accelerated Commitment Tariff

1                                   **I. INTRODUCTION AND QUALIFICATIONS**

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

4   A. My name is Erik Anderson, and my business address is 825 NE Multnomah Street,  
5   Suite 2000, Portland, Oregon 97232. I am currently employed as the Strategic  
6   Manager of Renewable Energy and Emerging Technology with PacifiCorp.

7   **Q. Please describe your education and professional experience.**

8   A. I received a Bachelor of Science degree in Liberal Studies from Portland State  
9   University in 2005, and a Juris Doctorate degree from the Northwestern School of  
10   Law at Lewis and Clark College in 2010. My current position focuses on policies and  
11   programs that facilitate the development of customer sited energy resources as well as  
12   the development of voluntary renewable programs. Prior to my current position I was  
13   the Customer Generation Manager at PacifiCorp.

14                                   **II. PURPOSE OF TESTIMONY**

15   **Q. What is the purpose of your direct testimony?**

16   A. The purpose of my testimony is to describe PacifiCorp's proposed voluntary  
17   renewable energy tariff (VRET) for nonresidential customers, which is proposed in  
18   Schedule 273, Accelerated Commitment Tariff (ACT). I have included proposed  
19   Schedule 273 as Exhibit PAC/801. I also explain how the program satisfies the



1 design conditions approved in Public Utility Commission of Oregon (Commission)  
2 Order 16-251<sup>1</sup> and subsequently modified by Order 21-091.<sup>2</sup>

3 **Q. Please summarize your recommendation in this proceeding.**

4 A. I recommend that the Commission approve PacifiCorp's proposed Schedule 273.

5 **Q. Is approval of specific customer agreements part of the Company's proposal in**  
6 **this proceeding?**

7 A. No. Currently, PacifiCorp is not seeking approval of a specific customer agreement,  
8 resource selection or credit value. Instead, PacifiCorp will seek approval of those  
9 items through compliance filings as customer specific agreements are finalized.

10 **III. OVERVIEW OF THE ACT**

11 **Q. Please summarize PacifiCorp's ACT.**

12 A. As explained by Ms. Joelle R. Steward, the ACT program will provide customers the  
13 opportunity to accelerate the decarbonization of their energy supply by facilitating the  
14 development of new renewable energy facilities. Through specified renewable  
15 resources that are incremental additions to those selected for system use, PacifiCorp  
16 will provide bundled renewable energy and the corresponding renewable energy  
17 certificates (RECs) sufficient to meet the customers' goals. PacifiCorp will leverage  
18 existing competitive procurement processes to identify potential projects eligible for  
19 ACT. This will allow the Company to identify a variety of resources that meet

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<sup>1</sup> *In the Matter of Public Utility Commission of Oregon, Voluntary Renewable Energy Tariff for Nonresidential Customers*, Docket No. UM 1690, Order No. 16-251 (Jul. 5, 2016).

<sup>2</sup> *In the Matter of Portland General Electric Company, Investigation into Proposed Green Tariff*, Docket No. UM 1953, Order No. 21-091 (Mar. 29, 2021); Order No. 21-096 (Mar. 30, 2021), correcting Order No. 21-091.

1 customer expectations while minimizing costs and maximizing overall system  
2 benefits.

3 **Q. Is the proposed ACT designed to avoid cost-shifting between participants and**  
4 **non-participants?**

5 A. Yes. The ACT has a few key components which are designed to avoid cost shifting  
6 from participants to non-participants.

7 First, ACT participants will remain on their current rate schedule and any  
8 applicable riders or supplemental schedules. The cost of participation in the program  
9 will be captured through a supplemental rider that reflects all costs for the program.  
10 By remaining on the applicable cost-of-service rates, the participant will continue to  
11 contribute to recovery of all system costs.

12 Second, the ACT participant will pay for all administrative costs of the  
13 program and the cost of the selected renewable resources. Administrative costs for  
14 operating the program will be tracked and charged to the program. The ACT  
15 participant will also be responsible for the costs of the bundled renewable energy  
16 minus a credit that reflects the system value of the energy and the capacity from the  
17 incremental facility.

18 As explained further below, PacifiCorp will use its integrated resource plan  
19 (IRP) portfolio-based valuation method to determine the value of the incremental  
20 renewable resource to the system. This value would then be provided to the  
21 participant as a credit against the cost for the renewable resource under the contract  
22 between PacifiCorp and the participating customer.

1 **Q. How does PacifiCorp's ACT differ from its Blue Sky Program?**

2 A. PacifiCorp's Blue Sky Program merely provides for the sale of RECs to customers  
3 for retirement on their behalf, while the ACT program provides bundled energy and  
4 RECs to a participating customer. As discussed by Ms. Steward, the ACT program is  
5 designed to encourage the incremental addition of renewable resources, increasing the  
6 supply of bundled renewable energy to the grid in advance of the state policy goals of  
7 House Bill (HB) 2021.

8 **Q. Will PacifiCorp continue its Blue Sky Program?**

9 A. Yes, but only for unbundled RECs that are not associated with incremental generation  
10 resources once the Schedule 272 cap is reached.

#### 11 **IV. STRUCTURE OF PACIFICORP'S ACT**

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

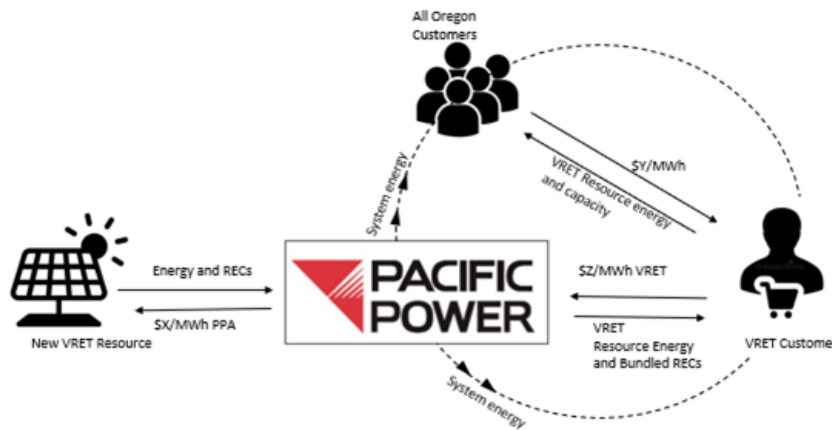
13 A. In this section of my testimony, I describe the design of the PacifiCorp's proposed  
14 ACT.

15 **Q. Please describe the structure of PacifiCorp's proposed ACT.**

16 A. Under a contract entered into between PacifiCorp and a nonresidential customer  
17 (participant), PacifiCorp will provide a participant bundled renewable electricity from  
18 one or more renewable energy resources acquired by PacifiCorp. The contract with  
19 the participant will include rates calculated to cover all costs associated with  
20 acquiring the renewable energy resource(s) and operating the program offered under  
21 ACT. To reflect the resource energy and capacity that will benefit all Oregon  
22 customers, the participant will receive a credit for the contracted megawatt-hours  
23 (MWh). The structure of ACT is depicted in Figure 1 below.

1

**Figure 1: ACT Structure**



2 **Q. What type of renewable energy resources will be eligible under the ACT?**

3 **A.** There are four criteria for a renewable energy resource to be eligible under the ACT.

4 First, a renewable resource must derive its energy from a renewable energy source as  
5 defined under Oregon Revised Statute (ORS) §469.025. A non-carbon emitting

6 energy storage resource may be included only in conjunction with Resource Portfolio

7 Standard (RPS)-compliant facilities. Second, consistent with ORS §469A.135,

8 a renewable resource must be located where it can provide bundled renewable energy

9 to the Company.<sup>3</sup> Third, the renewable resource must be a new resource in that it

10 must have not been operational earlier than one year prior to the resource being

11 included in the ACT program. Finally, a renewable resource eligible under the ACT

12 program must not already be included in the Company's rates.

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<sup>3</sup> It must be located in the United States, within the geographic boundary of the Western Electricity Coordinating Council, and delivered to PacifiCorp's system.

1 **Q. Please explain which nonresidential customers are eligible to participate in the**  
2 **ACT program.**

3 A. Nonresidential consumers served by the Company in the state of Oregon whose total  
4 aggregated electric load is at least 30 kW, based on annual peak load, may participate  
5 in the ACT program. A customer may satisfy the 30 kW threshold by aggregating  
6 multiple metered delivery points, including individual delivery points with less than  
7 30 kW of demand, under a single entity, based on annual peak load at each delivery  
8 point. Annual peak load will be based on the customer's highest demand reading  
9 during the prior 12-month period or its reasonably projected demand including  
10 planned load expansions in the subsequent 12-month period. For new customers  
11 wanting to subscribe to the ACT program, annual peak load will be based on the new  
12 customer's contract, to be reached within a ramp-up period of 36 months.

13 **Q. Why has PacifiCorp set a 30 kW threshold?**

14 A. The 30 kW threshold was selected in order to provide larger nonresidential customers  
15 a path to procure renewable energy. HB 2021 clarified that retail electricity  
16 consumers "whose electricity demand at any point of delivery is less than 30  
17 kilowatts" should be provided a portfolio of rate options and expanded that portfolio  
18 to include a Community Green Tariff. Customers larger than 30 kW were excluded  
19 from participation in that expanded portfolio. By setting the participation threshold at  
20 30 kW, the Company will provide a similar opportunity for larger nonresidential  
21 customers to meet their renewable energy goals.

1 **Q. To participate in the ACT program, does a nonresidential customer have to take**  
2 **service under another PacifiCorp retail rate schedule?**

3 A. Yes. To participate, the nonresidential customer must continue to take service under,  
4 and pay all components of, its applicable retail rate schedule and all supplemental  
5 schedules and riders as determined for each delivery point. As such, customers that  
6 subscribe under PacifiCorp's Direct Access Delivery Service are not eligible to  
7 participate in the ACT program.

8 **Q. Why are those who take service under direct access schedules ineligible to**  
9 **participate under the ACT?**

10 A. ACT is a program that provides customers access to bundled renewable energy. It is  
11 a supplemental product that is an addition to the participant's cost-of-service rates.  
12 Participants continue to pay their share of system costs through their standard rates,  
13 reducing the risk of stranded assets. Prohibiting Direct Access customers reduces the  
14 complexity related to energy delivery, billing, establishing the credit value, and  
15 concerns about stranded assets.

16 **Q. What is the length of the contract entered into between PacifiCorp and a**  
17 **participant under the ACT?**

18 A. The contract will include a minimum term of five years as agreed to between  
19 PacifiCorp and the participant. If PacifiCorp identifies a resource through a purchase  
20 power agreement (PPA) as the best option and the term of the participant contract  
21 does not match the term of PPA(s) entered into by PacifiCorp or the asset life of the  
22 facility, the participant contract will recover all the costs identified using the IRP  
23 portfolio-based methodology described below to protect non-participating customers

1 from the mismatch between participant contract and resource supply. I will refer to  
2 this cost as the “subscriber mismatch fee” in my testimony.

3 **Q. Please explain the components of the participants’ contract rate under the ACT.**

4 A. The rate that a participant will pay under a contract will reflect the following costs  
5 and credit:

- 6 1. The participant’s normal tariff rate as specified in its applicable electric  
7 service Schedule for each delivery point;
- 8 2. The cost of the MWh of bundled renewable energy generated and  
9 delivered to the participant;
- 10 3. Cost-based administrative fees that account for program costs, billing,  
11 integration, shaping, firming and other relevant program services; and
- 12 4. Costs will be offset with a credit for the contracted MWh that reflects the  
13 energy and capacity value. The credit will be determined by the Company  
14 by using the Company’s IRP portfolio-based methodology. It will also  
15 include a risk adjustment and will be determined at the time of resource  
16 procurement and be fixed over the contract period.

17 The credit described above is designed to reflect the benefit that all cost-of-  
18 service customers receive from the additional energy and capacity provided by the  
19 renewable resources. In the end, this leaves the participant paying the delta between  
20 the resource cost and the incremental value of the additional renewable resource.

21 **Q. How do you categorize the costs that would be paid by the participant under the**  
22 **ACT?**

23 A. There are three buckets of different costs that will be paid for by the participant in the

1 ACT program, which is depicted in Figure 2 below.

2 The first cost bucket is the above-market cost from the renewable resource for  
3 the bundled renewable energy. As described above, this is the delta between resource  
4 cost and the value to the system of the resource's energy and capacity, as determined  
5 by the IRP portfolio-based valuation methodology.

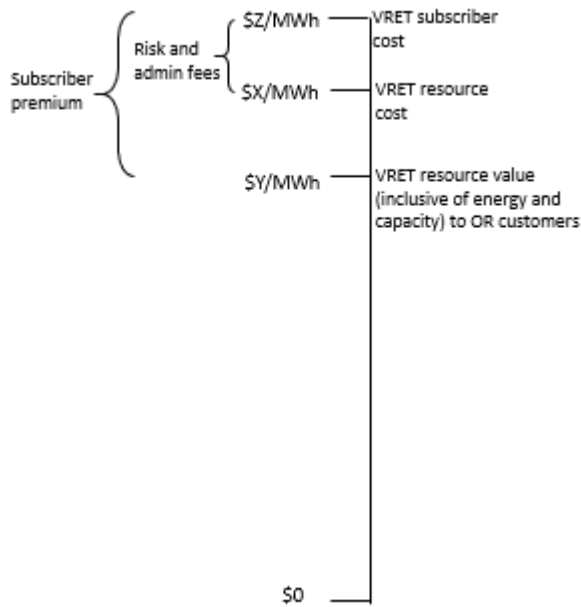
6 The second cost bucket is the subscriber mismatch fee, which is a risk  
7 premium charged to participants whose contract length differs from the length of a  
8 PPA. In short, the subscriber mismatch fee equals the net present value of the delta  
9 between the subscription duration and the PPA duration. Through this fee,  
10 PacifiCorp will protect non-participating customers from the impact of unsubscribed  
11 energy.

12 The third cost bucket is the administration fee affiliated with managing the  
13 program. All utility costs to manage the program will be tracked and charged only to  
14 participants of the program.

15 I provide additional details on these charges later in my testimony.



1 **Figure 2: Cost Categories to be paid by Participants under the ACT**



2 **Q. Who will benefit from the environmental attributes associated with participation**  
3 **in the PacifiCorp ACT?**

4 A. The primary beneficiary of the environmental attributes associated with participation  
5 in the ACT program as represented by the RECs will flow to the individual  
6 participants of the program. Consistent with the Commission’s condition 2 for the  
7 design of VRET programs, which I discuss further below, RECs affiliated with this  
8 program will either be retired by the utility on behalf of the participating customer or  
9 transferred to the customer’s Western Renewable Energy Generation Information  
10 System account to be retired by the customer directly.

11 In addition, all customers will benefit indirectly as new “additional”  
12 renewable energy facilities will be interconnected into the grid lowering the actual

1 carbon intensity of the energy supply in furtherance of the carbon reduction targets  
2 included in HB 2021. See Ms. Steward's testimony for further discussion.

3 **Q. Will the contract entered into between PacifiCorp and the subscribing customer**  
4 **include termination provisions?**

5 A. Yes. The termination provisions will include obligations of the customer to pay all of  
6 the costs of the renewable energy resource(s) procured by PacifiCorp on the  
7 customer's behalf in the event of early termination. In short, the customer will pay all  
8 costs they would have paid under the duration of the contract.

9 **Q. Will a subscribing customer have the option to transfer a contract of one**  
10 **delivery point to another without incurring termination fees?**

11 A. Yes. At the discretion of the Company, a customer with multiple delivery points shall  
12 have the option to transfer the renewable energy contract obligation of one delivery  
13 point to a new or existing delivery point within the Company's Oregon service  
14 territory without termination fees.

15 **V. ENERGY AND CAPACITY CREDITS**

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

17 A. In this section of my testimony, I discuss the energy and capacity credits that will be  
18 part of the contract rate for nonresidential customers participating in the ACT  
19 program.

1 **Q. You stated that a participating customer's contract rate will include a credit**  
2 **from non-participating customers based on the energy and capacity additions**  
3 **made to PacifiCorp's system. Please provide additional detail regarding that**  
4 **proposed mechanism.**

5 A. The credit represents the system benefit of the additional resource being brought to  
6 the system. The credit is inclusive of energy and capacity value of the specific  
7 resource using the same methodology used to develop PacifiCorp's IRP and in long-  
8 term resource evaluation conducted during a request for proposals for resources. The  
9 IRP portfolio-based resource valuation methodology compares the system costs of  
10 different portfolios of resources that could be used to serve customers, and accounts  
11 for all of the costs associated with utility-scale resources, along with the specific  
12 benefits a portfolio of resources provides. As a benefit being brought to the system  
13 by the customer, the credit is used to offset the contracted cost of the resource.

14 The Company's IRP portfolio-based modeling does not pre-suppose the  
15 values for these benefits applicable to a particular resource.

16 **Q. How is the energy and capacity credit calculated?**

17 A. The energy and capacity credit is calculated by determining the system benefit of the  
18 additional resource. The system benefit is based on two simulations in the IRP  
19 model, one for a portfolio that includes the incremental generation from the project  
20 and one for a portfolio that does not include the incremental generation from the  
21 project. As a result, the credit will reflect the difference in total system cost for a  
22 portfolio with the additional resource, relative to the least-cost, least-risk portfolio  
23 that does not include that resource. The system value of the incremental energy is

1 converted to a dollar-per MWh value by dividing the reduction in annual system costs  
2 by the participant's subscribed volume.

3 **Q. Would the energy and capacity credit change during a customer's course of**  
4 **participation?**

5 A. No. The credit and volume are fixed at the time of PPA signing or resource  
6 investment decision for PacifiCorp-owned resources. This supports transparency for  
7 participants regarding costs of participation.

8 **Q. Is PacifiCorp requesting that the Commission approve the values associated with**  
9 **the credits at this time?**

10 A. No. PacifiCorp is only requesting approval of the tariff structure. Included in that  
11 tariff structure are the methods through which PacifiCorp will determine the customer  
12 pricing and the credit value the customer receives. The specific values will be  
13 brought to the Commission as a compliance filing upon execution of a customer  
14 agreement. At that time, PacifiCorp will seek approval of the specific values.

15 **VI. SUBSCRIBER MISMATCH FEE AND ADMINISTRATION FEE**

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

17 A. In this section of my testimony, I discuss the subscriber mismatch fee and  
18 administrative fee for which participants will be responsible under the contract  
19 entered into under the ACT.

20 **Q. What is the subscriber mismatch fee?**

21 A. As I described above, for participants that subscribe to the program in terms that are  
22 not equivalent to the length of a PPA, the net present value of the above market costs  
23 for the full duration of the contract are spread across the years to which the

1 participants have subscribed. This is the only risk captured in the subscriber  
2 mismatch fee.

3 **Q. Why is the subscriber mismatch fee necessary?**

4 A. One of the primary goals of the program is to limit the risk of cost increases for non-  
5 participants. Through the subscriber mismatch fee, the risk of unsubscribed energy at  
6 the end of a participant contract raising costs for non-participants are reduced. As the  
7 subscriber is paying all costs of the additional resource over the term of their contract,  
8 there are no remaining above-market costs for cost-of-service customers to bear.

9 **Q. Will the subscriber mismatch fee apply to PacifiCorp-owned resources?**

10 A. Yes, if a Company-owned resource is selected a subscriber mismatch fee would  
11 apply. The methodology for calculating the costs and benefits would be  
12 fundamentally the same. The primary difference would be the term for which the  
13 costs and benefits were evaluated. With a PPA the term would be the duration of the  
14 PPA, while for a Company-owned resource the term would be the asset life of the  
15 facility.

16 **Q. How will PacifiCorp limit the risk of unsubscribed energy to non-participants in  
17 this program?**

18 A. PacifiCorp will limit the risk of unsubscribed energy by working to match participant  
19 demand with the size of the contracted resource. PacifiCorp will wait to enter into a  
20 PPA or invest in a resource until the resource is adequately subscribed. PacifiCorp  
21 will also manage a participation queue for interested customers seeking to participate  
22 in the next resource. Should a participant unexpectedly drop out of the program, that  
23 capacity will be offered to customers in order of queue position.

1 **Q. Please explain the administration fee.**

2 A. PacifiCorp will assign all costs to administer the program to the participants in the  
3 ACT program. An administrative adder is built into the ACT tariff design to cover  
4 program operation costs that are applicable only to participants. This fee is structured  
5 as a per-MWh adder to the subscription costs, and initially is based on estimate of  
6 costs in similar programs like the Blue Sky programs. These costs are not inclusive  
7 of program design and startup costs that are available to all customers (e.g., website  
8 and issuance of request for proposal (RFP) but include ongoing costs for operation of  
9 the program (including staff oversight time and REC retirement)). Upon approval of  
10 the program all costs will be assigned to be collected from program participants.

11 **VII. PLANNING AND COMPLIANCE IMPACTS**

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

13 A. In this section of my testimony, I discuss the impacts of the renewable energy  
14 resources contracted for under the ACT on the PacifiCorp's RPS obligations and IRP  
15 planning.

16 **Q. Will the ACT resources contribute toward PacifiCorp's RPS obligations?**

17 A. No, the renewable attributes of ACT affiliated facilities, as represented by the RECs  
18 from the facility, will not be used to satisfy PacifiCorp's RPS compliance  
19 requirements. As described above, RECs will be retired on behalf of the participant  
20 or transferred to the participant for retirement.

21 **Q. How will PacifiCorp incorporate the ACT resources in its IRPs?**

22 A. ACT resources will be incorporated into the IRP when the contracts are executed.

1 **Q. How will PacifiCorp address the ACT resource generation in its calculation of**  
2 **net power costs?**

3 A. Resource costs and benefits, including the participant buy-down, are situs-assigned to  
4 Oregon consistent with the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol.<sup>4</sup>  
5 Other states will see the ACT resource reflected in their net power costs as a market  
6 purchase.

7 **VIII. CUSTOMER INTEREST**

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

9 A. In this section of my testimony, I will explain the process that PacifiCorp will  
10 undertake to determine customer interest in participating in the ACT program.

11 **Q. How will PacifiCorp determine customer interest for participation?**

12 A. Since 2016 when HB 4126 raised the possibility of utility offered voluntary  
13 renewable energy programs, PacifiCorp has held informal discussions with customers  
14 that have expressed interest in a utility program. To this point PacifiCorp has not  
15 asked for a formal declaration of interest from any customers and the Company has  
16 simply gauged interest and relative size of the associated loads. As the approval  
17 process for the ACT begins to take shape, PacifiCorp will ask interested customers to  
18 submit a non-binding “Expression of Interest” commitment form. This “Expression  
19 of Interest” will allow the Company to develop an estimate of resource size needed to  
20 satisfy the existing customer interest in the program.

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<sup>4</sup> *In the matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, Order No. 20-024 (Jan. 23, 2020).

1 **Q. What levels of participation will be required for PacifiCorp to implement the**  
2 **program?**

3 A. PacifiCorp has not preestablished a floor that must be met to initiate the program.  
4 Instead, through the “Expression of Interest” process described above, PacifiCorp will  
5 be able to determine the size of a needed resource, or resources, and the associated  
6 participant tolerance for additional costs.

7 **IX. RESOURCE SELECTION**

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

9 A. In this section of my testimony, I discuss how PacifiCorp will select resources  
10 eligible for the ACT program.

11 **Q. How will PacifiCorp secure resources for the PacifiCorp ACT Program?**

12 A. Initially, PacifiCorp plans to leverage its existing procurement process initiated as a  
13 result of the 2021 IRP<sup>5</sup>, the 2022 All-Source RFP (2022AS RFP).<sup>6</sup> The IRP action  
14 plan and the subsequent RFPs will identify least-cost, least-risk resources for the  
15 system prioritizing selection for all cost-of-service customers. Next, PacifiCorp will  
16 identify additional least-cost resources for compliance with other state policy  
17 obligations on behalf of the state’s retail customers, including Oregon’s Renewable  
18 Portfolio Standard and HB 2021. Projects that are not selected for system or state-  
19 specific needs will be considered as potential projects for the ACT program.

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<sup>5</sup> *In the Matter of PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan*, Docket No. LC 77. See also, <https://www.pacificcorp.com/energy/integrated-resource-plan.html>.

<sup>6</sup> *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of 2022 All-Source Request for Proposals*, Docket No. UM 2193.



1 **Q. Will PacifiCorp ACT participants get preference over PacifiCorp resource**  
2 **procurement for its system load?**

3 A. No, first preference for resources identified in the 2022AS RFP will go to satisfy  
4 system resource needs identified through the 2021 IRP along with state policy  
5 obligations on behalf of all retail customers, as described above. Only bids that are  
6 not otherwise cost-effective for system or state obligations will be available to satisfy  
7 the demand of the ACT program.

8 **Q. Is PacifiCorp planning to own any of the ACT resources?**

9 A. PacifiCorp will consider both PPAs and company-owned assets as eligible renewable  
10 resources for the ACT program. For the initial implementation, as I discussed earlier,  
11 PacifiCorp will leverage its ongoing 2022AS RFP, where the energy can be secured  
12 through a PPA, unless a more economic owned-resource opportunity were to develop.  
13 As such, the Company is not proposing any specific accounting safeguards to track  
14 return on investment at this time. With regard to other expenses, after the tariff is  
15 approved, all costs for marketing, offering and operation of the act program will be  
16 separately accounted for and allocated directly to participants through the  
17 administration fee. Prior to investing in any owned resources for the ACT program,  
18 PacifiCorp will bring a proposal of specific safeguards before the commission for  
19 consideration.

20 **X. COMPLIANCE WITH THE COMMISSION'S VRET CONDITIONS**

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

22 A. In Order 16-251, the Commission established nine conditions that a VRET design  
23 must meet. The Commission subsequently modified the VRET design criteria to

1 eight conditions in its review of Portland General Electric's VRET in Order 21-091.<sup>7</sup>

2 In this section of my testimony, I explain how PacifiCorp's ACT meets these  
3 conditions.

4 **Q. Please list the eight VRET conditions identified by the Commission.**

5 A. The eight conditions are as follows:

6 **Condition 1.** RPS definitions that must apply to voluntary renewable energy  
7 products are for resource type, location, and bundled RECs. Non-carbon emitting  
8 energy storage resources may be included but only in conjunction with RPS-  
9 compliant resources.

10 **Condition 2.** Voluntary renewable energy options include only bundled REC  
11 products. Any RECs associated with serving participants must be retired by or on  
12 behalf of participants.

13 **Condition 3.** The year that a VRET-eligible resource becomes operational shall be  
14 no earlier than one year prior to the resource being included in the program.

15 **Condition 4.** The VRET program size is limited to 300 average megawatts (aMW)  
16 for PGE and 175 aMW for PacifiCorp.

17 **Condition 5/6.** VRET offerings, as customer choice products, can impact the  
18 competitive retail market for some customer segments even when differentiated from  
19 direct access offerings. The utility bears the burden of proof to demonstrate that a  
20 VRET offering does not unfairly undermine Direct Access Programs.

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<sup>7</sup> In Order No. 21-091, the Commission consolidates the original Condition 5 and Condition 6 into one Condition 5/6.

1           **Condition 7.** The regulated utility may own a voluntary renewable energy resource,  
2           but may not include any voluntary renewable energy resource in its general rate base.  
3           It may recover a return on and return of its investment in the voluntary renewable  
4           energy resource from the subscriber; however, the utility must share some of the  
5           return on investment with the other utility customers for ratepayer-funded assets used  
6           to assist the voluntary renewable offering.

7           **Condition 8.** All direct and indirect costs and risks are borne by the participating  
8           voluntary renewable energy tariff customers, shareholders of the utility or third-party  
9           developers and suppliers with provisions allowing independent review and  
10          verification by Commission Staff of all utility costs. Costs include but are not limited  
11          to ancillary services and stranded costs of the existing and additional future cost-of-  
12          service rate-based system.

13          **Condition 9.** All voluntary renewable offerings must be made publicly available and  
14          subject to review by the Commission to ensure they are fair, just, and reasonable.

15   **Q.    Has PacifiCorp designed the ACT to meet the requirements included within the**  
16   **eight conditions?**

17   **A.    Yes.**

1 **Q. Please explain how the PacifiCorp ACT meets Condition 1.**

2 A. PacifiCorp has not selected the resources that will be used for the program at this  
3 time. Resources that are selected will conform with the definitions for resource type,<sup>8</sup>  
4 location,<sup>9</sup> and bundled RECs<sup>10</sup> currently included in Oregon Law.

5 **Q. Please explain how the PacifiCorp ACT meets Condition 2.**

6 A. PacifiCorp's program is designed to encourage the development of new renewable  
7 resources and provide a bundled renewable energy certificate to the customer. The  
8 contracts affiliated with this program will cover the energy, capacity and renewable  
9 attributes of the facilities. PacifiCorp will ensure that the RECs associated with this  
10 program are retired on behalf of the participant.

11 **Q. Please explain how the PacifiCorp ACT meets Condition 3.**

12 A. PacifiCorp will only select new incremental renewable resources. Thus, no projects  
13 that are operational for more than one year prior to inclusion in the program will be  
14 selected as designated resources.

15 **Q. Please explain how the PacifiCorp ACT meets Condition 4.**

16 A. PacifiCorp believes that 175 aMW is sufficient to meet the demand from existing  
17 customers for a voluntary renewable energy program. Should demand from existing  
18 customers exceed 175 aMW the Company will prospectively seek approval from the  
19 Commission to expand the program, in a manner that is procedurally consistent with  
20 guidance provided by the Commission in Order 21-091.<sup>11</sup>

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<sup>8</sup> ORS 469A.025.

<sup>9</sup> ORS 469A.135.

<sup>10</sup> ORS 469A.005.

<sup>11</sup> Order No. 21-091 at 16.

1 **Q. Please explain how the PacifiCorp ACT meets Condition 5/6.**

2 A. As designed, the ACT program is a premium offering where participants remain on  
3 cost-of-service rates and agree to pay a premium to participate in this program.  
4 While the premium alone does not prove that this program will not undermine Direct  
5 Access programs, there are additional program features that are not placed on Direct  
6 Access providers that will impact participant interest. First, the constraints included  
7 within Condition 1 and Condition 3 on the resource type, location and vintage of  
8 projects will limit the options for customers interested in the ACT program. Second,  
9 the available contract terms, a minimum of five years, in combination with the  
10 subscription mismatch fee, ensure that participants are paying all costs for the  
11 additional resources for the full duration of the contract. This extended financial  
12 commitment is not required from Direct Access customers. Third, the program  
13 feature that requires customers to remain on cost-of-service rates and exposed to  
14 future rate changes eliminates the ability to use this program as a hedge for their  
15 electricity supply costs. In total the premium nature of the ACT program combined  
16 with the restrictive procurement, commitment length and lack of any hedge value  
17 suggest that the ACT program will not undermine the Direct Access programs.

18 **Q. Please explain how the PacifiCorp ACT meets Condition 7.**

19 A. PacifiCorp will consider both PPAs and company-owned assets as eligible renewable  
20 resources for the ACT program. In the initial implementation, PacifiCorp will  
21 leverage its ongoing 2022AS RFP, where the energy can be secured through a PPA,  
22 unless a more economic owned-resource opportunity were available. The Company  
23 will not seek to recover a return on investment for PPA projects. Prior to considering

1 Company-owned resources for participation in the ACT program, PacifiCorp will  
2 identify the specific accounting for the resource in a filing with the Commission,  
3 including either a mechanism to share any return on investment associated with  
4 owned resources in the ACT program with other customers or why the accounting  
5 protections are sufficient so that other customers are not harmed and sharing would  
6 not be appropriate. PacifiCorp will not include any Company-owned renewable  
7 resources affiliated with the ACT program in its general rate base. Costs will instead  
8 be recovered from participants in the ACT program.

9 **Q. Please explain how the PacifiCorp ACT meets Condition 8.**

10 A. The ACT program assigns all ancillary program costs to participating customers, this  
11 includes administration and other ancillary services. Additionally, requiring  
12 customers to remain on the applicable cost of service rates for delivery points  
13 participating in the program means that participating customers continue to pay for  
14 their share of all system costs.

15 **Q. Please explain how the PacifiCorp ACT meets Condition 9.**

16 A. All agreements affiliated with this program will be available to Staff for review. Staff  
17 will be able to verify all terms, conditions and prices affiliated with these agreements.  
18 PacifiCorp will make these agreements available on a confidential basis to protect  
19 customer-specific and project-specific information.

20 **XI. CONCLUSION**

21 **Q. Please summarize your recommendation to the Commission.**

22 A. I recommend that the Commission approve PacifiCorp's proposed ACT.

1 Q. **Does this conclude your direct testimony?**

2 A. Yes.

Docket No. UE 399  
Exhibit PAC/801  
Witness: Erik Anderson

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Erik Anderson  
Proposed Schedule 273 Nonresidential Accelerated Commitment Tariff**

**March 2022**



**Purpose**

This Schedule governs contract guidelines for the Company to acquire renewable energy from new renewable resources on behalf of participating Customers. Under this Schedule, a Nonresidential Consumer may commit to the purchase of bundled renewable energy from a new renewable facility, or group of facilities, in a quantity not to exceed the Customer's yearly consumption.

**Available**

In all territory served by the Company in the State of Oregon.

**Applicable**

To Nonresidential Consumers served by the Company in the state of Oregon whose total aggregated electric load is at least 30 kW, based on annual peak load. A Customer may aggregate multiple metered delivery points, including individual delivery points with less than 30 kW of demand, under a single entity to satisfy the 30 kW threshold, based on annual peak load at each delivery point. Annual peak load will be based on the Customer's highest demand reading during the prior 12-month period or its reasonably projected demand including planned load expansions in the subsequent 12-month period. For new Customers, annual peak load will be based on the Customer's Contract Demand, to be reached within a ramp-up period of 36 months or such other period approved by the Commission.

**Conditions of Service**

- 1) A contract is required for each Customer taking service under this Schedule. The Customer contract is subject to approval by the Commission.
- 2) While a participant in this Schedule, each Customer shall continue to take service under, and pay all components of, their applicable rate schedule and all supplemental schedules and riders as determined for each delivery point. Customers who subscribe to Direct Access Service, are ineligible for this program.
- 3) The Customer contract will provide for delivery of bundled renewable electricity to the Customer by the Company from one or more renewable energy resources. See Conditions of Service paragraph 6, below, for eligible renewable energy resources criteria.

(continued)

(N)

(N)

NONRESIDENTIAL ACCELERATED COMMITMENT TARIFF (ACT)

**Conditions of Service (continued)**

(N)

- 4) The Customer contract will include:
- a) The amount of renewable energy to be acquired on behalf of the Customer annually. This amount shall not exceed the reasonably projected annual amount of energy to be consumed by the Customer. In the event of yearly under generation from the renewable energy resource(s) facilitated through the contract, the Company will purchase renewable energy certificates (RECs) on the Customer's behalf to ensure the Customer's subscribed quantity of energy is covered.
  - b) The Customer contract will include rates calculated to cover all costs associated with acquiring the renewable energy resource(s) and operating this supplemental program. Under the Customer contract the Customer shall pay:
    - i) The Customer's normal tariff rate as specified in the applicable Electric Service Schedule for each delivery point:
    - ii) The cost for the contracted megawatt-hours (MWh) of bundled renewable energy generated and delivered to the customer:
    - iii) Cost-based administrative fees that account for program costs, billing, and other relevant program expenses:
    - iv) The credit for the contracted MWh that reflects the energy and capacity value, as well as integration, shaping, and firming costs. The bill credit amount is determined by the Company, using the Company's integrated resource plan (IRP) portfolio-based valuation methodology. The credit value will include a risk adjustment, will be determined at the time of resource procurement, and will be fixed over the contract period.
    - v) The subscriber mismatch charge that ensures that incremental renewable energy resource costs are recovered during the term of the Customer's agreement.
  - c) The Customer contract will include a term no less than five years, as agreed to between the Company and the Customer. Should the term of the contract differ from the term of the renewable energy resource(s), the subscriber mismatch charge identified in the contract will recover all of the costs identified using the IRP portfolio-based valuation methodology to protect non-participating cost of service Customers from the mismatch between contract durations.
  - d) The Customer contract will contain service termination provisions obligating the Customer to pay all of the costs of the renewable energy resource(s) procured by the Company on the Customer's behalf in the event the Customer contract is terminated early, and a cost obligation related to the renewable energy resource(s) continues beyond the termination. At the discretion of the Company, a Customer with multiple delivery points shall have the option to transfer the renewable energy resource obligation of one delivery point to a new or existing delivery point within the Company's Oregon service territory without termination fees.
  - e) The Customer shall be required to provide adequate credit assurances.

(continued)

(N)

**Conditions of Service (continued)**

(N)

- 5) At the request of a Customer, the Company may agree to enter into a new contract with another Customer to accommodate a transfer of the Customer's rights and obligations with respect to a renewable energy resource to another Customer, subject to Commission approval of the new contract.
- 6) The following provisions set out the criteria for renewable energy resources eligible under this Schedule:
  - a) A renewable resource must derive its energy from a renewable energy source as defined in Oregon Revised Statute 469A.025. Non-carbon emitting energy storage resources may be included, but only in conjunction with Renewable Portfolio Standards-compliant resources.
  - b) A renewable resource must be located where it can provide bundled renewable energy to the Company, as such it must be located in the United States and within the geographic boundary of the Western Electricity Coordinating Council consistent with Oregon Revised Statute 469A.135. The Company will take physical delivery of output from the renewable resource and will provide electric service to the Customer.
  - c) A renewable resource must be new, meaning that the facility must not have been operational earlier than one year prior to the resource being included in the program.
  - d) A renewable resource eligible for contract under this Schedule must not already be included in the Company's rates.
  - e) The renewable resource procurement will be negotiated by the Company and all terms and conditions are subject to the Company's agreement.
- 7) RECs associated with renewable energy delivered under this Schedule will be deposited into an account maintained by or on behalf of the Customer and will be retired.

(N)

Docket No. UE 399  
Exhibit PAC/900  
Witness: Kenneth L. Elder, Jr

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Direct Testimony of Kenneth Lee Elder, Jr**

**March 2022**

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1                                   **I. INTRODUCTION AND QUALIFICATIONS**

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

4   A. My name is Kenneth Lee Elder, Jr. My business address is 825 NE Multnomah  
5   Street, Suite 600, Portland, Oregon 97232. My position is Load Forecasting  
6   Manager.

7   **Q. Briefly describe your education and professional experience.**

8   A. I have a Bachelor's Degree in Agriculture Business from Tarleton State University  
9   and a Master's Degree in Agricultural and Resource Economics from Colorado State  
10   University. I have been employed by PacifiCorp since July 2016, where I have  
11   managed load forecasting and load research activities. From 2008 through 2016, I  
12   was an economist for a natural resource consulting firm. From 2004 through 2008, I  
13   was an economist for the University of Alaska Fairbanks.

14   **Q. Have you testified in previous regulatory proceedings?**

15   A. Yes. I have previously filed testimony on behalf of the Company in regulatory  
16   proceedings in Utah.

17                                   **II. PURPOSE OF TESTIMONY**

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

19   A. The purpose of my testimony is to explain how the Company developed the forecasts  
20   of the number of customers, kilowatt-hour (kWh) sales at the meter (sales), system  
21   loads and system peak loads at the system input level (loads), and number of bills by  
22   rate schedule for the 12-month period ending December 31, 2023.

1 **III. OVERVIEW**

2 **Q. When did the Company prepare the sales and load forecast used in this filing?**

3 A. The sales and load forecast used in this filing was completed in May 2021. The  
4 May 2021 sales and load forecast is the most recent forecast of sales and loads  
5 prepared by the Company.

6 **Q. How did the Company use the May 2021 sales and load forecast in this filing and**  
7 **in the Company's concurrent 2023 Transition Adjustment Mechanism (2023**  
8 **TAM) filing?**

9 A. The May 2021 load forecast was used by Ms. Sherona L. Cheung to calculate the  
10 inter-jurisdictional allocation factors. The sales forecast by rate schedule was used by  
11 Mr. Robert M. Meredith to allocate costs between customer classes and to design  
12 rates that correctly reflect the cost of service. The load forecast was also used by the  
13 Company to calculate net power costs in the 2023 TAM filing.<sup>1</sup>

14 **Q. Please provide a general overview of the Company's sales and load forecast**  
15 **methodology.**

16 A. The Company's methodology consists of first developing a forecast of monthly sales  
17 by customer class and monthly peak load by state. This sales forecast becomes the  
18 basis of the load forecast by adding line losses, meaning kWh sales levels are  
19 grossed-up to a generation or "input" level. The monthly loads are then spread to  
20 each hour based on the peak load forecast and typical hourly load patterns to produce  
21 the hourly load forecast.

---

<sup>1</sup> *In the matter of PacifiCorp, dba Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400 (Mar. 1, 2022).

1 **Q. Please provide a summary of the forecasted energy sales for 2023.**

2 A. Table 1 provides the forecasted energy sales in megawatt-hours (MWh) for the 12-  
3 month period ending December 31, 2023 that is used in this general rate case  
4 (2023 GRC or 2023 Rate Case).

**Table 1 - Test Period Sales Forecast (MWh)**

	<b>2023 GRC (CY 2023)</b>	
	<b>Total Company</b>	<b>Oregon</b>
<b>Residential</b>	<b>17,109,240</b>	<b>5,780,833</b>
<b>Commercial</b>	<b>20,419,167</b>	<b>6,321,549</b>
<b>Industrial</b>	<b>18,619,291</b>	<b>1,465,509</b>
<b>Irrigation</b>	<b>1,475,938</b>	<b>333,716</b>
<b>Lighting</b>	<b>100,089</b>	<b>35,996</b>
<b>Total</b>	<b>57,723,723</b>	<b>13,937,602</b>

5 **IV. COMPARISONS TO PRIOR SALES FORECASTS**

6 **Q. How does the total-company sales forecast for 2023 compare to the sales forecast**  
7 **used in the last general rate case, docket UE 374 (2021 Rate Case)?<sup>2</sup>**

8 A. As shown in Table 2, total-company 2023 forecast sales are 2.5 percent higher than  
9 2021 forecast sales used in the 2021 Rate Case. The difference in the forecasts is  
10 attributable to an increase in residential, commercial, irrigation and lighting load.  
11 The growth in the residential class is attributable to strong historical class sales over  
12 recent years, while the growth in the commercial class is related to data centers. The  
13 industrial class decrease in the forecast is primarily attributable to a decline in  
14 commodity prices in 2020.

---

<sup>2</sup> *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).*



**Table 2 - Total Company Sales Comparison (MWh)**

	<b>Previous GRC CY 2021</b>	<b>Current GRC CY 2023</b>	<b>Percentage Change</b>
<b>Residential</b>	16,314,413	17,109,240	4.9%
<b>Commercial</b>	19,256,803	20,419,167	6.0%
<b>Industrial</b>	19,176,292	18,619,291	-2.9%
<b>Irrigation</b>	1,469,416	1,475,938	0.4%
<b>Lighting</b>	99,688	100,089	0.4%
<b>Total</b>	56,316,612	57,723,723	2.5%

1 **Q. How does the Oregon sales forecast for 2023 compare to the sales forecast for the**  
2 **2021 Rate Case?**

3 **A.** As shown in Table 3, the 2023 Oregon sales forecast has increased by approximately  
4 1.6 percent from the 2021 sales forecast used in the 2021 Rate Case. The commercial  
5 class increase reflects the continuing expansion of data centers in Oregon. The  
6 increase in residential class sales is driven by customer growth offset by a decline in  
7 use-per-customer. The decline in the industrial load reflects the continuing decline in  
8 industrial sales in the Company’s Oregon service territory.

**Table 3 - Oregon Sales Comparison (MWh)**

	<b>Previous GRC CY 2021</b>	<b>Current GRC CY 2023</b>	<b>Percentage Change</b>
<b>Residential</b>	5,671,134	5,780,833	1.9%
<b>Commercial</b>	5,996,343	6,321,549	5.4%
<b>Industrial</b>	1,682,735	1,465,509	-12.9%
<b>Irrigation</b>	333,381	333,716	0.1%
<b>Lighting</b>	32,935	35,996	9.3%
<b>Total</b>	13,716,528	13,937,602	1.6%

9 **V. FORECAST METHODOLOGY**

10 **Q. What aspects of the sales and load forecast methodology do you address?**

11 **A.** First, I describe the updates to the data and assumptions used to produce the sales and  
12 load forecasts. Second, I describe the forecasting approach used to develop customer  
13 forecasts for all classes. Third, I describe the forecasting approach for developing

1 monthly sales for the residential, commercial, industrial, irrigation, and lighting  
2 customer classes. Fourth, I describe how the hourly load forecast is developed. Fifth,  
3 I describe how the forecasts by rate schedule for sales and number of bills are  
4 developed.

5 **A. Summary of Changes in Forecast Data and Assumptions**

6 **Q. Please summarize major updates used to produce the 2023 forecast as compared**  
7 **to the forecast used in the 2021 Rate Case.**

8 A. The Company updated many of its data inputs when compared to the forecast prepared  
9 for the 2021 Rate Case. For each of these updates, the Company used the most recent  
10 information available.

11 1. For Oregon, the residential and commercial classes use a historical data period  
12 of January 2000 through February 2021. The historical data period used to  
13 develop the industrial monthly sales is from January 2008 through  
14 February 2021. The irrigation class uses the historical data period of January  
15 2001 through February 2021, while the lighting class uses the historical data  
16 period of April 2006 through February 2021.

17 2. The Company updated the historical data period used to develop the monthly  
18 peak forecasts to include January 2008 through December 2020.

19 3. The Company updated the economic drivers for each of the Company's  
20 jurisdictions using IHS Markit data released in March 2021.

21 4. The Company updated the forecast of individual industrial and commercial  
22 customer usage based on the best information available as of February 2021.

23 5. The time period used to calculate normal weather was defined as the 20-year

1 time period of 2001 through 2020.

2 6. The Company rolled forward the line loss calculation to the five-year period  
3 ending December 2020.

4 7. The data used to develop temperature splines was rolled forward based on  
5 available customer class hourly data (October 2015 through September 2020).

6 8. The Company used the residential use-per-customer model with appliance  
7 saturation and efficiency results released in July 2020.

8 **Q. Have there been any updates to the forecast methodology used in this case**  
9 **compared to the forecast prepared for the 2021 Rate Case, and the 2021 TAM**  
10 **(docket UE 375)?<sup>3</sup>**

11 A. Yes. The load forecast for the 2023 Rate Case and the 2023 TAM incorporates the  
12 Company's expectations for building electrification. Building electrification  
13 projections were based on equipment saturations, consumption information,  
14 regulatory conventions, and legislative initiatives in the Company's service territory.

15 **B. Customer Forecast Methodology**

16 **Q. How are the forecasts for the number of customers for each class developed?**

17 A. For the residential class, the Company forecasts the number of customers using IHS  
18 Markit's forecast of number of households or population as the major driver. For the  
19 commercial class, the Company forecasts the number of customers using households  
20 or population as the major economic driver. For the industrial, irrigation and street  
21 lighting classes, the customer forecasts are relatively static and developed using time  
22 series or regression models without any economic drivers.

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<sup>3</sup> *In the matter of PacifiCorp, dba Pacific Power, 2021 Transition Adjustment Mechanism, Docket No. UE 375, Order No.20-392 (Oct. 30, 2020).*

1           **C.     Monthly Sales Forecast Methodology**

2           **Q.     What methodology does the Company use to forecast the residential class sales?**

3           A.     The Company develops the residential sales forecasts as a product of two separate  
4           forecasts: (1) the number of customers—as described above; and (2) sales-per-  
5           customer. The Company models sales-per-customer for the residential class through  
6           a Statistically Adjusted End-Use (SAE) model, which combines the end-use modeling  
7           concepts with traditional regression analysis techniques. Major drivers of the SAE-  
8           based residential model are heating and cooling-related variables, equipment shares,  
9           saturation levels and efficiency trends, and economic drivers such as household size,  
10          income, and energy price.

11          **Q.     What methodology does the Company use to forecast the commercial class sales?**

12          A.     For the commercial class, the Company forecasts sales using regression analysis  
13          techniques with non-manufacturing employment or non-farm employment, as the  
14          economic drivers, in addition to weather-related variables. Also, similar to how the  
15          Company forecasts its largest industrial customers, data center forecasts are based on  
16          input from the Company's regional business managers (RBMs). The treatment of  
17          data centers is similar to large industrial customer sales, which is discussed below.

18          **Q.     How does the Company forecast sales for the industrial customer class?**

19          A.     The majority of industrial customers are modeled using regression analysis with  
20          manufacturing employment or an industrial production index as the major economic  
21          driver. For a small number of industrial customers, the largest on the Company's  
22          system, the Company individually forecasts these customers based on input from the  
23          customer and information provided by the RBMs.

1 **Q. What methodology does the Company use for the irrigation and lighting sales**  
2 **forecasts?**

3 A. For the irrigation class, the Company forecasts sales using regression analysis  
4 techniques based on historical sales volumes and weather-related variables. Monthly  
5 sales for lighting are forecast using regression analysis techniques based on historical  
6 sales volumes and a light-emitting diode lighting adoption curve.

7 **D. Hourly Load Forecast**

8 **Q. Please outline how the hourly load forecast is developed.**

9 A. After the Company develops the forecasts of monthly energy sales by customer class,  
10 a forecast of hourly loads is developed in two steps.

11 First, monthly peak forecasts are developed for each state. The monthly peak  
12 model uses historical peak-producing weather for each state and incorporates the  
13 impact of weather on peak loads through several weather variables that drive heating  
14 and cooling usage. These weather variables include the average temperature on the  
15 peak day and lagged average temperatures from up to two days before the day of the  
16 peak. This forecast is based on average monthly historical peak-producing weather  
17 for the 20-year period 2001 through 2020.

18 Second, the Company develops hourly load forecasts for each state using  
19 hourly load models that include state-specific hourly load data, daily weather  
20 variables, the 20-year average temperatures identified above, a typical annual weather  
21 pattern, and day-type variables such as weekends and holidays as inputs to the model.  
22 The hourly loads are adjusted to match the monthly peaks from the first step above.

1 Also, the hourly loads are adjusted so the monthly sum of hourly loads equals  
2 monthly sales plus line losses.

3 **Q. How are monthly system coincident peaks derived?**

4 A. After the hourly load forecasts are developed for each state, hourly loads are  
5 aggregated to the total system level. The system coincident peaks can then be  
6 identified, as well as the contribution of each jurisdiction to those monthly peaks.

7 **E. Forecasts by Rate Schedule**

8 **Q. Were any additional forecasts created for these proceedings?**

9 A. Yes. As mentioned earlier, Mr. Meredith requires two additional forecasts that are  
10 based on the kWh sales forecast and the number of customers forecast. Once the  
11 kWh sales forecast is complete, it must be applied to individual rate schedules to  
12 forecast kWh sales by rate schedule. In addition, the forecast of number of customers  
13 by rate schedule must be expressed in number of bills.

14 **Q. How are rate schedule level forecasts produced?**

15 A. The Company develops this forecast in two steps. First, the Company forecasts test  
16 year sales by rate schedule. Then the Company proportionally adjusts the rate  
17 schedule sales forecasts so that the total across the rate schedules matches the  
18 customer class forecast.

19 **Q. How does the Company forecast the number of bills for each rate schedule?**

20 A. The forecast of the number of bills for each rate schedule follows the same process as  
21 the sales forecast for each rate schedule. First, the Company forecasts the number of  
22 bills by class and by rate schedule. Then, the Company proportionally adjusts the

1 forecasted number of bills by rate schedule so that the total number of bills across the  
2 rate schedules matches the customer class forecasted number of bills.

3 **Q. Does this conclude your direct testimony?**

4 **A. Yes.**

Docket No. UE 399  
Exhibit PAC/1000  
Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Direct Testimony of Sherona L. Cheung**

**March 2022**



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## ATTACHED EXHIBITS

Exhibit PAC/1001—Revenue Requirement Summary

Exhibit PAC/1002—Oregon Results of Operations – December 2023

Confidential Exhibit PAC/1003—PacifiCorp’s Property Tax Estimation Procedure

Confidential Exhibit PAC/1004—Wage and Employee Benefits Wage Escalators

Confidential Exhibit PAC/1005—IHS Markit Escalation Indices

Direct Testimony of Sherona L. Cheung

Confidential Exhibit PAC/1006—Transmission Wheeling - Facebook Support

Confidential Exhibit PAC/1007—Bridger Mine Reclamation Support

Confidential Exhibit PAC/1008— Regulator Assets & Liabilities Adjustment Support

1                   **I.           INTRODUCTION AND QUALIFICATIONS**

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

4   A.   My name is Sherona L. Cheung, and my business address is 825 NE Multnomah  
5       Street, Suite 2000, Portland, OR 97232. I am currently employed as Revenue  
6       Requirement Manager for PacifiCorp.

7   **Q.    Briefly describe your educational and professional background.**

8   A.   I earned my Bachelor of Commerce with a major in Finance in 2008. In 2011, I  
9       obtained my Certified Management Accounting designation in British Columbia,  
10      Canada. In addition to my formal education, I have attended several utility  
11      accounting, ratemaking, and leadership seminars and courses. I have been employed  
12      by the Company since May of 2013 in various positions within the regulation  
13      organization. In April 2021, I was promoted to Revenue Requirement Manager.

14   **Q.    What are your responsibilities as Revenue Requirement Manager?**

15   A.   My primary responsibilities include overseeing the calculation of PacifiCorp's  
16      revenue requirement and the preparation of various regulatory filings in Washington,  
17      Oregon, and California. I am also responsible for the calculation and reporting of  
18      PacifiCorp's regulated earnings and the application of the inter-jurisdictional cost  
19      allocation methodologies.

20   **Q.    Have you testified in previous regulatory proceedings?**

21   A.   Yes. I have previously provided testimony in California and Washington.

1                   **II.           PURPOSE AND SUMMARY OF TESTIMONY**

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

3   A.    My direct testimony addresses the calculation of the Company's Oregon-allocated  
4        revenue requirement, excluding net power costs (NPC), and the revenue increase  
5        requested in the Company's filing. Specifically, I provide testimony on the following:

- 6        •    The calculation of the \$84.4 million revenue increase requested in this general  
7            rate case (GRC) representing the increase over current rates required for the  
8            Company to recover its Oregon non-NPC revenue requirement of  
9            \$1,044.8 million. The Company currently recovers its NPC through the  
10          Transition Adjustment Mechanism (TAM).
- 11       •    The selection of the historical period of the 12 months ended June 2021 (Base  
12          Period) as the basis for the test period in this proceeding.
- 13       •    The development of the forecast test year in this case, which is the 12-month  
14          period ending December 31, 2023 (Test Period).
- 15       •    The treatment of forecasted capital additions included in the revenue requirement  
16          calculations, which have been limited to projects placed in service before January  
17          1, 2023, the beginning of the Test Period.
- 18       •    The presentation of the normalized results of operations for the Test Period  
19          demonstrating that under current rates the Company will earn an overall return  
20          on equity (ROE) in Oregon of 4.7 percent, which is less than half of the  
21          Company's currently authorized ROE of 9.5 percent and the 9.8 percent  
22          requested by the Company and supported by Ms. Ann E. Bulkley in this  
23          proceeding.

1 **Q. How have you organized your testimony?**

2 A. I have divided my testimony into three sections. I discuss the development of the  
3 Company's revenue requirement, including the base and test periods, in Section III,  
4 Revenue Requirement. In Section IV, Inter-jurisdictional Allocations, I address the  
5 allocation methodology used in this filing. In Section V, Oregon Results of  
6 Operations, I provide a description of the Oregon Results of Operations, including a  
7 review of the information contained in Exhibit PAC/1002.

8 **III. REVENUE REQUIREMENT**

9 **Q. What is the revenue requirement to achieve the requested ROE in this case?**

10 A. At current rate levels, the Company will earn an overall ROE in Oregon of  
11 4.7 percent during the Test Period. This return is less than the 9.5 percent ROE  
12 authorized in the Company's 2021 general rate case, docket UE 374 (2021 Rate  
13 Case).<sup>1</sup> The Company is proposing to change the authorized ROE in this case to  
14 9.8 percent. A 9.8 percent ROE produces a non-NPC revenue requirement of  
15 \$1,044.8 million based on the 2020 PacifiCorp Inter-Jurisdictional Allocation  
16 Protocol (2020 Protocol). Exhibit PAC/1001 provides a summary of the Company's  
17 Oregon-allocated results of operations for the Test Period. Exhibit PAC/1002  
18 provides the supporting details and calculations and is discussed in greater detail later  
19 in my testimony.

20 **Q. Please explain how you have treated NPC in this filing.**

21 A. As noted above, the Company recovers its NPC through the TAM, which was

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<sup>1</sup> *In the matter of PacifiCorp dba Pacific Power Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 31 (Dec. 18, 2020). The Commission set an overall rate of return at 7.137 percent and an authorized return on equity of 9.5 percent.

1 concurrently filed with this general rate case<sup>2</sup> on March 1, 2022, for calendar year  
2 2023 NPC. To model the non-NPC revenue requirement for this case, the Company  
3 first computed an overall Test Period revenue requirement including the NPC as filed  
4 in the TAM and then removed the NPC components from the overall price change.  
5 This approach is required to compute certain non-NPC components of the Test Period  
6 revenue requirement that are impacted by NPC-related items, such as the embedded  
7 cost differential (ECD), and various revenue-sensitive items. Details supporting the  
8 overall revenue requirement and the breakout between the TAM and general rate case  
9 are provided in Exhibit PAC/1001. Page 1 of Exhibit PAC/1001 also shows the  
10 division of revenue requirement between the TAM and general rate case components,  
11 and the resulting general-rate-case-related price change requested in this case.

12 **A. Base Period**

13 **Q. Why did the Company use July 2020 through June 2021 as the historical basis,**  
14 **or Base Period, for developing the Test Period in this case?**

15 A. The Company selected the 12-month period ended June 2021 as the historical basis  
16 for this case because it was the most recent total-company data available for inter-  
17 jurisdictional allocations to achieve a filing date of March 1, 2022. The Company  
18 audits and extracts total-company accounting information with the data components  
19 necessary for state allocations on a semi-annual basis for the 12-month period ending  
20 June and December each year. This semi-annual data extract and review procedure is  
21 a key control measure to ensure the accuracy and reliability of the data, which serves

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<sup>2</sup> *In re the matter of PacifiCorp d/b/a Pacific Power 2023 Transition Adjustment Mechanism*, Docket No. UE 400 Advice No. 22-003 Initial Filing (Mar. 1, 2022).

1 as the basis for each of the Company's results of operations and general rate case  
2 filings.

3 **Q. Why was a March 1, 2022, filing date for this general rate case necessary?**

4 A. In Order 09-274, the Public Utility Commission of Oregon (Commission) adopted a  
5 stipulation establishing guidelines for future TAM filings, including the following  
6 provision:

7 In all future filings after UE 207 in a year in which the Company  
8 files a general rate case, the TAM will be included in or processed  
9 concurrently with the general rate case filing. *In future filings after*  
10 *UE 207, the Company agrees that both filings will be made no later*  
11 *than March 1 to allow for a January 1 rate effective date.*<sup>3</sup>

12 PacifiCorp is filing this general rate case and the concurrent TAM on March 1, in  
13 adherence to the requirement set forth in Order 09-274.

14 **Q. When will calendar year 2021 total-company data become available on an**  
15 **inter-jurisdictional allocation basis?**

16 A. Only once total-company data is audited does it become available to begin analysis  
17 on an inter-jurisdictional allocation basis. Because of the unique complexities the  
18 Company faces as a multi-jurisdictional utility, additional time is necessary once  
19 total-company financial data is finalized to ensure state-allocated data is accurate.  
20 Due to these complex steps, calendar year 2021 data will not be available for use as  
21 the basis of a forecast test period until the end of April 2022, almost two months after  
22 this general rate case is filed.

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<sup>3</sup> *In the matter of PacifiCorp dba Pacific Power 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, Appendix A at 13 (July 16, 2009) (emphasis added).

1           **B.     Test Period**

2           **Q.     What Test Period did the Company use to determine revenue requirement in this**  
3           **case?**

4           A.     The forecast Test Period used by the Company in this proceeding is the 12 months  
5           ending December 31, 2023.

6           **Q.     Why did the Company choose the year ending December 31, 2023, as the Test**  
7           **Period?**

8           A.     The Test Period in this case was selected to best reflect the conditions during the time  
9           the new rates will be in effect. The requested rate effective date in this case is  
10          January 1, 2023, which matches the start of the Test Period used by the Company in  
11          the calculation of the revenue requirement. The Test Period in this general rate case  
12          also matches the test period used in the development of the NPC filed in the  
13          concurrent TAM.

14          **Q.     Please explain how the Company developed the revenue requirement for the Test**  
15          **Period.**

16          A.     Revenue requirement preparation began with historical accounting information; in  
17          this case, the Company used the 12 months ended June 30, 2021. Each of the revenue  
18          requirement components in the Base Period was analyzed to determine if a  
19          normalizing ratemaking adjustment was warranted to reflect normal operating  
20          conditions. The historical information was then adjusted to recognize known,  
21          measurable, and anticipated events. Previous Commission-ordered adjustments are  
22          also included as part of the Company's revenue requirement calculation for the Test  
23          Period.



1 **Q. What is the significance of beginning with historical information?**

2 A. The Company begins with historical accounting information and makes discrete  
3 adjustments to arrive at the Test Period revenue requirement. Beginning with  
4 historical information provides a solid foundation that is readily available for audit by  
5 all who wish to participate in the case. Individual adjustments are also available for  
6 review, and regulators and intervenors may determine each adjustment's relevance  
7 and accuracy.

8 **Q. Please summarize the process used to adjust the historical accounting  
9 information to reflect Test Period revenues and costs.**

10 A. Revenues are adjusted by applying the current Commission-approved tariff rates to  
11 the Test Period load projection. NPC are developed using the Aurora model from  
12 Energy Exemplar. The results of the Aurora run for the Test Period are embedded in  
13 the results for calculation purposes only; as previously mentioned, recovery of these  
14 costs is sought through the TAM filing. Historical operations and maintenance  
15 (O&M) expenses, excluding NPC, are split into labor and non-labor components.  
16 Non-labor costs are adjusted for inflation using inflation indices developed  
17 specifically for electric utilities provided by Information Handling Services (IHS  
18 Markit, previously Global Insight) and for other distinct changes required to reflect  
19 conditions expected during the Test Period. Historical labor costs are also adjusted  
20 for contractual and anticipated increases through the end of the Test Period.

21 **Q. Does the Company rely solely on its own projections of future cost increases?**

22 A. No. For example, the adjustment made to account for inflation between the historical  
23 period and the Test Period relies on inflation indices published by IHS Markit.

1 Updates to pension and benefits expenses are made in accordance with forecasts from  
2 actuarial reports, while labor expenses governed by union contracts are  
3 walked-forward to Test Period levels using contractual labor increase percentages.

4 **Q. How has the Company addressed areas where cost increases are different than**  
5 **inflation?**

6 A. The Company's business units were asked to identify areas where budgets were  
7 significantly different than historical amounts, adjusted for wage increases and  
8 inflation. When differences were identified, the business units were asked to provide  
9 support for changes in the number, or frequency, of activities. An example of this  
10 type of adjustment is the Wildfire and Vegetation Management Expenses adjustment  
11 (adjustment page 4.11). Adjustments of this nature are necessary because inflation  
12 indices account for cost increases on existing units of production, not changes in  
13 volume or processes.

14 **Q. Has the calculation of federal income tax expense been changed since the last**  
15 **general rate case?**

16 A. No; federal income tax expense for ratemaking is calculated using the same  
17 methodology that the Company uses in preparing its filed income tax returns. As  
18 with the previous general rate case, the federal income tax rate is reflected at  
19 21 percent, which represents the current enacted federal income tax rate.

20 **Q. Are changes being proposed to depreciable lives in this case?**

21 A. Yes. This filing includes updated depreciation expense for Colstrip  
22 Units 3 and 4, Craig Unit 2, and Hayden Units 1 and 2. For these specific coal-fired  
23 generation units, the Company is proposing to revise the end of their depreciable lives

1 to align with each unit's planned retirement dates as outlined in the Company's 2021  
2 Integrated Resource Plan (IRP). For all assets other than the specific units identified  
3 above, however, depreciation expense reflected in the Company's revenue  
4 requirement calculation is based on approved depreciation rates by the Commission  
5 in the Company's 2018 Depreciation Study<sup>4</sup> and in the Company's 2021 Rate Case.  
6 Please see the direct testimony of Ms. Joelle R. Steward for discussion on the  
7 Company's proposal for these units. I will address how this update is reflected in the  
8 derivation of the Test Period revenue requirement later in my testimony.

9 **Q. Is PacifiCorp including the TB Flats Wind Project in this GRC?**

10 A. Yes, while the prudence of PacifiCorp's investment in the TB Flats Wind Project was  
11 approved in the 2021 Rate Case,<sup>5</sup> only a portion of the costs were in-service at the  
12 time of the rate effective date. The remaining costs are being brought into rates at this  
13 time.

14 **Q. What is the impact of TB Flats?**

15 A. The Company has included in rate base an additional \$453.1 million total-company,  
16 or \$118.1 million Oregon-allocated, capital placed in-service since  
17 December 31, 2020.

18 **Q. Are there any additional costs that have been included in this case beyond what  
19 was approved in the last GRC?**

20 A. Yes. The total project cost in this proceeding is approximately \$15.8 million higher  
21 overall on a total-company basis when compared to the 2021 rate case. Please refer

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<sup>4</sup> *In the Matter of PacifiCorp dba Pacific Power Application for Authority to Implement Revised Depreciation Rates*, Docket No. UM 1968, Application (Sept. 13, 2018).

<sup>5</sup> *In the Matter of PacifiCorp dba Pacific Power, Application for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 50 (Dec. 18, 2020).

1 to the direct testimony of Mr. Timothy J. Hemstreet for further information on the  
2 reasons impacting project cost outcomes.

3 **Q. Please explain when the TB Flats Wind Project came online and PacifiCorp's**  
4 **deferral of costs since the online date.**

5 A. As noted above, a portion of the TB Flats Wind Project was placed in-service in  
6 December 2020. That portion of the capital costs was included in rates that became  
7 effective on January 1, 2021. The remainder of the TB Flats Wind Project was then  
8 placed into commercial operation by July 2021. Upon completion of the remainder of  
9 the project, the Company filed an application for approval of deferred accounting to  
10 allow it to match the costs and benefits of TB Flats, a renewable resource, for later  
11 inclusion in rates.<sup>6</sup> This deferral records the costs and benefits of the TB Flats Wind  
12 Project that was not placed in-service by December 2020, until these costs and  
13 benefits can be fully reflected in customer rates. In this case, the Company is seeking  
14 approval to begin amortization of the deferred cost and benefits. Details on the  
15 deferral calculation and the Company's proposal to amortize the deferred costs and  
16 benefits is further discussed later in my testimony under Section V., F. Tab 8 – Rate  
17 Base Adjustments, and supported by my Exhibit PAC/1002 on the corresponding  
18 pages outlining calculations and supporting workpapers for adjustment 8.14.

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<sup>6</sup> *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120, Docket No. UM 2186, Application (Jul. 27, 2021).*

1 **Q. How is the Decommissioning Cost Recovery Adjustment and Coal Removal**  
2 **Mechanism docket<sup>7</sup> reflected in the revenue requirement in this case?**

3 A. In July 2021, the Company filed an application under docket UM 2183, requesting an  
4 order from the Commission authorizing a new tariff to collect an increase to estimated  
5 decommissioning costs of coal-fired generation resources (including remediation and  
6 closure costs) reflected in independent estimates conducted by Kiewit Engineering  
7 Group, Inc. The application also sought approval of a coal removal mechanism to  
8 reduce regulatory lag when coal units are no longer used to serve Oregon customers.  
9 Because this on-going docket addresses the recovery of costs associated with coal-  
10 fired generation resources decommissioning and removal, these costs are not included  
11 as part of revenue requirement in this general rate case.

12 **Q. What components related to wildfire and vegetation management are included in**  
13 **the revenue requirement in this case?**

14 A. Wildfire mitigation capital, wildfire mitigation vegetation management and  
15 vegetation management O&M expenses are included in this case as outlined in the  
16 direct testimony of Mr. Allen Berreth. Capital projects for wildfire mitigation that  
17 have been completed and placed in-service by June 2021 are embedded in the capital  
18 balances for the Base Period. Related projects forecasted to be placed in-service after  
19 the Base Period are reflected in incremental adjustment 8.4 in my exhibits. Wildfire  
20 mitigation capital and O&M expenses included in this case will set the baseline for  
21 recovery of wildfire mitigation costs in Oregon rates. In this case, the Company is  
22 forecasting wildfire mitigation capital projects to be placed in-service through

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<sup>7</sup> *In the Matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement a Decommissioning Cost Recovery Adjustment and Coal Removal Mechanism, Docket No. UM 2183 (Jul. 8, 2021).*

1 December 2022 of approximately \$34.7 million on an Oregon-allocated basis.  
2 Wildfire mitigation O&M and vegetation management O&M are updated to forecast  
3 levels for the Test Period through adjustment 4.11. Test Period wildfire mitigation  
4 O&M is expected to be approximately \$19.7 million and non-wildfire vegetation  
5 management O&M is expected to be approximately \$50.3 million on an Oregon-  
6 allocated basis. Page 4.11.1 in my Exhibit PAC/1002 provides a breakdown of these  
7 expenses between wildfire mitigation-related vegetation management expenses, non-  
8 wildfire vegetation management expenses, and wildfire-related non-vegetation  
9 management expenses.

10 Incremental wildfire mitigation capital and related O&M expenditures beyond  
11 what is included in rates set in this rate case will be recovered through a new  
12 automatic adjustment clause, as described by Ms. Steward. Non-wildfire vegetation  
13 management expenses over and above levels included in rates would be subject to  
14 recovery under the proposed mechanism detailed in Mr. Berreth's testimony.

15 **Q. How has the Company treated forecast capital additions to electric plant in**  
16 **service in this filing?**

17 A. The Company has included capital additions to plant in-service through  
18 December 31, 2022, rather than through the end of the forecast Test Period and the  
19 rate effective period, which would be December 31, 2023. This treatment is  
20 consistent with the Company's 2010,<sup>8</sup> 2012,<sup>9</sup> 2013,<sup>10</sup> and 2021<sup>11</sup> Rate Cases.

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<sup>8</sup> 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).

<sup>9</sup> 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).

<sup>10</sup> 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).

<sup>11</sup> See Order No. 20-473.

1 **Q. What changes are reflected in this rate case for the Klamath Hydroelectric**  
2 **Facilities?**

3 A. PacifiCorp is a signatory to the Klamath Hydroelectric Settlement Agreement  
4 (KHSA), which provides for the transfer of four main-stem Klamath Hydroelectric  
5 Project developments, currently licensed to PacifiCorp, to a third-party dam removal  
6 entity that will pursue their removal. Consistent with the KHSA, depreciation rates  
7 for the Klamath assets were previously approved by the Commission to provide for  
8 full depreciation of the Klamath assets by December 31, 2019, in anticipation of the  
9 target date for dam removal of 2020 established in the KHSA. The Federal Energy  
10 Regulatory Commission (FERC) is currently evaluating the proposal to transfer the  
11 license for certain Klamath developments to the Klamath River Renewal Corporation,  
12 the dam removal entity under the KHSA. The timing of when FERC will transfer the  
13 license, and when PacifiCorp's operations would ultimately cease, remains uncertain.  
14 As the current project licensee, PacifiCorp's obligations under the license and FERC  
15 regulations continue to require capital investments to support ongoing project  
16 operations, ensure compliance with dam safety and other regulatory requirements,  
17 and to make other capital expenditures necessary to fulfill obligations under the  
18 KHSA to mitigate impacts of ongoing project operations.

19 Because the timing of license transfer and the cessation of generation from the  
20 Klamath assets remains uncertain, PacifiCorp has continued to apply a depreciation  
21 rate of 20 percent per year for ongoing capital additions to the Klamath assets,  
22 consistent with the depreciation assumption in approved rates that resulted from  
23 Company's 2021 Rate Case.

1                    **IV.            INTER-JURISDICTIONAL ALLOCATIONS**

2    **Q.    What methodology did the Company use to calculate the Oregon-allocated**  
3    **revenue requirement in this case?**

4    A.    The Company's Oregon-allocated revenue requirement is calculated using the 2020  
5    Protocol, which was approved by the Commission in docket UM 1050 on  
6    January 23, 2020.<sup>12</sup> This is the same allocation methodology used in the Company's  
7    2021 Rate Case.

8                    **V.            OREGON RESULTS OF OPERATIONS**

9    **Q.    Please describe Exhibit PAC/1002.**

10   A.    Exhibit PAC/1002, which was prepared under my direction, is the Company's Oregon  
11   results of operations report (Report). As previously explained, the Base Period for the  
12   Report is the 12 months ended June 30, 2021, which has been normalized and used to  
13   calculate the revenue requirement for the Test Period, the 12 months ending  
14   December 31, 2023. The Report provides totals for revenue, expenses, depreciation,  
15   NPC, taxes, rate base, and loads in the Test Period. The Report presents operating  
16   results for the Test Period in terms of both return on rate base and ROE.

17   **Q.    Please describe how Exhibit PAC/1002 is organized.**

18   A.    The Report is organized into sections marked with tabs as follows:

- 19        •    Tab 1 Summary contains a summary of Oregon-allocated results according to the  
20            2020 Protocol. Page 1.1 breaks out the non-NPC results and calculates the revenue  
21            increase the Company is requesting as part of this general rate case (column 5).  
22            Page 1.2 contains a summary of the general rate case request.

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<sup>12</sup> See *In the Matter of PacifiCorp d/b/a Pacific Power, Petition for Approval of the 2020 Inter-Jurisdictional Allocation Protocol, Docket No. UM 1050, Order No. 20-024 (Jan. 23, 2020)*.



- 1           • Tab 2 Results of Operations details the Company’s overall revenue requirement,  
2           showing unadjusted costs for the Base Period and fully normalized results of  
3           operations for the Test Period by FERC account and 2020 Protocol allocation  
4           factor.
- 5           • Tabs 3 through 8 provide supporting documentation for the normalizing  
6           adjustments required to reflect on-going costs of the Company.
- 7           • Tab 9 provides the derivation of the ECD included in this case.
- 8           • Tab 10 contains the calculation of the 2020 Protocol allocation factors. Factors in  
9           this case are based on the load forecast through December 2023 and pro forma  
10          account balances.
- 11          • Tabs B1 through B20 contain the historical data for the Base Period and are  
12          organized by major FERC function.

13          **A.     Tab 3 – Revenue Adjustments**

14          **Q.     Please describe the information contained within Tab 3 Revenue Adjustments.**

15          A.     Tab 3 begins with the Revenue Adjustment Index which contains a brief overview of  
16          the assumptions used to project Test Period revenues and a list of each normalization  
17          adjustment included in this section of the exhibit. The numerical summary (page  
18          3.0.2) identifies each adjustment made to actual revenues and each adjustment’s  
19          impact on the case. Each column has a numerical reference to a corresponding page  
20          in the Report, which contains a lead sheet showing the affected FERC account(s),  
21          allocation factor(s), dollar amount, and a description of the adjustment.

22          **Q.     Please describe each adjustment made to revenue in Tab 3.**

23          A.     **Pro Forma Revenue (page 3.1)** – This adjustment normalizes general business

1 revenues by adjusting to the pro forma revenue level for the Test Period based on  
2 forecasted loads. Page 3.1.4 shows a breakout of the TAM and general rate case  
3 revenues.

4 **Renewable Energy Certificate (REC) Revenues (page 3.2)** – This adjustment  
5 removes all REC revenue and REC deferrals booked during the 12 months ended  
6 June 2021. Most of Oregon’s share of RECs is banked for compliance; however, not  
7 all RECs meet the Oregon Renewable Portfolio Standard (RPS) qualifications.  
8 Oregon’s revenue from RPS ineligible RECs that are sold are passed back to  
9 customers through the Oregon property sales balancing account per Commission  
10 Order 10-210 in docket UP 260.<sup>13</sup> REC revenues received through Schedule 272 are  
11 accounted for in adjustment 8.6 and addressed separately in later sections of my  
12 testimony under Section V., F. Tab 8 – Rate Base Adjustments.

13 **Wheeling Revenue (page 3.3)** – This adjustment reflects the level of wheeling  
14 revenue for the Test Period by adjusting the actual revenue for normalizing,  
15 annualizing, and pro forma changes.

16 **Ancillary Revenue (page 3.4)** – This pro forma adjustment reflects ancillary revenue  
17 changes that are consistent with the forecast NPC treatment reflected in adjustment  
18 5.1 discussed below. The ancillary revenue booked in the 12 months ended June  
19 2021 is adjusted to reflect the Test Period revenue expected per the terms of contracts  
20 in effect during the Test Period. The corresponding impact on NPC is included in  
21 adjustment 5.1 and in the TAM.

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<sup>13</sup> *In the matter of PacifiCorp, dba Pacific Power Application Approval of Sale of Renewable Energy Credits, Docket No. UP 260, Order No. 10-210 (June 9, 2010).*

1 **Fly Ash Revenue (page 3.5)** – In October 2020, the Company executed a new  
2 contract for sale of fly ash from the Jim Bridger plant. This adjustment annualizes the  
3 increase in fly ash sales revenues in the Base Period to reflect Test Period levels  
4 consistent with new contract terms. Plants with ash sales revenues in the Base Period  
5 are Jim Bridger, Naughton, Craig, and Cholla.

6 **B. Tab 4 – O&M Adjustments**

7 **Q. Please describe the information contained behind Tab 4 O&M Adjustments.**

8 A. Tab 4 includes an O&M Expense Adjustment Index followed by a numerical  
9 summary and the specific adjustments. The O&M Expense Adjustment Index begins  
10 on page 4.0.1 with a brief overview of assumptions used to adjust operation,  
11 maintenance, administrative, and general expenses. The numerical summary (pages  
12 4.0.2 to 4.0.3) identifies each adjustment made to actual expenses and that  
13 adjustment's impact on the case. Each column has a numerical reference to a  
14 corresponding page in the Report, which contains a lead sheet showing the affected  
15 FERC account(s), allocation factor(s), dollar amount and a brief description of the  
16 adjustment.

17 **Q. Please describe the adjustments made to O&M expense in Tab 4.**

18 A. **Miscellaneous General Expense and Revenue (page 4.1)** – This adjustment  
19 removes certain miscellaneous expenses that should have been charged below the line  
20 to non-regulated expenses and recognizes revenues from the Oregon Direct Access  
21 Opt Out amortization.<sup>14</sup> It also reallocates certain gains and losses on property sales  
22 and regulatory expenses to reflect the appropriate allocation.

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<sup>14</sup> *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).*

1       **Wage and Employee Benefits (page 4.2)** – Labor-related costs for the Test Period  
2       are computed by adjusting salaries, incentives, health benefits, and costs associated  
3       with pension, post-retirement benefits, and post-employment benefits for changes  
4       expected beyond the actual costs experienced in the period ended June 2021.  
5       Collective bargaining agreements are used to escalate union wages where increases  
6       are specified,<sup>15</sup> while increases for non-union and exempt employees were based on  
7       actual or anticipated increases. Increases are applied to the wages for each employee  
8       group according to specified or anticipated timelines to arrive at the test year wages  
9       and salaries. The specificity of the Company’s wage escalation is important as  
10      PacifiCorp has nine collective bargaining agreements across six unions of various  
11      sizes. Incentive compensation for non-union employees is included based on the  
12      Company’s forecast of test year expense, adjusted to remove 100 percent of Named  
13      Executive Officers’ (NEO) share, and 50 percent of non-NEO incentives.  
14      Pension-related service expense and other employee benefit costs are adjusted to the  
15      planned expense levels for the Test Period, based on actuarial reports, where  
16      available, or by escalating actual costs. Pension-related non-service expenses are  
17      reflected in adjustment 4.3, described in the following subsection. Please see the  
18      direct testimony of Ms. Nikki L. Kobliha for further discussion of the Company’s  
19      pension expense in this case.  
20              Page 4.2.1 of the Report provides further description of the procedures used to  
21      compute Test Period labor costs. Page 4.2.2 contains a numerical summary of actual

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<sup>15</sup> 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.

1 labor costs in the year ended June 2021 and summarizes the adjustments made to  
2 project costs through the Test Period. This summary is followed by detailed  
3 worksheets on pages 4.2.3 through 4.2.11.

4 **Pension-Related Non-Service Expense (page 4.3)** – This adjustment reflects in the  
5 Test Period pension and post-retirement related non-service expenses at anticipated  
6 2023 levels. These expenses have historically been included in the Company’s results  
7 of operations reports in the Wage and Employee Benefits adjustments (WEBA).  
8 However, because these expenses are no longer eligible for capitalization under  
9 generally accepted accounting principles and are therefore not included in the  
10 Company’s capitalization calculations, they will be accounted for in this new  
11 adjustment going forward. All other pension-related service expenses will continue to  
12 be included in the WEBA adjustment. As discussed in the testimony of Ms. Kobliha,  
13 settlement losses are being amortized over the approximately 20-year average  
14 remaining life expectancy of plan participants.

15 **Remove Non-Recurring Entries (page 4.4)** – This adjustment removes an  
16 accounting entry made to an expense account during the Base Period that is non-  
17 recurring in nature. Accordingly, the transaction amount is removed to normalize  
18 Test Period results. Details on the specific item in the adjustment can be found on  
19 Page 4.4.1.

20 **Insurance Expense (page 4.5)** – In the 2010 Rate Case, the Commission authorized  
21 the Company to establish monthly accruals and associated reserve balances for self-  
22 insurance for transmission and distribution property losses, non-transmission and

1 distribution (Non-T&D) property losses, and third-party liability losses.<sup>16</sup> The  
2 Commission ordered the accrual to begin on April 1, 2011, as a replacement for the  
3 expiration of the Company's captive insurance coverage with Berkshire Hathaway  
4 Energy Company (formerly known as MidAmerican Energy Holdings Company).  
5 The Oregon-allocated monthly accrual for property related losses was based on a 10-  
6 year average of actual property losses, with each year escalated by the Consumer  
7 Price Index to the Test Period. The Oregon-allocated monthly accrual for third-party  
8 liability losses was established based on an annual average of historical insurance  
9 claim payments from April 2005 to December 2009.

10 The adjustment in this case uses the Commission-approved methodology for  
11 self-insurance accruals from the 2010 Rate Case and every case since, updated for  
12 known and measurable changes for both property and liability losses. Premiums for  
13 both property and liability insurance have also been adjusted for known and  
14 measurable changes in the Test Period.

15 Consistent with the treatment from the 2010 Rate Case, the Company is using  
16 a 10- year average of property damages for the self-insurance reserve accrual, using  
17 the most recent 10-year time period. Total-company Non-T&D property insurance  
18 premiums were \$4.9 million for the 12 months ended June 2021 and will be reduced  
19 slightly to \$4.1 million for the Test Period.

20 As of June 2021, the Company's Oregon Property Insurance Reserves balance  
21 is sitting in a debit position. This means that the accruals recorded to this account  
22 have not been sufficient to cover actual expenses incurred. In other words, Oregon

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<sup>16</sup> Order No. 10-473 at 5.

1 customers have been underpaying, to the extent that a significant balance of  
2 \$20.9 million debit balance has accrued in this reserve account. To recover this  
3 expense for which Oregon customers have underpaid, the Company is proposing to  
4 amortize the outstanding balance over 10 years.

5 For third-party liability accrual, while this case continues to be calculating  
6 accrual levels using historical averages, consistent with the approved treatment in the  
7 2010 Rate Case, the third-party liability accrual in this case is calculated based on a  
8 three-year average of historical gross expense net of third-party claim proceeds using  
9 the cash method. Total-company liability insurance premiums were \$8.4 million for  
10 the 12 months ended June 2021 and will increase to \$29.2 million for the Test Period.  
11 The increase in renewed liability insurance premiums effective August 15, 2021, is  
12 attributable to wildfire risk and other factors outside PacifiCorp's control.

13 **Generation Overhaul Expense (page 4.6)** – This adjustment normalizes generation  
14 overhaul expenses in the Base Period using a four-year average methodology. In this  
15 adjustment, overhaul expenses for the years ending June 2018 to June 2021 are  
16 restated to constant dollars to make them comparable prior to averaging.

17 **Revenue-Sensitive Items & Uncollectible Accounts (page 4.7)** – Uncollectible  
18 accounts expense is adjusted to the Test Period level by applying the historical  
19 uncollectible rate (Oregon uncollectible accounts expense in FERC Account 904  
20 divided by Oregon general business revenues) to the normalized general business  
21 revenues in the Test Period. This adjustment also reflects pro forma changes to  
22 Franchise Tax, Resource Supplier Tax, and Public Utility Commission Fees based on  
23 the normalized level of general business revenue for the Test Period. Franchise Tax

1 and Resource Supplier Tax is calculated based on three-year historical average tax  
2 factors derived using historical data from 2019 to 2021. This methodology was  
3 approved in the Company's 2021 Rate Case. The Public Utility Commission Fee will  
4 be updated to the recently approved rate of 0.43 percent in Reply.<sup>17</sup>

5 **Memberships and Subscriptions (page 4.8)** – This adjustment removes expenses in  
6 excess of Commission policy as outlined by the Commission order in docket UE 94.<sup>18</sup>  
7 National and regional trade organizations are recognized at 75 percent.

8 **Meals and Entertainment Adjustment (page 4.9)** – Order 20-473 in the Company's  
9 last general rate case adopted an adjustment of 50 percent of awards expense and  
10 50 percent of meals and entertainment expense recognized as discretionary costs.

11 This adjustment removes the previously disallowed costs from each expense category.

12 **O&M Escalation (page 4.10)** – This adjustment increases non-labor expenses for  
13 projected inflation through the Test Period. Projected increases or decreases in costs  
14 are based on IHS Markit indices, which provide a detailed assessment of the electric  
15 market both historically and into the future. The indices used are based solely on  
16 electric utility costs for materials and services, which exclude labor expense,  
17 according to the Uniform System of Accounts defined by FERC for major electric  
18 utilities. Use of the IHS Markit indices for escalation of non-labor O&M expenses is  
19 consistent with the Company's past rate cases, including its 2021 Rate Case in which  
20 the Commission approved a revenue requirement calculated using these indices.

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<sup>17</sup> *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. 22-062 (Feb. 24, 2022).

<sup>18</sup> *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).



1           The IHS Markit indices are prepared at the FERC functional subcategory level  
2           and are denoted with their corresponding FERC account number. The individual  
3           FERC account level indices are then combined into broader indices representing  
4           operation, maintenance, or total O&M expenses. The IHS Markit study used to  
5           prepare this filing was the fourth quarter 2021 forecast, released January 25, 2022.  
6           The IHS Markit data is proprietary and subject to copyright protection, therefore the  
7           indices utilized in the Company’s case are provided in Confidential Exhibit  
8           PAC/1005.

9           **Vegetation and Wildfire Management O&M (page 4.11)** – This adjustment  
10          removes wildfire mitigation and vegetation management expenses recorded in the  
11          Base Period, and then adds back in the expected levels of expense for the Test Period.  
12          As described above, please refer to the direct testimony of Mr. Berreth for a detailed  
13          discussion on the wildfire mitigation and vegetation management expenses in this  
14          case.

15          **Transmission Wheeling - Facebook (page 4.12)** – The Company executed a  
16          renewable resource contract in Utah (Docket 16-035-27) dedicated to serve load  
17          associated with Facebook. As a result of the increased load from this dedicated  
18          resource to serve Facebook, PacifiCorp will be allocated a higher ratio of wholesale  
19          transmission costs relative to other wholesale users of the Company’s transmission  
20          system. This adjustment reallocates the resulting incremental wheeling expense from  
21          non-Utah jurisdictions that should be situs-assigned to Utah.

1           **C.     Tab 5 – NPC Adjustments**

2           **Q.     Please describe the information contained behind Tab 5 NPC Adjustments.**

3           A.     Tab 5 includes adjustments to items that are generally related to NPC, most of which  
4                are addressed separately in the Company’s TAM filing. Specifically, adjustment page  
5                5.1, NPC Adjustment, relates solely to NPC and recovery of these costs is being  
6                sought in the TAM rather than the general rate case. This adjustment is included for  
7                modeling and computational purposes only. For example, the Test Period revenue  
8                requirement includes revenue sensitive items such as Franchise Tax, Resource  
9                Supplier Tax, and Public Utility Commission Fees that are calculated off total general  
10              business revenues, including those collected for the purpose of recovering costs  
11              included in the TAM.

12                     The NPC Index on page 5.0.1 is a brief overview of assumptions used to  
13                     adjust NPC-related items. The numerical summary (page 5.0.2) identifies each  
14                     adjustment made to actual expenses and that adjustment’s impact on overall revenue  
15                     requirement. Each column has a numerical reference to a corresponding page in the  
16                     Report, which contains a lead sheet showing the affected FERC account(s), allocation  
17                     factor(s), dollar amount, and a brief description of the adjustment.

18           **Q.     Please describe the adjustments included in Tab 5.**

19           A.     **NPC Adjustment (page 5.1)** – This adjustment normalizes power costs by adjusting  
20                sales for resale, purchased power, wheeling, and fuel in a manner consistent with the  
21                contractual terms of sales and purchase agreements, as well as normal hydro and  
22                temperature conditions for the Test Period. The Aurora study for this adjustment is  
23                based on forecasted loads for the Test Period. As previously described, this

1 adjustment is included in the calculation of overall revenue requirement for  
2 computational purposes only; NPC is not part of the revenue requirement for the  
3 general rate case.

4 **EIM BOSR and WRAP Fees (page 5.2)**—This adjustment adds into Test Period  
5 results Energy Imbalance Market (EIM) Body of State Regulators (BOSR) fee, and  
6 Western Resource Adequacy Program (WRAP) fee estimated for calendar year 2023.  
7 For further details, please refer to the direct testimony of Mr. Michael G. Wilding.

8 **D. Tab 6 – Depreciation and Amortization Expense Adjustments**

9 **Q. Please describe the information contained behind Tab 6 Depreciation and**  
10 **Amortization Adjustments.**

11 A. Tab 6 includes the Depreciation and Amortization Adjustment Index followed by a  
12 numerical summary and the specific adjustments. The Adjustment Index on page  
13 6.0.1 is a brief overview of assumptions used to adjust overall depreciation and  
14 amortization expense and reserve. The numerical summary (page 6.0.2) identifies  
15 each adjustment made to actual results and that adjustment’s impact on the case.  
16 Each column has a numerical reference to a corresponding page in the Report, which  
17 contains a lead sheet showing the affected FERC account(s), allocation factor(s),  
18 dollar amount, and a brief description of the adjustment.

19 **Q. Please describe the adjustments included in Tab 6.**

20 A. **Depreciation and Amortization Expense (page 6.1)** – This adjustment reflects the  
21 incremental depreciation expense associated with the capital additions included in  
22 Adjustment 8.4, Pro Forma Plant Additions, and calculates the depreciation expense  
23 using the approved depreciation rates in dockets UM 1968 and UE 374, which

1 became effective January 1, 2021. The annualized level of depreciation and  
2 amortization expense for the Test Period is calculated by applying the current  
3 composite depreciation and amortization rates to the December 2022 pro forma plant  
4 balances. Detailed calculation of the depreciation and amortization expense is  
5 provided on pages 6.1 through 6.1.13. The Company's proposal in this case to update  
6 certain coal-fired units' depreciable lives is not reflected in this adjustment, nor  
7 adjustment 6.2 below. This proposed change is reflected in adjustment 6.5 and  
8 discussed later in my testimony.

9 **Depreciation and Amortization Reserve (page 6.2)** – This adjustment steps forward  
10 the depreciation and amortization reserve from the Base Period to a December 2022  
11 adjusted level. Accumulated depreciation and amortization balances are calculated by  
12 applying pro forma depreciation and amortization expense and plant retirements to  
13 Base Period balances. The reserve balances are calculated on a monthly basis to walk  
14 the balances forward from June 30, 2021, to December 31, 2022. An incremental  
15 adjustment has been added to the December 31, 2022 balance to reflect the impact of  
16 annualized depreciation expense in adjustment 6.1. The reserve balance calculations  
17 are detailed on pages 6.2 to 6.2.11. As stated above, any depreciation and  
18 amortization reserve impacts as a result of the Company's proposed changes to coal-  
19 fired generating units' depreciable lives are reflected in its own adjustment later in  
20 Tab 6.

21 **Depreciation Allocation Correction Adjustment (page 6.3)** – The Company  
22 established a regulatory asset to track and defer any aggregate net increase in  
23 allocated depreciation expense in dockets in Wyoming, Utah, and Idaho, for

1 depreciation rates that became effective January 1, 2014. This deferred amount is  
2 reflected in historical data on a system-allocated basis, but should be situs-assigned to  
3 Wyoming, Utah, and Idaho. This adjustment removes the steam-related deferred  
4 depreciation expense from historical data for Oregon's results of operations. Also  
5 being removed in this adjustment is the steam plant give-back reversal in Oregon  
6 established as part of the 2012 Depreciation Study. This give-back amount does not  
7 need to be incrementally added back into results, since the Company's last rate case  
8 incorporated into rates updated depreciation rates consistent with the 2018  
9 Depreciation Study and reset annual depreciation expense to appropriate levels. The  
10 balance of give-back reversal being removed from the Base Period represents the  
11 amounts recorded in the last 6 months of 2020, prior to new depreciation rates  
12 becoming effective on January 1, 2021. Once new rates became effective on  
13 January 1, 2021, this give-back amount is no longer needed.

14 **Repowering Buy-Downs Adjustment (page 6.4)** – As a result of the all-party  
15 stipulation in docket UE 369, the undepreciated equipment balances from repowered  
16 assets were bought down in part with Excess Deferred Income Tax (EDIT) balances  
17 that resulted from the Tax Cut and Jobs Act (TCJA), and a portion of the Company's  
18 deferred FERC Open Access Transmission Tariff revenues. This adjustment corrects  
19 the allocation of expenses recorded in the Base Period as a result of the buy-downs  
20 for the Dunlap, and Foote Creek wind facilities. This adjustment also brings into  
21 results the amortization expense and accumulated reserves for wind facilities  
22 buy-downs for all repowered projects and adds into results pro forma amortization to  
23 reflect expense and reserves for these balances at the appropriate Test Year levels.

1       **Coal-fired Units Depreciable Life Update (page 6.5)** – In this proceeding, the  
2       Company is proposing to update the end of depreciable lives of Colstrip  
3       Units 3 and 4, Craig Unit 2, and Hayden Units 1 and 2. The Company’s proposal  
4       would result in an acceleration of Colstrip’s end of depreciable life to 2025.

5               Craig Unit 2’s end of depreciable life would be extended by one year and 9  
6       months, while Hayden Units 1 and 2 would see an extension of depreciable lives of  
7       5 and 4 years, respectively. This adjustment reflects the change in depreciation  
8       expense by imputing the incremental annual depreciation expense between accrual  
9       amounts based on current depreciation rates of the select coal-fired facilities, and the  
10      proposed accrual amounts that would result in these units’ respective net book value  
11      being fully depreciated for Oregon Customers by each unit’s retirement dates  
12      proposed in the Company’s 2021 IRP. Page 6.5.2 of Exhibit PAC/1002 provides a  
13      summary table of the change in end of depreciable life for each unit. Incremental  
14      reserves impact of the proposed change is reflected on an average basis.

15              The Company’s proposal to update depreciable lives results in a net decrease  
16      in depreciation expense of \$3.1 million on a total-company basis, which equates to  
17      approximately \$810,500 on an Oregon-allocated basis. Net of impacts on updating  
18      depreciation reserves and tax impacts, the Oregon-allocated revenue requirement of  
19      this proposed depreciable lives update is approximately (\$791,300). For details on  
20      the Company’s proposal to update depreciable lives on specific coal-fired units,  
21      please refer to the direct testimony of Ms. Steward.

22      **Bridger Coal Reclamation Costs (page 6.6)** – This adjustment reflects the recovery  
23      of accelerated depreciation and reclamation costs for the Bridger Mine incremental to

1 the amounts included in the cost of coal delivered to the Jim Bridger Plant approved  
2 in the Company's 2021 Rate Case. These costs are being recovered over the  
3 remaining depreciable life for Oregon customers of the Jim Bridger Plant. The  
4 adjustment in this case reflects the approved amounts of accelerated depreciation and  
5 reclamation costs for the Bridger Mine as approved in the 2021 Rate Case.

6 The above amounts being collected from Oregon customers are deferred to a  
7 regulatory liability, which will be debited with Oregon's share of reclamation costs  
8 when the Bridger Mine closes. This treatment allows the Company to recover the  
9 Bridger Mine while meeting the Senate Bill (SB) 1547 requirement of removing coal  
10 from Oregon electric utility rates prior to January 1, 2030.

11 **E. Tab 7 – Tax Adjustments**

12 **Q. Please describe the information contained behind Tab 7 Tax Adjustments.**

13 A. Tab 7 includes the Tax Adjustment Index followed by a numerical summary and the  
14 specific adjustments. The Adjustment Index (page 7.0.1) contains a brief overview of  
15 the tax adjustments included in this case. The numerical summary on pages 7.0.2 and  
16 7.0.3 identifies each adjustment made to the various tax components and that  
17 adjustment's impact on the case. Each column has a numerical reference to a  
18 corresponding page in the Report, which contains a lead sheet showing the affected  
19 FERC account(s), allocation factor(s), dollar amount, and a brief description of the  
20 adjustment.

21 **Q. Please describe the adjustments included in Tab 7.**

22 A. **Interest True-Up (page 7.1)** – This adjustment details the adjustment to interest  
23 expense required to synchronize the Test Period interest expense with Test Period rate

1 base. This is done by multiplying normalized net rate base by the Company's  
2 weighted cost of debt in this case.

3 **Property Tax Expense (page 7.2)** – Property tax expense for the Test Period is  
4 computed by adjusting accruals from the Base Period for known or anticipated  
5 changes in the assessed values of the Company's operating property and the  
6 corresponding effect such changes will have on property tax expense for the Test  
7 Period. For additional information on the Company's property tax estimation  
8 procedures and methodologies, please refer to Confidential Exhibit PAC/1003.

9 **Production Tax Credit (PTC) (page 7.3)** – The Company is entitled to recognize  
10 federal income tax credits as a result of placing renewable generating plants in  
11 service. The tax credit is based on the kilowatt-hours generated by the plants, and the  
12 credit can be taken for the first 10 years of generation from qualifying property. The  
13 PTC calculation reflects the credit based on the qualifying production as modeled for  
14 the Test Period NPC study. Customers receive the benefit of the PTCs in the  
15 Company's annual TAM filing. As with NPC in Adjustment 5.1, this adjustment is  
16 included for the purposes of calculating an overall revenue requirement only.

17 **PowerTax Accumulated Deferred Income Tax (ADIT) Balance (page 7.4)** This  
18 adjustment normalizes ADIT balances to an estimated pro forma level of rate base  
19 balance consistent with proforma capital additions, which are reflected through  
20 December 31, 2022. Additional line-item detail is included in the tax model that is  
21 provided with the Company's electronic workpapers.

22 **Pro Forma Tax Balances Adjustment (page 7.5)** – This adjustment normalizes the  
23 Schedule M items, deferred tax expense and related ADIT balances to an estimated



1 pro forma level of expense for the Test Period. Additional line-item detail is included  
2 in the tax model that is provided with the Company's electronic work papers.

3 **Wyoming Wind Generation Tax (page 7.6)** – This adjustment normalizes the  
4 Wyoming Wind Generation Tax, which became effective January 1, 2012, into Test  
5 Period results. The Wyoming Wind Generation Tax is an excise tax levied upon  
6 production of electricity from wind resources in the state of Wyoming. The tax is  
7 levied on the production of any electricity produced from wind resources for sale or  
8 trade on or after January 1, 2012 and is to be paid by the entity producing the  
9 electricity. New wind facilities are exempt from the tax for three years following the  
10 date the facility first produces electricity for sale. The tax is one dollar for each  
11 megawatt-hour (MWh) of electricity produced from wind resources at the point of  
12 interconnection with an electric transmission line.

13 **Allowance for Funds Used During Construction (AFUDC) Equity (page 7.7)** –  
14 This adjustment reflects the appropriate level of AFUDC equity into regulated results  
15 to align the tax schedule M with regulatory income. Per Commission Order 10-022,  
16 AFUDC equity in this case is included using  
17 flow-through tax treatment.<sup>19</sup>

18 **TCJA EDIT Adjustment (page 7.8)** – This adjustment adjusts the level of protected  
19 property EDIT amortization and adjusts the rate base for the test period consistent  
20 with pro forma capital additions, which are reflected through December 31, 2022.

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<sup>19</sup> *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).

1           **Oregon Corporate Activity Tax (OCAT) & Metro Business Income Tax (Metro**  
2           **BIT) Adjustment (page 7.9)** – This adjustment adds into base rates the forecasted  
3           OCAT and Metro BIT for the Test Period.

4           **F.       Tab 8 – Rate Base Adjustments**

5           **Q.       Please describe the information contained behind Tab 8 Rate Base Adjustments.**

6           A.       Tab 8 includes the Rate Base Adjustment Index followed by a numerical summary  
7           and the specific adjustments. The Adjustment Index on page 8.0.1 begins with a brief  
8           overview of assumptions used to adjust rate base components. The numerical  
9           summary (pages 8.0.2 to 8.0.4) identifies each adjustment made to actual rate base  
10          and that adjustment’s impact on the case. Each column has a numerical reference to a  
11          corresponding page in the Report, which contains a lead sheet showing the affected  
12          FERC account(s), allocation factor(s), dollar amount, and a brief description of the  
13          adjustment.

14          **Q.       Please describe each of the adjustments to the historical rate base balances.**

15          A.       **Cash Working Capital (page 8.1)** – This adjustment supports the calculation of cash  
16          working capital included in rate base based on the normalized results of operations  
17          for the Test Period. Total cash working capital is calculated by multiplying  
18          jurisdictional net lag days by the average daily cost of service. Net lag days in this  
19          case are based on a lead lag study prepared by PacifiCorp using calendar year 2015  
20          information. An electronic version of the lead lag study is included as part of the  
21          Company’s workpapers.

22          **Trapper Mine Rate Base (page 8.2)** – The Company owns a 29.14 percent interest  
23          in the Trapper Mine, which provides coal to the Craig generating plant. The

1 normalized coal cost of Trapper includes all O&M costs but does not include a return  
2 on investment. This adjustment adds the Company's portion of the Trapper Mine  
3 plant investment to the rate base and reflects net plant to recognize the depreciation of  
4 the investment over time. This adjustment also walks the reclamation liability  
5 forward to December 2022. This adjustment was stipulated to and approved in  
6 docket UE 111<sup>20</sup> and has been included in all Oregon rate case filings since.

7 **Jim Bridger Mine Rate Base (page 8.3)** – The Company owns a two-thirds interest  
8 in the Bridger Coal Company, which supplies coal to the Jim Bridger generating  
9 plant. The Company's investment in Bridger Coal Company is recorded on the books  
10 of Pacific Minerals, Inc. Because of this ownership arrangement, the coal mine  
11 investment is not included in electric plant in service. This adjustment is necessary to  
12 properly reflect the Bridger Coal Company investment in rate base for the Company  
13 to earn a return on its investment. The normalized coal costs for Bridger Coal  
14 Company in NPC include the O&M costs of the mine but provide no return on  
15 investment. This adjustment adds the Company's portion of the pro forma  
16 December 31, 2022 net plant balance to rate base. This adjustment was stipulated to  
17 and approved in docket UE 111 and has been included in all Oregon rate case filings  
18 since.<sup>21</sup>

19 **Pro Forma Plant Additions and Retirements (page 8.4)** – To reasonably represent  
20 the cost of system infrastructure required to serve customers, the Company has  
21 identified capital projects that will be used and useful by December 31, 2022.

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<sup>20</sup> *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).

<sup>21</sup> *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).

1 Capital additions by FERC functional category are listed on pages 8.4.19 to 8.4.26,  
2 indicating the in-service date and amount by project. This adjustment is based on  
3 plant balances as of December 31, 2022. As described earlier in my testimony, the  
4 accumulated depreciation reserve was adjusted forward to match the depreciation  
5 expense and retirements. Projects over \$10 million (total-company basis) are  
6 described on pages 8.4.28 through 8.4.32 of the Report. Pro forma capital additions  
7 do not reflect any projects for wildfire restoration related to the Labor Day wildfires.

8 **Customer Advances for Construction (page 8.5)** – Customer advances were  
9 recorded in the Base Period to a corporate cost center location rather than state-  
10 specific locations. This adjustment corrects the allocation factors of customer  
11 advances.

12 **Regulatory Asset and Liability Amortization (page 8.6)** – This adjustment  
13 normalizes regulatory assets and liabilities from the Base Period to the Test Period.  
14 In addition, the Company is proposing to begin amortization of deferred  
15 Transportation Electrification Program (TEP) expenses from 2018 through 2021.<sup>22</sup>  
16 TEP expenses incurred after 2021 will be recovered through the System Benefits  
17 Charge.<sup>23</sup> The Company is proposing an amortization period of three years.

18 In this adjustment, the Company is also proposing to begin amortization of the  
19 deferred 2021 and 2022 REC revenues from the sale of Pryor Mountain RECs  
20 through Schedule 272 over a three-year amortization period. Additionally, since these

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<sup>22</sup> *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program*, Docket No. UM 1964, Application (Jul. 27, 2018).

<sup>23</sup> *In the matter of PacifiCorp dba Pacific Power 2020 Renewable Adjustment Clause*, Docket No. 369, Stipulation and Joint Testimony (Jan. 31, 2020).

1 specific REC revenues are forecasted to be fairly stable, the Company is proposing  
2 including into base rates effective January 1, 2023, an annual level of forecasted REC  
3 revenues for these sales into base rates.

4 **Plant Held for Future Use (PHFU) (page 8.7)** – This adjustment removes all PHFU  
5 assets from FERC account 105. The Company is making this adjustment in  
6 compliance with Order 01-787.<sup>24</sup>

7 **Pension and Other Post-retirement Plan Balances Removal (page 8.8)** – This  
8 adjustment removes the Company’s net prepaid asset associated with its pension and  
9 other post-retirement welfare plans, net of associated accumulated deferred income  
10 taxes in unadjusted results. Per Order 15-226 in docket UM 1633, the net pension  
11 and post-retirement prepaid is not to be included in rate base for Oregon.<sup>25</sup>

12 **Remove Rolling Hills (page 8.9)** – This adjustment removes the gross plant,  
13 accumulated depreciation, and O&M amounts related to the Rolling Hills wind  
14 resource from the Base Period. Depreciation expense for Rolling Hills is removed in  
15 Adjustment 6.1, Depreciation/Amortization Expense Adjustment. This treatment is  
16 consistent with Order 08-548.<sup>26</sup>

17 **Deer Creek Mine Adjustment (page 8.10)** – Order 15-161 in docket UM 1712  
18 addressed closure of the Deer Creek mine located in Utah and ruled on several

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<sup>24</sup> *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)

<sup>25</sup> *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).

<sup>26</sup> *In the matter 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).

1 issues.<sup>27</sup> Order 20-473 in the Company's 2021 Rate Case approved for recovery of  
2 the Company's deferred unrecovered plant balances and associated closure costs in a  
3 separate tariff to be amortized over three years. The same order also determined that  
4 coal lease abandonment royalty costs were to be excluded from amounts being  
5 amortized on the basis that amounts were considered preliminary, and the timing of  
6 payment was not yet certain. The Company is, however, allowed to continue to defer  
7 these costs as approved in UM 1712, and may seek recovery in a future rate  
8 proceeding.<sup>28</sup> At the time this rate case was prepared, this royalty obligation remains  
9 outstanding. As such, the Company has not included that amount in this proceeding  
10 and will continue to defer this amount until amounts and payment timing can be  
11 accurately determined.

12 This adjustment removes all Deer Creek regulatory assets and closure costs  
13 from Base Period results, as these amounts are being recovered through a separate  
14 tariff rider, with interest at the modified blended Treasury rate. In addition, this  
15 adjustment adds into base rates the annual payment resulting from the Company's  
16 withdrawal from the 1974 Pension Trust associated with Deer Creek Mine. This  
17 amount was previously included in the TAM but was approved to be removed from  
18 the TAM to be included in base rates instead in Order 20-473.

19 **Emissions Control Investment Adjustment (page 8.11)** – This adjustment reflects  
20 in results rate base and return disallowances on emissions control investments as  
21 ordered in Order 20-473 in docket UE 374. This adjustment was prepared in the

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<sup>27</sup> *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).*

<sup>28</sup> Order No. 20-473 at 88.

1 same manner as was included in the Company’s compliance filing in the 2021 Rate  
2 Case.

3 **Transmission Project Adjustment (page 8.12)** – This adjustment reflects in results  
4 project cost disallowances on specific transmission projects as ordered in Order 20-  
5 473 in docket UE 374.

6 **Cholla Unit 4 Retirement (page 8.13)** – This adjustment removes from rate base  
7 balances related to Cholla Unit 4, which was retired on December 31, 2020. It also  
8 removes costs related to the O&M of this generation resource. These amounts are in  
9 Base Period results because the Company’s base period in this case spans from July  
10 2020 to June 2021—six months of which Cholla Unit 4 was still operational.

11 In the 2021 Rate Case, the Company’s proposal to buy down the  
12 undepreciated plant balance and closure costs using TCJA deferred tax benefits was  
13 approved. Consequently, the revenue requirement calculation in this rate case also  
14 excludes all the regulatory assets associated with costs that have previously been  
15 approved to be bought down.

16 In this case, the Company is requesting recovery of additional closure cost  
17 items associated with the Cholla Unit 4 closure for which amounts were unknown and  
18 were not included in the previous case. Included in this case for recovery is deferred  
19 safe harbor lease termination payment and non-union severance expense.

20 Additionally, as authorized in Order 20-473 the assessed property tax costs assigned  
21 to Cholla Unit 4 through the closure process have been deferred and are eligible for  
22 amortization, with interest to accumulate at the modified blended Treasury rate. This  
23 adjustment reflects the annual amortization expense associated with the incremental

1 closure costs with a corresponding adjustment to the regulatory asset balance to  
2 reflect the 13-month average balance in the Test Period. As for deferred property tax  
3 costs, an annual amortization amount has also been calculated, but consistent with the  
4 ordered treatment in Order 20-473, the balance accrues interest at the modified  
5 blended Treasury rate and is removed from rate base.

6 **Wind Project Deferrals Amortization (page 8.14)** – This adjustment adds into Test  
7 Period results the amortization of deferred revenue requirement associated with Cedar  
8 Springs II wind project, which went into service in December 2020, one month prior  
9 to new rates from the 2021 Rate Case becoming effective. Cedar Springs II was part  
10 of Energy Vision 2020 wind projects determined to be prudent in the 2021 Rate Case  
11 (Order 20-473). The Company has a pending application for deferral treatment  
12 (docket UM 2134) of the revenue requirement for Cedar Springs II in front of the  
13 Commission, for the approximately one-month period that the facility was in service  
14 and serving customers, but its costs were not yet reflected in customer rates. The  
15 2020 benefits of Cedar Springs II were included in rates for the 2020 TAM.

16 This adjustment also adds into Test Period results the amortization of deferred  
17 revenue requirement, net of 2021 NPC and PTC benefits, associated with TB Flats.<sup>29</sup>  
18 TB Flats was also part of the Energy Vision 2020 wind projects determined to be  
19 prudent in the 2021 Rate Case. The revenue requirement deferral for which the  
20 Company is seeking approval to begin amortization for is exclusively based on the  
21 incremental project costs that are not yet part of customer rates.

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<sup>29</sup> 2022 NPC and PTC benefits for TB Flats are included in rates through the 2022 TAM.



1 For both deferred balances, the Company is proposing a three-year  
2 amortization period, starting January 1, 2023, to collect the deferred net revenue  
3 requirement associated with these wind projects not having been or being recovered  
4 in customer rates. Monthly amounts continue to accrue on these deferred balances  
5 through December 2022. Upon January 1, 2023, when new rates from the current  
6 case becomes effective, these deferrals will no longer be accruing additional amounts,  
7 as the full revenue requirement would be in base rates at that time.

8 **Miscellaneous Rate Base (page 8.15)** – This adjustment reflects the change in the  
9 fuel stock balance from the Base Period to the Test Period. This adjustment also  
10 reflects the working capital deposits that are offsets to fuel stock costs. In addition,  
11 balances for prepaid overhauls at the Lake Side, Chehalis, and Currant Creek natural  
12 gas plants are walked forward to reflect payments and transfers of capital to electric  
13 plant in service on a 13-month average basis through the Test Period. This  
14 adjustment was included in the stipulated settlement and approved in the Company’s  
15 2013 Rate Case, and have been included in every rate case since.<sup>30</sup>

16 **Carbon Plant Retirement (page 8.16)** – The Company established a regulatory asset  
17 to track and defer any aggregate net increase in allocated depreciation expense in  
18 dockets in Wyoming, Utah, and Idaho for depreciation rates that became effective  
19 January 1, 2014. This deferred amount includes a portion representing the  
20 accelerated depreciation expense associated with the early retirement of the Carbon  
21 plant. The Carbon plant was retired in April 2015. The deferral and amortization  
22 continued to be recorded in the Company’s accounting books in the Base Period.

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<sup>30</sup> Order No. 13-474 at 3 and App. A at 18.

1           However, this deferred expense is being recorded on a system-allocated basis, when it  
2           should be situs-assigned to Utah, Idaho, and Wyoming only. This adjustment  
3           removes the system-allocated amount from Oregon’s historical results of operations.  
4           In the 2021 Rate Case, amortization of Oregon’s excess decommissioning reserve, net  
5           of Oregon’s allocation of Carbon’s obsolete materials and supplies inventory, over  
6           five years was approved. This adjustment also reflects in results the amortization and  
7           forecasted balances for the Test Period.

8           **Remove Labor Day Wildfire Restoration (page 8.17)** – This adjustment removes  
9           from rate base the historical capital additions placed in-service as part of Labor Day  
10          Wildfire restoration efforts. This adjustment also removes the associated depreciation  
11          reserves from the Base Period. The Company is excluding capital projects related to  
12          the Labor Day wildfire events from this rate case at this time. The Company may  
13          seek recovery of these projects in a future proceeding.

14          **G.     Tab 9 – 2020 Protocol ECD**

15          **Q.     Please describe the information contained behind Tab 9.**

16          A.     Tab 9 demonstrates the derivation of the 2020 Protocol ECD amount included in the  
17          current rate case.

18          **Q.     Please describe the ECD adjustment under 2020 Protocol.**

19          A.     Under 2020 Protocol, the Fixed ECD, as used in the 2017 Protocol, will continue for  
20          Idaho at \$836,000 through the end of 2023. The Dynamic ECD, as used in the  
21          2010 Protocol, will continue for Oregon through the end of 2023, capped at  
22          \$11,000,000. No ECD adjustment exists for Utah or California. In Wyoming, the  
23          ECD terminated as of December 31, 2020.

1 **Q. What is the Dynamic ECD?**

2 A. The Dynamic ECD measures the embedded cost differentials between the production  
3 costs of pre-2005 resources, as defined in the 2010 Protocol, and the production cost  
4 of west hydro-electric resources and certain Mid-Columbia Contracts. The first part  
5 is computed by taking PacifiCorp's production costs related to pre-2005 resources,  
6 expressed in dollars per MWh, compared to production costs of west-side hydro-  
7 electric resources expressed in dollars per MWh with the difference multiplied by the  
8 hydro-electric resources' MWhs of production. The second part is computed by  
9 taking the differential between the pre-2005 resources' dollars per MWh compared to  
10 Mid-Columbia Contracts' costs on a dollars per MWh multiplied by the Mid-  
11 Columbia Contracts' MWhs.

12 **H. Tab 10 – Allocation Factors**

13 **Q. Please describe the information contained behind Tab 10 Allocation Factors.**

14 A. Tab 10 Allocation Factors summarizes the derivation of the inter-jurisdictional  
15 allocation factors using the 2020 Protocol.

16 **I. Tabs B1 to B20**

17 **Q. Please describe the information contained behind Tabs B1 to B20.**

18 A. Tabs B1 through B20 contain the historical results for the Base Period and are  
19 organized by major FERC function. The data contained in this section of the Report  
20 matches the unadjusted data found under Tab 2 – Results of Operations.

1

**VI. CONCLUSION**

2 **Q. Please summarize your testimony.**

3 A. I recommend that the Commission approve the requested \$84.4 million increase and  
4 non-NPC revenue requirement of \$1,044.8 million.

5 **Q. Does this conclude your direct testimony?**

6 A. Yes.

Docket No. UE 399  
Exhibit PAC/1001  
Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Sherona L. Cheung  
Revenue Requirement Summary**

**March 2022**

**PacifiCorp  
OREGON**

PAGE 1.0

**Normalized Results of Operations - 2020 PROTOCOL  
Twelve Months Ending December 31, 2023**

	(1)	(2)	(3)	(4)	(5)	(6)
		(3) - (1)	Ref. Page 1.3			(3) + (4) + (5)
				<b>TAM</b>	<b>GRC</b>	
	NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Under Recovery	Requested Non-NPC Related Price Change	Total Normalized Results with Price Change
1 Operating Revenues:						
2 General Business Revenues	288,535,772	960,365,378	1,248,901,150	69,973,978	84,399,290	1,403,274,418
3 Interdepartmental		-	-			-
4 Special Sales	92,708,477	-	92,708,477			92,708,477
5 Other Operating Revenues		81,179,990	81,179,990			81,179,990
6 Total Operating Revenues	<u>381,244,249</u>	<u>1,041,545,368</u>	<u>1,422,789,617</u>	<u>69,973,978</u>	<u>84,399,290</u>	<u>1,577,162,885</u>
7						
8 Operating Expenses:						
9 Steam Production	154,813,423	83,222,619	238,036,042			238,036,042
10 Nuclear Production		-	-			-
11 Hydro Production		12,077,585	12,077,585			12,077,585
12 Other Power Supply	324,792,931	18,843,638	343,636,569			343,636,569
13 Transmission	41,801,335	18,785,840	60,587,175			60,587,175
14 Distribution		116,940,088	116,940,088			116,940,088
15 Customer Accounting		23,492,890	23,492,890		771,495	24,264,385
16 Customer Service & Info		6,029,376	6,029,376			6,029,376
17 Sales		-	-			-
18 Administrative & General		60,742,837	60,742,837			60,742,837
19						
20 Total O&M Expenses	<u>521,407,688</u>	<u>340,134,873</u>	<u>861,542,561</u>	<u>-</u>	<u>771,495</u>	<u>862,314,056</u>
21						
22 Depreciation		287,994,295	287,994,295			287,994,295
23 Amortization		43,237,301	43,237,301			43,237,301
24 Taxes Other Than Income		84,171,808	84,171,808		4,288,376	88,460,183
25 Income Taxes - Federal	(81,030,263)	19,734,117	(61,296,146)	14,027,403	15,904,856	(31,363,887)
26 Income Taxes - State	(6,363,420)	10,593,846	4,230,426	3,176,819	3,602,010	11,009,254
27 Income Taxes - Def Net		12,660,019	12,660,019			12,660,019
28 Investment Tax Credit Adj.		-	-			-
29 Misc Revenue & Expense		3,165	3,165			3,165
30						
31 Total Operating Expenses:	<u>434,014,005</u>	<u>798,529,424</u>	<u>1,232,543,429</u>	<u>17,204,222</u>	<u>24,566,737</u>	<u>1,274,314,388</u>
32						
33 Operating Rev For Return:	<u>(52,769,756)</u>	<u>243,015,944</u>	<u>190,246,188</u>	<u>52,769,756</u>	<u>59,832,554</u>	<u>302,848,497</u>
34						
35 Rate Base:						
36 Electric Plant In Service		8,852,783,093	8,852,783,093			8,852,783,093
37 Plant Held for Future Use		-	-			-
38 Misc Deferred Debits		67,300,330	67,300,330			67,300,330
39 Elec Plant Acq Adj		701,604	701,604			701,604
40 Pension		-	-			-
41 Prepayments		11,129,917	11,129,917			11,129,917
42 Fuel Stock		43,192,126	43,192,126			43,192,126
43 Material & Supplies		81,719,811	81,719,811			81,719,811
44 Working Capital		13,347,565	13,347,565			13,347,565
45 Weatherization Loans		-	-			-
46 Misc Rate Base		-	-			-
47						
48 Total Electric Plant:	<u>-</u>	<u>9,070,174,446</u>	<u>9,070,174,446</u>			<u>9,070,174,446</u>
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec		(3,571,364,011)	(3,571,364,011)			(3,571,364,011)
52 Accum Prov For Amort		(218,109,109)	(218,109,109)			(218,109,109)
53 Accum Def Income Tax		(643,480,187)	(643,480,187)			(643,480,187)
54 Unamortized ITC		(45,778)	(45,778)			(45,778)
55 Customer Adv For Const		(23,030,533)	(23,030,533)			(23,030,533)
56 Customer Service Deposits		-	-			-
57 Misc Rate Base Deductions		(415,023,294)	(415,023,294)			(415,023,294)
58						
59 Total Rate Base Deductions	<u>-</u>	<u>(4,871,052,912)</u>	<u>(4,871,052,912)</u>			<u>(4,871,052,912)</u>
60						
61 Total Rate Base:	<u>-</u>	<u>4,199,121,534</u>	<u>4,199,121,534</u>			<u>4,199,121,534</u>
62						
63 Return on Rate Base			4.531%			7.212%
64						
65 Return on Equity			4.668%			9.800%

**PacifiCorp**  
**OREGON**  
**Normalized Results of Operations - 2020 PROTOCOL**  
**Twelve Months Ending December 31, 2023**

**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	960,365,378	84,399,290	1,044,764,668
3 Interdepartmental	-		-
4 Special Sales	-		-
5 Other Operating Revenues	81,179,990		81,179,990
6 Total Operating Revenues	<u>1,041,545,368</u>	<u>84,399,290</u>	<u>1,125,944,658</u>
7			
8 Operating Expenses:			
9 Steam Production	83,222,619		83,222,619
10 Nuclear Production	-		-
11 Hydro Production	12,077,585		12,077,585
12 Other Power Supply	18,843,638		18,843,638
13 Transmission	18,785,840		18,785,840
14 Distribution	116,940,088		116,940,088
15 Customer Accounting	23,492,890	771,495	24,264,385
16 Customer Service & Info	6,029,376		6,029,376
17 Sales	-		-
18 Administrative & General	60,742,837		60,742,837
19			
20 Total O&M Expenses	340,134,873	771,495	340,906,368
21			
22 Depreciation	287,994,295		287,994,295
23 Amortization	43,237,301		43,237,301
24 Taxes Other Than Income	84,171,808	4,288,376	88,460,183
25 Income Taxes - Federal	19,734,117	15,904,856	35,638,973
26 Income Taxes - State	10,593,846	3,602,010	14,195,856
27 Income Taxes - Def Net	12,660,019		12,660,019
28 Investment Tax Credit Adj.	-		-
29 Misc Revenue & Expense	3,165		3,165
30			
31 Total Operating Expenses:	798,529,424	24,566,737	823,096,161
32			
33 Operating Rev For Return:	<u>243,015,944</u>	<u>59,832,554</u>	<u>302,848,497</u>
34			
35 Rate Base:			
36 Electric Plant In Service	8,852,783,093		8,852,783,093
37 Plant Held for Future Use	-		-
38 Misc Deferred Debits	67,300,330		67,300,330
39 Elec Plant Acq Adj	701,604		701,604
40 Pension	-		-
41 Prepayments	11,129,917		11,129,917
42 Fuel Stock	43,192,126		43,192,126
43 Material & Supplies	81,719,811		81,719,811
44 Working Capital	13,347,565		13,347,565
45 Weatherization Loans	-		-
46 Misc Rate Base	-		-
47			
48 Total Electric Plant:	9,070,174,446		9,070,174,446
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	(3,571,364,011)		(3,571,364,011)
52 Accum Prov For Amort	(218,109,109)		(218,109,109)
53 Accum Def Income Tax	(643,480,187)		(643,480,187)
54 Unamortized ITC	(45,778)		(45,778)
55 Customer Adv For Const	(23,030,533)		(23,030,533)
56 Customer Service Deposits	-		-
57 Misc Rate Base Deductions	(415,023,294)		(415,023,294)
58			
59 Total Rate Base Deductions	(4,871,052,912)		(4,871,052,912)
60			
61 Total Rate Base:	<u>4,199,121,534</u>		<u>4,199,121,534</u>
62			
63 Return on Rate Base	5.787%		7.212%
64			
65 Return on Equity	7.073%		9.800%
66			
67 TAX CALCULATION:			
68 Operating Revenue	286,003,926	79,339,420	365,343,345
69 Other Deductions			
70 Interest (AFUDC)	(21,356,078)	-	(21,356,078)
71 Interest	84,048,729	-	84,048,729
72 Schedule "M" Additions	333,382,419	-	333,382,419
73 Schedule "M" Deductions	452,107,568	-	452,107,568
74 Income Before Tax	104,586,126	79,339,420	183,925,546
75			
76 State Income Taxes	10,593,846	3,602,010	14,195,856
77 Taxable Income	<u>93,992,280</u>	<u>75,737,410</u>	<u>169,729,690</u>
78			
79 Federal Income Taxes + Other	<u>19,734,117</u>	<u>15,904,856</u>	<u>35,638,973</u>

**PacifiCorp  
OREGON**

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**Normalized Results of Operations - 2020 PROTOCOL  
Twelve Months Ending December 31, 2023**

**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	288,535,772	69,973,978	358,509,750
3 Interdepartmental	-	-	-
4 Special Sales	92,708,477	-	92,708,477
5 Other Operating Revenues	-	-	-
6 Total Operating Revenues	<u>381,244,249</u>	<u>69,973,978</u>	<u>451,218,227</u>
7			
8 Operating Expenses:			
9 Steam Production	154,813,423	-	154,813,423
10 Nuclear Production	-	-	-
11 Hydro Production	-	-	-
12 Other Power Supply	324,792,931	-	324,792,931
13 Transmission	41,801,335	-	41,801,335
14 Distribution	-	-	-
15 Customer Accounting	-	-	-
16 Customer Service & Info	-	-	-
17 Sales	-	-	-
18 Administrative & General	-	-	-
19			
20 Total O&M Expenses	<u>521,407,688</u>	<u>-</u>	<u>521,407,688</u>
21			
22 Depreciation	-	-	-
23 Amortization	-	-	-
24 Taxes Other Than Income	-	-	-
25 Income Taxes - Federal	(81,030,263)	14,027,403	(67,002,860)
26 Income Taxes - State	(6,363,420)	3,176,819	(3,186,602)
27 Income Taxes - Def Net	-	-	-
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	-
30			
31 Total Operating Expenses:	<u>434,014,005</u>	<u>17,204,222</u>	<u>451,218,227</u>
32			
33 Operating Rev For Return:	<u>(52,769,756)</u>	<u>52,769,756</u>	<u>-</u>
34			
35 Rate Base:			
36 Electric Plant In Service	-	-	-
37 Plant Held for Future Use	-	-	-
38 Misc Deferred Debits	-	-	-
39 Elec Plant Acq Adj	-	-	-
40 Pension	-	-	-
41 Prepayments	-	-	-
42 Fuel Stock	-	-	-
43 Material & Supplies	-	-	-
44 Working Capital	-	-	-
45 Weatherization Loans	-	-	-
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	<u>-</u>	<u>-</u>	<u>-</u>
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	-	-	-
52 Accum Prov For Amort	-	-	-
53 Accum Def Income Tax	-	-	-
54 Unamortized ITC	-	-	-
55 Customer Adv For Const	-	-	-
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	-	-	-
58			
59 Total Rate Base Deductions	<u>-</u>	<u>-</u>	<u>-</u>
60			
61 Total Rate Base:	<u>-</u>	<u>-</u>	<u>-</u>
62			
63 Return on Rate Base	N/A		N/A
64			
65 Return on Equity	N/A		N/A
66			
67 TAX CALCULATION:			
68 Operating Revenue	(140,163,439)	69,973,978	(70,189,462)
69 Other Deductions	-	-	-
70 Interest (AFUDC)	-	-	-
71 Interest	-	-	-
72 Schedule "M" Additions	-	-	-
73 Schedule "M" Deductions	-	-	-
74 Income Before Tax	<u>(140,163,439)</u>	<u>69,973,978</u>	<u>(70,189,462)</u>
75			
76 State Income Taxes	<u>(6,363,420)</u>	<u>3,176,819</u>	<u>(3,186,602)</u>
77 Taxable Income	<u>(133,800,019)</u>	<u>66,797,159</u>	<u>(67,002,860)</u>
78			
79 Federal Income Taxes + Other	<u>(81,030,263)</u>	<u>14,027,403</u>	<u>(67,002,860)</u>



**PacifiCorp**  
**OREGON**  
**Normalized Results of Operations - 2020 PROTOCOL**  
**Twelve Months Ending December 31, 2023**

	(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1 Operating Revenues:			
2 General Business Revenues	1,248,901,150	154,373,268	1,403,274,418
3 Interdepartmental	-		
4 Special Sales	92,708,477		
5 Other Operating Revenues	81,179,990		
6 Total Operating Revenues	<u>1,422,789,617</u>		
7			
8 Operating Expenses:			
9 Steam Production	238,036,042		
10 Nuclear Production	-		
11 Hydro Production	12,077,585		
12 Other Power Supply	343,636,569		
13 Transmission	60,587,175		
14 Distribution	116,940,088		
15 Customer Accounting	23,492,890	771,495	24,264,385
16 Customer Service & Info	6,029,376		
17 Sales	-		
18 Administrative & General	60,742,837		
19			
20 Total O&M Expenses	861,542,561		
21			
22 Depreciation	287,994,295		
23 Amortization	43,237,301		
24 Taxes Other Than Income	84,171,808	4,288,376	88,460,183
25 Income Taxes - Federal	(61,296,146)	29,932,259	(31,363,887)
26 Income Taxes - State	4,230,426	6,778,828	11,009,254
27 Income Taxes - Def Net	12,660,019		
28 Investment Tax Credit Adj.	-		
29 Misc Revenue & Expense	3,165		
30			
31 Total Operating Expenses:	1,232,543,429	41,770,958	1,274,314,388
32			
33 Operating Rev For Return:	<u>190,246,188</u>	<u>112,602,309</u>	<u>302,848,497</u>
34			
35 Rate Base:			
36 Electric Plant In Service	8,852,783,093		
37 Plant Held for Future Use	-		
38 Misc Deferred Debits	67,300,330		
39 Elec Plant Acq Adj	701,604		
40 Pensions	-		
41 Prepayments	11,129,917		
42 Fuel Stock	43,192,126		
43 Material & Supplies	81,719,811		
44 Working Capital	13,347,565		
45 Weatherization Loans	-		
46 Misc Rate Base	-		
47			
48 Total Electric Plant:	9,070,174,446	-	9,070,174,446
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	(3,571,364,011)		
52 Accum Prov For Amort	(218,109,109)		
53 Accum Def Income Tax	(643,480,187)		
54 Unamortized ITC	(45,778)		
55 Customer Adv For Const	(23,030,533)		
56 Customer Service Deposits	-		
57 Misc Rate Base Deductions	(415,023,294)		
58			
59 Total Rate Base Deductions	(4,871,052,912)	-	(4,871,052,912)
60			
61 Total Rate Base:	<u>4,199,121,534</u>	<u>-</u>	<u>4,199,121,534</u>
62			
63 Return on Rate Base	4.531%		7.212%
64			
65 Return on Equity	4.668%		9.800%
66			
67 TAX CALCULATION:			
68 Operating Revenue	145,840,487	149,313,397	295,153,884
69 Other Deductions			
70 Interest (AFUDC)	(21,356,078)	-	(21,356,078)
71 Interest	84,048,729	-	84,048,729
72 Schedule "M" Additions	333,382,419	-	333,382,419
73 Schedule "M" Deductions	452,107,568	-	452,107,568
74 Income Before Tax	<u>(35,577,313)</u>	<u>149,313,397</u>	<u>113,736,084</u>
75			
76 State Income Taxes	4,230,426	6,778,828	11,009,254
77 Taxable Income	<u>(39,807,739)</u>	<u>142,534,569</u>	<u>102,726,830</u>
78			
79 Federal Income Taxes + Other	<u>(61,296,146)</u>	<u>29,932,259</u>	<u>(31,363,887)</u>

**Pacificorp**  
**Oregon General Rate Case**  
**Adjustment Summary**  
**Twelve Months Ending December 31, 2023**

	Exhibit PAC/1002		Exhibit PAC/1002			
	TOTAL COMPANY UNADJUSTED RESULTS JUNE 2021	OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2021	Tab 3 Revenue Adjustments	Tab 4 O&M Adjustments	Tab 5 Net Power Cost Adjustments	Tab 6 Depreciation & Amortization Adjustments
1 Operating Revenues:						
2 General Business Revenues	5,081,632,249	1,308,339,123	(61,204,592)	1,766,619	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	212,315,668	52,145,322	-	-	40,563,155	-
5 Other Operating Revenues	227,962,549	74,239,841	4,704,600	-	-	-
6 Total Operating Revenues	5,521,910,467	1,434,724,286	(56,499,992)	1,766,619	40,563,155	-
7						
8 Operating Expenses:						
9 Steam Production	997,145,306	256,305,884	-	5,165,696	(14,027,757)	3,634,603
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	76,270,911	19,884,087	-	(7,806,503)	-	-
12 Other Power Supply	1,076,832,156	266,678,359	-	2,779,918	74,475,770	-
13 Transmission	220,828,048	57,410,559	-	155,610	3,021,006	-
14 Distribution	227,788,851	88,583,363	-	28,356,724	-	-
15 Customer Accounting	70,180,739	22,022,443	-	1,470,447	-	-
16 Customer Service & Info	116,029,408	5,610,498	-	418,878	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	296,924,361	86,907,150	-	(25,183,567)	-	-
19						
20 Total O&M Expenses	3,081,999,779	803,402,344	-	5,357,203	63,469,020	3,634,603
21						
22 Depreciation	1,035,081,277	232,580,644	-	-	-	58,506,685
23 Amortization	61,823,778	16,306,178	-	-	-	24,557,686
24 Taxes Other Than Income	212,196,714	79,098,063	-	(1,473,948)	-	-
25 Income Taxes - Federal	(28,741,917)	8,249,843	(11,325,777)	1,450,480	(4,594,138)	(13,912,304)
26 Income Taxes - State	26,781,277	9,304,835	(2,564,975)	328,494	(1,040,445)	(3,150,752)
27 Income Taxes - Def Net	(64,900,993)	(21,612,618)	-	(2,473,765)	-	(259,669)
28 Investment Tax Credit Adj.	(1,703,368)	-	-	-	-	-
29 Misc Revenue & Expense	(1,733,836)	(99,173)	-	102,338	-	-
30						
31 Total Operating Expenses:	4,320,802,712	1,127,230,117	(13,890,752)	3,290,802	57,834,436	69,376,249
32						
33 Operating Rev For Return:	1,201,107,755	307,494,169	(42,609,240)	(1,524,183)	(17,271,281)	(69,376,249)
34						
35 Rate Base:						
36 Electric Plant In Service	31,317,729,025	8,567,379,441	-	-	-	-
37 Plant Held for Future Use	23,896,248	9,657,872	-	-	-	-
38 Misc Deferred Debits	962,744,647	193,776,856	-	-	-	-
39 Elec Plant Acq Adj	14,875,820	1,753,028	-	-	-	-
40 Pensions	28,656,862	7,786,953	-	-	-	-
41 Prepayments	67,554,352	11,129,917	-	-	-	-
42 Fuel Stock	201,471,836	50,505,232	-	-	-	-
43 Material & Supplies	273,026,865	83,112,462	-	-	-	-
44 Working Capital	46,340,902	13,995,191	(131,295)	53,519	546,651	(126,926)
45 Weatherization Loans	199,224,237	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	33,135,520,794	8,939,096,950	(131,295)	53,519	546,651	(126,926)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(9,626,761,743)	(2,815,387,372)	-	-	-	(752,230,479)
52 Accum Prov For Amort	(691,673,798)	(201,534,614)	-	-	-	(16,574,495)
53 Accum Def Income Tax	(2,565,819,019)	(623,521,952)	-	(9,430,521)	-	(602,563)
54 Unamortized ITC	(2,245,487)	(50,351)	-	-	-	-
55 Customer Adv For Const	(104,109,027)	(28,119,926)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(2,269,895,491)	(489,871,272)	-	38,356,344	-	(7,266,788)
58						
59 Total Rate Base Deductions	(15,260,504,564)	(4,158,485,487)	-	28,925,824	-	(776,674,325)
60						
61 Total Rate Base:	17,875,016,231	4,780,611,463	(131,295)	28,979,343	546,651	(776,801,251)
62						
63 Return on Rate Base		6.432%	-0.891%	-0.065%	-0.360%	-0.735%
64						
65 Return on Equity		8.307%	-1.706%	-0.125%	-0.688%	-1.406%
66						
67 TAX CALCULATION:						
68 Operating Revenue		303,436,230	(56,499,992)	(2,218,974)	(22,905,864)	(86,698,974)
69 Other Deductions						
70 Interest (AFUDC)		(20,265,333)	-	-	-	-
71 Interest		96,206,794	(2,745)	606,921	11,431	(16,243,007)
72 Schedule "M" Additions		406,229,218	-	10,061,436	-	1,056,147
73 Schedule "M" Deductions		428,771,671	-	-	-	-
74 Income Before Tax		204,952,316	(56,497,246)	7,235,540	(22,917,295)	(69,399,819)
75						
76 State Income Taxes		9,304,835	(2,564,975)	328,494	(1,040,445)	(3,150,752)
77 Taxable Income		195,647,481	(53,932,271)	6,907,046	(21,876,850)	(66,249,067)
78						
79 Federal Income Taxes + Other		8,249,843	(11,325,777)	1,450,480	(4,594,138)	(13,912,304)
APPROXIMATE PRICE CHANGE		51,101,359	58,398,993	4,983,679	23,732,287	18,304,908

**Pacificorp**  
**Oregon General Rate Case**  
**Adjustment Summary**  
**Twelve Months Ending December 31, 2023**

Exhibit PAC/1002			
	Tab 7	Tab 8	OR Allocated
	Tax Adjustments	Rate Base Adjustments	Results of Operations December 2023
1 Operating Revenues:			
2 General Business Revenues	-	-	1,248,901,150
3 Interdepartmental	-	-	-
4 Special Sales	-	-	92,708,477
5 Other Operating Revenues	-	2,235,548	81,179,990
6 Total Operating Revenues	-	2,235,548	1,422,789,617
7			
8 Operating Expenses:			
9 Steam Production	-	(13,042,384)	238,036,042
10 Nuclear Production	-	-	-
11 Hydro Production	-	-	12,077,585
12 Other Power Supply	-	(297,478)	343,636,569
13 Transmission	-	-	60,587,175
14 Distribution	-	-	116,940,088
15 Customer Accounting	-	-	23,492,890
16 Customer Service & Info	-	-	6,029,376
17 Sales	-	-	-
18 Administrative & General	-	(980,746)	60,742,837
19			
20 Total O&M Expenses	-	(14,320,608)	861,542,561
21			
22 Depreciation	-	(3,093,033)	287,994,295
23 Amortization	-	2,373,437	43,237,301
24 Taxes Other Than Income	6,547,693	-	84,171,808
25 Income Taxes - Federal	(46,790,008)	5,625,758	(61,296,146)
26 Income Taxes - State	79,191	1,274,079	4,230,426
27 Income Taxes - Def Net	40,629,511	(3,623,440)	12,660,019
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	3,165
30			
31 Total Operating Expenses:	466,386	(11,763,808)	1,232,543,429
32			
33 Operating Rev For Return:	(466,386)	13,999,357	190,246,188
34			
35 Rate Base:			
36 Electric Plant In Service	-	285,403,652	8,852,783,093
37 Plant Held for Future Use	-	(9,657,872)	-
38 Misc Deferred Debits	-	(126,476,526)	67,300,330
39 Elec Plant Acq Adj	-	(1,051,423)	701,604
40 Pensions	-	(7,786,953)	-
41 Prepayments	-	-	11,129,917
42 Fuel Stock	-	(7,313,106)	43,192,126
43 Material & Supplies	-	(1,392,651)	81,719,811
44 Working Capital	(379,622)	(609,953)	13,347,565
45 Weatherization Loans	-	-	-
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	(379,622)	131,115,168	9,070,174,446
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	-	(3,746,161)	(3,571,364,011)
52 Accum Prov For Amort	-	-	(218,109,109)
53 Accum Def Income Tax	(50,169,049)	40,243,899	(643,480,187)
54 Unamortized ITC	4,573	-	(45,778)
55 Customer Adv For Const	-	5,089,393	(23,030,533)
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	27,572,240	16,186,182	(415,023,294)
58			
59 Total Rate Base Deductions	(22,592,236)	57,773,313	(4,871,052,912)
60			
61 Total Rate Base:	(22,971,858)	188,888,481	4,199,121,534
62			
63 Return on Rate Base	0.013%	0.136%	4.531%
64			
65 Return on Equity	0.026%	0.260%	4.668%
66			
67 TAX CALCULATION:			
68 Operating Revenue	(6,547,693)	17,275,753	145,840,487
69 Other Deductions			
70 Interest (AFUDC)	(1,090,745)	-	(21,356,078)
71 Interest	(480,344)	3,949,681	84,048,729
72 Schedule "M" Additions	(93,710,028)	9,745,647	333,382,419
73 Schedule "M" Deductions	28,327,582	(4,991,685)	452,107,568
74 Income Before Tax	(127,014,213)	28,063,404	(35,577,313)
75			
76 State Income Taxes	79,191	1,274,079	4,230,426
77 Taxable Income	(127,093,404)	26,789,326	(39,807,739)
78			
79 Federal Income Taxes + Other	(46,790,008)	5,625,758	(61,296,146)
APPROXIMATE PRICE CHANGE	(1,631,974)	(515,983)	154,373,268

Docket No. UE 399  
Exhibit PAC/1002  
Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Sherona L. Cheung  
Oregon Results of Operations – December 2023**

**March 2022**

## Tab 1 - Results

**PacifiCorp**  
**OREGON**  
**Normalized Results of Operations - 2020 PROTOCOL**  
**Twelve Months Ending December 31, 2023**

(1) Test Period 2020 Protocol Revenue Requirement	1,403,274,418	Page 1.1
(2) Normalized General Business Revenues	1,248,901,150	Page 1.1
(3) 2020 Protocol Price Change	<u>154,373,268</u>	Page 1.1

**PacifiCorp  
OREGON**

PAGE 1.1

**Normalized Results of Operations - 2020 PROTOCOL  
Twelve Months Ending December 31, 2023**

	(1)	(2)	(3)	(4)	(5)	(6)
		(3) - (1)	Ref. Page 1.4			(3) + (4) + (5)
				<b>TAM</b>	<b>GRC</b>	
	NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Under Recovery	Requested Non-NPC Related Price Change	Total Normalized Results with Price Change
1 Operating Revenues:						
2 General Business Revenues	288,535,772	960,365,378	1,248,901,150	69,973,978	84,399,290	1,403,274,418
3 Interdepartmental		-	-			-
4 Special Sales	92,708,477	-	92,708,477			92,708,477
5 Other Operating Revenues		81,179,990	81,179,990			81,179,990
6 Total Operating Revenues	<u>381,244,249</u>	<u>1,041,545,368</u>	<u>1,422,789,617</u>	<u>69,973,978</u>	<u>84,399,290</u>	<u>1,577,162,885</u>
7						
8 Operating Expenses:						
9 Steam Production	154,813,423	83,222,619	238,036,042			238,036,042
10 Nuclear Production		-	-			-
11 Hydro Production		12,077,585	12,077,585			12,077,585
12 Other Power Supply	324,792,931	18,843,638	343,636,569			343,636,569
13 Transmission	41,801,335	18,785,840	60,587,175			60,587,175
14 Distribution		116,940,088	116,940,088			116,940,088
15 Customer Accounting		23,492,890	23,492,890		771,495	24,264,385
16 Customer Service & Info		6,029,376	6,029,376			6,029,376
17 Sales		-	-			-
18 Administrative & General		60,742,837	60,742,837			60,742,837
19						
20 Total O&M Expenses	<u>521,407,688</u>	<u>340,134,873</u>	<u>861,542,561</u>	<u>-</u>	<u>771,495</u>	<u>862,314,056</u>
21						
22 Depreciation		287,994,295	287,994,295			287,994,295
23 Amortization		43,237,301	43,237,301			43,237,301
24 Taxes Other Than Income		84,171,808	84,171,808		4,288,376	88,460,183
25 Income Taxes - Federal	(81,030,263)	19,734,117	(61,296,146)	14,027,403	15,904,856	(31,363,887)
26 Income Taxes - State	(6,363,420)	10,593,846	4,230,426	3,176,819	3,602,010	11,009,254
27 Income Taxes - Def Net		12,660,019	12,660,019			12,660,019
28 Investment Tax Credit Adj.		-	-			-
29 Misc Revenue & Expense		3,165	3,165			3,165
30						
31 Total Operating Expenses:	<u>434,014,005</u>	<u>798,529,424</u>	<u>1,232,543,429</u>	<u>17,204,222</u>	<u>24,566,737</u>	<u>1,274,314,388</u>
32						
33 Operating Rev For Return:	<u>(52,769,756)</u>	<u>243,015,944</u>	<u>190,246,188</u>	<u>52,769,756</u>	<u>59,832,554</u>	<u>302,848,497</u>
34						
35 Rate Base:						
36 Electric Plant In Service		8,852,783,093	8,852,783,093			8,852,783,093
37 Plant Held for Future Use		-	-			-
38 Misc Deferred Debits		67,300,330	67,300,330			67,300,330
39 Elec Plant Acq Adj		701,604	701,604			701,604
40 Pension		-	-			-
41 Prepayments		11,129,917	11,129,917			11,129,917
42 Fuel Stock		43,192,126	43,192,126			43,192,126
43 Material & Supplies		81,719,811	81,719,811			81,719,811
44 Working Capital		13,347,565	13,347,565			13,347,565
45 Weatherization Loans		-	-			-
46 Misc Rate Base		-	-			-
47						
48 Total Electric Plant:	<u>-</u>	<u>9,070,174,446</u>	<u>9,070,174,446</u>			<u>9,070,174,446</u>
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec		(3,571,364,011)	(3,571,364,011)			(3,571,364,011)
52 Accum Prov For Amort		(218,109,109)	(218,109,109)			(218,109,109)
53 Accum Def Income Tax		(643,480,187)	(643,480,187)			(643,480,187)
54 Unamortized ITC		(45,778)	(45,778)			(45,778)
55 Customer Adv For Const		(23,030,533)	(23,030,533)			(23,030,533)
56 Customer Service Deposits		-	-			-
57 Misc Rate Base Deductions		(415,023,294)	(415,023,294)			(415,023,294)
58						
59 Total Rate Base Deductions	<u>-</u>	<u>(4,871,052,912)</u>	<u>(4,871,052,912)</u>			<u>(4,871,052,912)</u>
60						
61 Total Rate Base:	<u>-</u>	<u>4,199,121,534</u>	<u>4,199,121,534</u>			<u>4,199,121,534</u>
62						
63 Return on Rate Base			4.531%			7.212%
64						
65 Return on Equity			4.668%			9.800%

Ref. Page 1.2

**PacifiCorp**  
**OREGON**  
**Normalized Results of Operations - 2020 PROTOCOL**  
**Twelve Months Ending December 31, 2023**

**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	960,365,378	84,399,290	1,044,764,668
3 Interdepartmental	-		-
4 Special Sales	-		-
5 Other Operating Revenues	81,179,990		81,179,990
6 Total Operating Revenues	<u>1,041,545,368</u>	<u>84,399,290</u>	<u>1,125,944,658</u>
7			
8 Operating Expenses:			
9 Steam Production	83,222,619		83,222,619
10 Nuclear Production	-		-
11 Hydro Production	12,077,585		12,077,585
12 Other Power Supply	18,843,638		18,843,638
13 Transmission	18,785,840		18,785,840
14 Distribution	116,940,088		116,940,088
15 Customer Accounting	23,492,890	771,495	24,264,385
16 Customer Service & Info	6,029,376		6,029,376
17 Sales	-		-
18 Administrative & General	60,742,837		60,742,837
19			
20 Total O&M Expenses	340,134,873	771,495	340,906,368
21			
22 Depreciation	287,994,295		287,994,295
23 Amortization	43,237,301		43,237,301
24 Taxes Other Than Income	84,171,808	4,288,376	88,460,183
25 Income Taxes - Federal	19,734,117	15,904,856	35,638,973
26 Income Taxes - State	10,593,846	3,602,010	14,195,856
27 Income Taxes - Def Net	12,660,019		12,660,019
28 Investment Tax Credit Adj.	-		-
29 Misc Revenue & Expense	3,165		3,165
30			
31 Total Operating Expenses:	798,529,424	24,566,737	823,096,161
32			
33 Operating Rev For Return:	<u>243,015,944</u>	<u>59,832,554</u>	<u>302,848,497</u>
34			
35 Rate Base:			
36 Electric Plant In Service	8,852,783,093		8,852,783,093
37 Plant Held for Future Use	-		-
38 Misc Deferred Debits	67,300,330		67,300,330
39 Elec Plant Acq Adj	701,604		701,604
40 Pension	-		-
41 Prepayments	11,129,917		11,129,917
42 Fuel Stock	43,192,126		43,192,126
43 Material & Supplies	81,719,811		81,719,811
44 Working Capital	13,347,565		13,347,565
45 Weatherization Loans	-		-
46 Misc Rate Base	-		-
47			
48 Total Electric Plant:	9,070,174,446		9,070,174,446
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	(3,571,364,011)		(3,571,364,011)
52 Accum Prov For Amort	(218,109,109)		(218,109,109)
53 Accum Def Income Tax	(643,480,187)		(643,480,187)
54 Unamortized ITC	(45,778)		(45,778)
55 Customer Adv For Const	(23,030,533)		(23,030,533)
56 Customer Service Deposits	-		-
57 Misc Rate Base Deductions	(415,023,294)		(415,023,294)
58			
59 Total Rate Base Deductions	(4,871,052,912)		(4,871,052,912)
60			
61 Total Rate Base:	<u>4,199,121,534</u>		<u>4,199,121,534</u>
62			
63 Return on Rate Base	5.787%		7.212%
64			
65 Return on Equity	7.073%		9.800%
66			
67 TAX CALCULATION:			
68 Operating Revenue	286,003,926	79,339,420	365,343,345
69 Other Deductions			
70 Interest (AFUDC)	(21,356,078)	-	(21,356,078)
71 Interest	84,048,729	-	84,048,729
72 Schedule "M" Additions	333,382,419	-	333,382,419
73 Schedule "M" Deductions	452,107,568	-	452,107,568
74 Income Before Tax	104,586,126	79,339,420	183,925,546
75			
76 State Income Taxes	10,593,846	3,602,010	14,195,856
77 Taxable Income	<u>93,992,280</u>	<u>75,737,410</u>	<u>169,729,690</u>
78			
79 Federal Income Taxes + Other	<u>19,734,117</u>	<u>15,904,856</u>	<u>35,638,973</u>



**PacifiCorp  
OREGON**

PAGE 1.3

**Normalized Results of Operations - 2020 PROTOCOL  
Twelve Months Ending December 31, 2023**

**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	288,535,772	69,973,978	358,509,750
3 Interdepartmental	-	-	-
4 Special Sales	92,708,477	-	92,708,477
5 Other Operating Revenues	-	-	-
6 Total Operating Revenues	<u>381,244,249</u>	<u>69,973,978</u>	<u>451,218,227</u>
7			
8 Operating Expenses:			
9 Steam Production	154,813,423	-	154,813,423
10 Nuclear Production	-	-	-
11 Hydro Production	-	-	-
12 Other Power Supply	324,792,931	-	324,792,931
13 Transmission	41,801,335	-	41,801,335
14 Distribution	-	-	-
15 Customer Accounting	-	-	-
16 Customer Service & Info	-	-	-
17 Sales	-	-	-
18 Administrative & General	-	-	-
19			
20 Total O&M Expenses	<u>521,407,688</u>	<u>-</u>	<u>521,407,688</u>
21			
22 Depreciation	-	-	-
23 Amortization	-	-	-
24 Taxes Other Than Income	-	-	-
25 Income Taxes - Federal	(81,030,263)	14,027,403	(67,002,860)
26 Income Taxes - State	(6,363,420)	3,176,819	(3,186,602)
27 Income Taxes - Def Net	-	-	-
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	-
30			
31 Total Operating Expenses:	<u>434,014,005</u>	<u>17,204,222</u>	<u>451,218,227</u>
32			
33 Operating Rev For Return:	<u>(52,769,756)</u>	<u>52,769,756</u>	<u>-</u>
34			
35 Rate Base:			
36 Electric Plant In Service	-	-	-
37 Plant Held for Future Use	-	-	-
38 Misc Deferred Debits	-	-	-
39 Elec Plant Acq Adj	-	-	-
40 Pension	-	-	-
41 Prepayments	-	-	-
42 Fuel Stock	-	-	-
43 Material & Supplies	-	-	-
44 Working Capital	-	-	-
45 Weatherization Loans	-	-	-
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	<u>-</u>	<u>-</u>	<u>-</u>
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	-	-	-
52 Accum Prov For Amort	-	-	-
53 Accum Def Income Tax	-	-	-
54 Unamortized ITC	-	-	-
55 Customer Adv For Const	-	-	-
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	-	-	-
58			
59 Total Rate Base Deductions	<u>-</u>	<u>-</u>	<u>-</u>
60			
61 Total Rate Base:	<u>-</u>	<u>-</u>	<u>-</u>
62			
63 Return on Rate Base	N/A		N/A
64			
65 Return on Equity	N/A		N/A
66			
67 TAX CALCULATION:			
68 Operating Revenue	(140,163,439)	69,973,978	(70,189,462)
69 Other Deductions	-	-	-
70 Interest (AFUDC)	-	-	-
71 Interest	-	-	-
72 Schedule "M" Additions	-	-	-
73 Schedule "M" Deductions	-	-	-
74 Income Before Tax	<u>(140,163,439)</u>	<u>69,973,978</u>	<u>(70,189,462)</u>
75			
76 State Income Taxes	<u>(6,363,420)</u>	<u>3,176,819</u>	<u>(3,186,602)</u>
77 Taxable Income	<u>(133,800,019)</u>	<u>66,797,159</u>	<u>(67,002,860)</u>
78			
79 Federal Income Taxes + Other	<u>(81,030,263)</u>	<u>14,027,403</u>	<u>(67,002,860)</u>

**PacifiCorp**  
**OREGON**  
**Normalized Results of Operations - 2020 PROTOCOL**  
**Twelve Months Ending December 31, 2023**

	(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1 Operating Revenues:			
2 General Business Revenues	1,248,901,150	154,373,268	1,403,274,418
3 Interdepartmental	-		
4 Special Sales	92,708,477		
5 Other Operating Revenues	81,179,990		
6 Total Operating Revenues	<u>1,422,789,617</u>		
7			
8 Operating Expenses:			
9 Steam Production	238,036,042		
10 Nuclear Production	-		
11 Hydro Production	12,077,585		
12 Other Power Supply	343,636,569		
13 Transmission	60,587,175		
14 Distribution	116,940,088		
15 Customer Accounting	23,492,890	771,495	24,264,385
16 Customer Service & Info	6,029,376		
17 Sales	-		
18 Administrative & General	60,742,837		
19			
20 Total O&M Expenses	861,542,561		
21			
22 Depreciation	287,994,295		
23 Amortization	43,237,301		
24 Taxes Other Than Income	84,171,808	4,288,376	88,460,183
25 Income Taxes - Federal	(61,296,146)	29,932,259	(31,363,887)
26 Income Taxes - State	4,230,426	6,778,828	11,009,254
27 Income Taxes - Def Net	12,660,019		
28 Investment Tax Credit Adj.	-		
29 Misc Revenue & Expense	3,165		
30			
31 Total Operating Expenses:	1,232,543,429	41,770,958	1,274,314,388
32			
33 Operating Rev For Return:	<u>190,246,188</u>	<u>112,602,309</u>	<u>302,848,497</u>
34			
35 Rate Base:			
36 Electric Plant In Service	8,852,783,093		
37 Plant Held for Future Use	-		
38 Misc Deferred Debits	67,300,330		
39 Elec Plant Acq Adj	701,604		
40 Pensions	-		
41 Prepayments	11,129,917		
42 Fuel Stock	43,192,126		
43 Material & Supplies	81,719,811		
44 Working Capital	13,347,565		
45 Weatherization Loans	-		
46 Misc Rate Base	-		
47			
48 Total Electric Plant:	9,070,174,446	-	9,070,174,446
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	(3,571,364,011)		
52 Accum Prov For Amort	(218,109,109)		
53 Accum Def Income Tax	(643,480,187)		
54 Unamortized ITC	(45,778)		
55 Customer Adv For Const	(23,030,533)		
56 Customer Service Deposits	-		
57 Misc Rate Base Deductions	(415,023,294)		
58			
59 Total Rate Base Deductions	(4,871,052,912)	-	(4,871,052,912)
60			
61 Total Rate Base:	<u>4,199,121,534</u>	<u>-</u>	<u>4,199,121,534</u>
62			
63 Return on Rate Base	4.531%		7.212%
64			
65 Return on Equity	4.668%		9.800%
66			
67 TAX CALCULATION:			
68 Operating Revenue	145,840,487	149,313,397	295,153,884
69 Other Deductions			
70 Interest (AFUDC)	(21,356,078)	-	(21,356,078)
71 Interest	84,048,729	-	84,048,729
72 Schedule "M" Additions	333,382,419	-	333,382,419
73 Schedule "M" Deductions	452,107,568	-	452,107,568
74 Income Before Tax	<u>(35,577,313)</u>	<u>149,313,397</u>	<u>113,736,084</u>
75			
76 State Income Taxes	4,230,426	6,778,828	11,009,254
77 Taxable Income	<u>(39,807,739)</u>	<u>142,534,569</u>	<u>102,726,830</u>
78			
79 Federal Income Taxes + Other	<u>(61,296,146)</u>	<u>29,932,259</u>	<u>(31,363,887)</u>

**PacifiCorp  
OREGON**  
**Normalized Results of Operations - 2020 PROTOCOL**  
**Twelve Months Ending December 31, 2023**

Net Rate Base	\$ 4,199,121,534	Ref. Page 1.1
Return on Rate Base Requested	<u>7.21%</u>	Ref. Page 2.0
Revenues Required to Earn Requested Return	302,848,497	
Less Current Operating Revenues	<u>(190,246,188)</u>	
Increase to Current Revenues	112,602,309	
Net to Gross Bump-up	<u>137.10%</u>	
Price Change Required for Requested Return	<u>\$ 154,373,268</u>	
Requested Price Change	\$ 154,373,268	
Uncollectible Percent	0.500%	Ref. Page 1.6
Increased Uncollectible Expense	<u>\$ 771,495</u>	
Requested Price Change	\$ 154,373,268	
Franchise Tax	2.303%	Ref. Page 1.6
Revenue Tax	0.000%	Ref. Page 1.6
Resource Supplier Tax	0.125%	Ref. Page 1.6
PUC Fees Based on General Business Revenues	0.350%	Ref. Page 1.6
Increase Taxes Other Than Income	<u>\$ 4,288,376</u>	
Requested Price Change	\$ 154,373,268	
Uncollectible Expense	(771,495)	
Taxes Other Than Income	<u>(4,288,376)</u>	
Income Before Taxes	<u>\$ 149,313,397</u>	
State Effective Tax Rate	4.54%	Ref. Page 2.0
State Income Taxes	<u>\$ 6,778,828</u>	
Taxable Income	\$ 142,534,569	
Federal Income Tax Rate	21.00%	Ref. Page 2.0
Federal Income Taxes	<u>\$ 29,932,259</u>	
Operating Income	100.000%	
Net Operating Income	<u>72.942%</u>	Ref. Page 1.6
Net to Gross Bump-Up	<u>137.10%</u>	

**PacifiCorp  
OREGON**  
**Normalized Results of Operations - 2020 PROTOCOL**  
**Twelve Months Ending December 31, 2023**

Operating Revenue	100.000%
Operating Deductions	
Uncollectible Accounts	0.500% See Note (1) Below
Taxes Other - Franchise Tax	2.303%
Taxes Other - Revenue Tax	0.000%
Taxes Other - Resource Supplier	0.125%
PUC Fees Based on General Business Revenues	<u>0.350%</u>
Sub-Total	96.722%
State Income Tax @ 4.54%	<u>4.391%</u>
Sub-Total	92.331%
Federal Income Tax @ 21.00%	<u>19.390%</u>
Net Operating Income	<u><u>72.942%</u></u>

(1) Uncollectible Accounts =  $\frac{6,241,502}{1,248,901,150}$  Pg 2.11, OREGON Situs from Account 904  
Pg. 2.2, General Business Revenues

Pacificorp  
Oregon General Rate Case  
Adjustment Summary  
Twelve Months Ending December 31, 2023

	TOTAL COMPANY UNADJUSTED RESULTS JUNE 2021	OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2021	Tab 3 Revenue Adjustments	Tab 4 O&M Adjustments	Tab 5 Net Power Cost Adjustments	Tab 6 Depreciation & Amortization Adjustments
1 Operating Revenues:						
2 General Business Revenues	5,081,632,249	1,308,339,123	(61,204,592)	1,766,619	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	212,315,668	52,145,322	-	-	40,563,155	-
5 Other Operating Revenues	227,962,549	74,239,841	4,704,600	-	-	-
6 Total Operating Revenues	5,521,910,467	1,434,724,286	(56,499,992)	1,766,619	40,563,155	-
7						
8 Operating Expenses:						
9 Steam Production	997,145,306	256,305,884	-	5,165,696	(14,027,757)	3,634,603
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	76,270,911	19,884,087	-	(7,806,503)	-	-
12 Other Power Supply	1,076,832,156	266,678,359	-	2,779,918	74,475,770	-
13 Transmission	220,828,048	57,410,559	-	155,610	3,021,006	-
14 Distribution	227,788,851	88,583,363	-	28,356,724	-	-
15 Customer Accounting	70,180,739	22,022,443	-	1,470,447	-	-
16 Customer Service & Info	116,029,408	5,610,498	-	418,878	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	296,924,361	86,907,150	-	(25,183,567)	-	-
19						
20 Total O&M Expenses	3,081,999,779	803,402,344	-	5,357,203	63,469,020	3,634,603
21						
22 Depreciation	1,035,081,277	232,580,644	-	-	-	58,506,685
23 Amortization	61,823,778	16,306,178	-	-	-	24,557,686
24 Taxes Other Than Income	212,196,714	79,098,063	-	(1,473,948)	-	-
25 Income Taxes - Federal	(28,741,917)	8,249,843	(11,325,777)	1,450,480	(4,594,138)	(13,912,304)
26 Income Taxes - State	26,781,277	9,304,835	(2,564,975)	328,494	(1,040,445)	(3,150,752)
27 Income Taxes - Def Net	(64,900,993)	(21,612,618)	-	(2,473,765)	-	(259,669)
28 Investment Tax Credit Adj.	(1,703,368)	-	-	-	-	-
29 Misc Revenue & Expense	(1,733,836)	(99,173)	-	102,338	-	-
30						
31 Total Operating Expenses:	4,320,802,712	1,127,230,117	(13,890,752)	3,290,802	57,834,436	69,376,249
32						
33 Operating Rev For Return:	1,201,107,755	307,494,169	(42,609,240)	(1,524,183)	(17,271,281)	(69,376,249)
34						
35 Rate Base:						
36 Electric Plant In Service	31,317,729,025	8,567,379,441	-	-	-	-
37 Plant Held for Future Use	23,896,248	9,657,872	-	-	-	-
38 Misc Deferred Debits	962,744,647	193,776,856	-	-	-	-
39 Elec Plant Acq Adj	14,875,820	1,753,028	-	-	-	-
40 Pensions	28,656,862	7,786,953	-	-	-	-
41 Prepayments	67,554,352	11,129,917	-	-	-	-
42 Fuel Stock	201,471,836	50,505,232	-	-	-	-
43 Material & Supplies	273,026,865	83,112,462	-	-	-	-
44 Working Capital	46,340,902	13,995,191	(131,295)	53,519	546,651	(126,926)
45 Weatherization Loans	199,224,237	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	33,135,520,794	8,939,096,950	(131,295)	53,519	546,651	(126,926)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(9,626,761,743)	(2,815,387,372)	-	-	-	(752,230,479)
52 Accum Prov For Amort	(691,673,798)	(201,534,614)	-	-	-	(16,574,495)
53 Accum Def Income Tax	(2,565,819,019)	(623,521,952)	-	(9,430,521)	-	(602,563)
54 Unamortized ITC	(2,245,487)	(50,351)	-	-	-	-
55 Customer Adv For Const	(104,109,027)	(28,119,926)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(2,269,895,491)	(489,871,272)	-	38,356,344	-	(7,266,788)
58						
59 Total Rate Base Deductions	(15,260,504,564)	(4,158,485,487)	-	28,925,824	-	(776,674,325)
60						
61 Total Rate Base:	17,875,016,231	4,780,611,463	(131,295)	28,979,343	546,651	(776,801,251)
62						
63 Return on Rate Base		6.432%	-0.891%	-0.065%	-0.360%	-0.735%
64						
65 Return on Equity		8.307%	-1.706%	-0.125%	-0.688%	-1.406%
66						
67 TAX CALCULATION:						
68 Operating Revenue		303,436,230	(56,499,992)	(2,218,974)	(22,905,864)	(86,698,974)
69 Other Deductions						
70 Interest (AFUDC)		(20,265,333)	-	-	-	-
71 Interest		96,206,794	(2,745)	606,921	11,431	(16,243,007)
72 Schedule "M" Additions		406,229,218	-	10,061,436	-	1,056,147
73 Schedule "M" Deductions		428,771,671	-	-	-	-
74 Income Before Tax		204,952,316	(56,497,246)	7,235,540	(22,917,295)	(69,399,819)
75						
76 State Income Taxes		9,304,835	(2,564,975)	328,494	(1,040,445)	(3,150,752)
77 Taxable Income		195,647,481	(53,932,271)	6,907,046	(21,876,850)	(66,249,067)
78						
79 Federal Income Taxes + Other		8,249,843	(11,325,777)	1,450,480	(4,594,138)	(13,912,304)
APPROXIMATE PRICE CHANGE		51,101,359	58,398,993	4,983,679	23,732,287	18,304,908

**Pacificorp**  
**Oregon General Rate Case**  
**Adjustment Summary**  
**Twelve Months Ending December 31, 2023**

	Tab 7	Tab 8	OR Allocated
	Tax Adjustments	Rate Base Adjustments	Results of Operations December 2023
1 Operating Revenues:			
2 General Business Revenues	-	-	1,248,901,150
3 Interdepartmental	-	-	-
4 Special Sales	-	-	92,708,477
5 Other Operating Revenues	-	2,235,548	81,179,990
6 Total Operating Revenues	-	2,235,548	1,422,789,617
7			
8 Operating Expenses:			
9 Steam Production	-	(13,042,384)	238,036,042
10 Nuclear Production	-	-	-
11 Hydro Production	-	-	12,077,585
12 Other Power Supply	-	(297,478)	343,636,569
13 Transmission	-	-	60,587,175
14 Distribution	-	-	116,940,088
15 Customer Accounting	-	-	23,492,890
16 Customer Service & Info	-	-	6,029,376
17 Sales	-	-	-
18 Administrative & General	-	(980,746)	60,742,837
19			
20 Total O&M Expenses	-	(14,320,608)	861,542,561
21			
22 Depreciation	-	(3,093,033)	287,994,295
23 Amortization	-	2,373,437	43,237,301
24 Taxes Other Than Income	6,547,693	-	84,171,808
25 Income Taxes - Federal	(46,790,008)	5,625,758	(61,296,146)
26 Income Taxes - State	79,191	1,274,079	4,230,426
27 Income Taxes - Def Net	40,629,511	(3,623,440)	12,660,019
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	3,165
30			
31 Total Operating Expenses:	466,386	(11,763,808)	1,232,543,429
32			
33 Operating Rev For Return:	(466,386)	13,999,357	190,246,188
34			
35 Rate Base:			
36 Electric Plant In Service	-	285,403,652	8,852,783,093
37 Plant Held for Future Use	-	(9,657,872)	-
38 Misc Deferred Debits	-	(126,476,526)	67,300,330
39 Elec Plant Acq Adj	-	(1,051,423)	701,604
40 Pensions	-	(7,786,953)	-
41 Prepayments	-	-	11,129,917
42 Fuel Stock	-	(7,313,106)	43,192,126
43 Material & Supplies	-	(1,392,651)	81,719,811
44 Working Capital	(379,622)	(609,953)	13,347,565
45 Weatherization Loans	-	-	-
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	(379,622)	131,115,168	9,070,174,446
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	-	(3,746,161)	(3,571,364,011)
52 Accum Prov For Amort	-	-	(218,109,109)
53 Accum Def Income Tax	(50,169,049)	40,243,899	(643,480,187)
54 Unamortized ITC	4,573	-	(45,778)
55 Customer Adv For Const	-	5,089,393	(23,030,533)
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	27,572,240	16,186,182	(415,023,294)
58			
59 Total Rate Base Deductions	(22,592,236)	57,773,313	(4,871,052,912)
60			
61 Total Rate Base:	(22,971,858)	188,888,481	4,199,121,534
62			
63 Return on Rate Base	0.013%	0.136%	4.531%
64			
65 Return on Equity	0.026%	0.260%	4.668%
66			
67 TAX CALCULATION:			
68 Operating Revenue	(6,547,693)	17,275,753	145,840,487
69 Other Deductions			
70 Interest (AFUDC)	(1,090,745)	-	(21,356,078)
71 Interest	(480,344)	3,949,681	84,048,729
72 Schedule "M" Additions	(93,710,028)	9,745,647	333,382,419
73 Schedule "M" Deductions	28,327,582	(4,991,685)	452,107,568
74 Income Before Tax	(127,014,213)	28,063,404	(35,577,313)
75			
76 State Income Taxes	79,191	1,274,079	4,230,426
77 Taxable Income	(127,093,404)	26,789,326	(39,807,739)
78			
79 Federal Income Taxes + Other	(46,790,008)	5,625,758	(61,296,146)
APPROXIMATE PRICE CHANGE	(1,631,974)	(515,983)	154,373,268

# Tab \$ - Rebad

**PacifiCorp**  
**RESULTS OF OPERATIONS**

USER SPECIFIC INFORMATION

STATE:	OREGON
PERIOD:	TWELVE MONTHS ENDING DECEMBER 31, 2023
FILE:	OR JAM Dec 2023 GRC
PREPARED BY:	Revenue Requirement Department
DATE:	2/18/2022
TIME:	4:19:42 PM
TYPE OF RATE BASE:	Year End
ALLOCATION METHOD:	<b>2020 PROTOCOL</b>
FERC JURISDICTION:	Separate Jurisdiction
8 OR 12 CP:	12 Coincident Peaks
DEMAND %	75% Demand
ENERGY %	25% Energy

TAX INFORMATION

<u>TAX RATE ASSUMPTIONS:</u>	<u>TAX RATE</u>
FEDERAL RATE	21.00%
STATE EFFECTIVE RATE	4.54%
TAX GROSS UP FACTOR	1.326
FEDERAL/STATE COMBINED RATE	24.587%

CAPITAL STRUCTURE INFORMATION

	<u>CAPITAL STRUCTURE</u>	<u>EMBEDDED COST</u>	<u>WEIGHTED COST</u>
DEBT	47.74%	4.38%	2.09%
PREFERRED	0.01%	6.75%	0.00%
COMMON	52.25%	9.80%	5.12%
	<u>100.00%</u>		<u>7.21%</u>

OTHER INFORMATION

For information and support regarding capital structure and cost of debt, see testimony of Ms. Nikki L. Koblha.  
For information and support regarding return on common equity, see testimony of Ms. Ann E. Bulkley.



2020 PROTOCOL  
Year End

RESULTS OF OPERATIONS SUMMARY

Description of Account Summary:	Ref	JUNE 2021 UNADJUSTED RESULTS		DECEMBER 2023 NORMALIZED RESULTS	
		TOTAL	OREGON	TOTAL	OREGON
1 Operating Revenues					
2     General Business Revenues	2.2	5,081,632,249	1,308,339,123	5,022,194,276	1,248,901,150
3     Interdepartmental	2.2	0	0	0	0
4     Special Sales	2.2	212,315,668	52,145,322	368,049,381	92,708,477
5     Other Operating Revenues	2.3	227,962,549	74,239,841	248,243,892	81,179,990
6     Total Operating Revenues	2.3	5,521,910,467	1,434,724,286	5,638,487,549	1,422,789,617
7					
8 Operating Expenses:					
9     Steam Production	2.5	997,145,306	256,305,884	924,349,714	238,036,042
10     Nuclear Production	2.5	0	0	0	0
11     Hydro Production	2.6	76,270,911	19,884,087	46,326,914	12,077,585
12     Other Power Supply	2.7, .8	1,076,832,156	266,678,359	1,362,512,151	343,636,569
13     Transmission	2.9	220,828,048	57,410,559	232,875,087	60,587,175
14     Distribution	2.10	227,788,851	88,583,363	265,354,371	116,940,088
15     Customer Accounting	2.11	70,180,739	22,022,443	75,200,784	23,492,890
16     Customer Service & Infor	2.12	116,029,408	5,610,498	126,454,909	6,029,376
17     Sales	2.12	0	0	0	0
18     Administrative & General	2.13	296,924,361	86,907,150	193,298,120	60,742,837
19					
20     Total O & M Expenses	2.13	3,081,999,779	803,402,344	3,226,372,050	861,542,561
21					
22     Depreciation	2.14	1,035,081,277	232,580,644	1,271,626,317	287,994,295
23     Amortization	2.15	61,823,778	16,306,178	90,272,115	43,237,301
24     Taxes Other Than Income	2.15	212,196,714	79,098,063	234,822,593	84,171,808
25     Income Taxes - Federal	2.18	(28,741,917)	8,249,843	(165,208,190)	(61,296,146)
26     Income Taxes - State	2.18	26,781,277	9,304,835	30,934,209	4,230,426
27     Income Taxes - Def Net	2.16	(64,900,993)	(21,612,618)	(53,680,948)	12,660,019
28     Investment Tax Credit Adj.	2.15	(1,703,368)	0	(1,055,733)	0
29     Misc Revenue & Expense	2.3	(1,733,836)	(99,173)	(1,503,560)	3,165
30					
31     Total Operating Expenses	2.18	4,320,802,712	1,127,230,117	4,632,578,853	1,232,543,429
32					
33 Operating Revenue for Return		1,201,107,755	307,494,169	1,005,908,696	190,246,188
34					
35 Rate Base:					
36     Electric Plant in Service	2.26	31,317,729,025	8,567,379,441	32,579,238,234	8,852,783,093
37     Plant Held for Future Use	2.26	23,896,248	9,657,872	0	0
38     Misc Deferred Debits	2.28	962,744,647	193,776,856	459,239,830	67,300,330
39     Elec Plant Acq Adj	2.26,.27	14,875,820	1,753,028	10,842,796	701,604
40     Pensions	2.27	28,656,862	7,786,953	0	0
41     Prepayments	2.28	67,554,352	11,129,917	67,554,352	11,129,917
42     Fuel Stock	2.27	201,471,836	50,505,232	172,298,918	43,192,126
43     Material & Supplies	2.28	273,026,865	83,112,462	267,684,968	81,719,811
44     Working Capital	2.28	46,340,902	13,995,191	43,506,974	13,347,565
45     Weatherization Loans	2.27	199,224,237	0	199,224,237	0
46     Miscellaneous Rate Base	2.29	0	0	0	0
47					
48     Total Electric Plant		33,135,520,794	8,939,096,950	33,799,590,309	9,070,174,446
49					
50 Rate Base Deductions:					
51     Accum Prov For Depr	2.32	(9,626,761,743)	(2,815,387,372)	(12,050,132,685)	(3,571,364,011)
52     Accum Prov For Amort	2.33	(691,673,798)	(201,534,614)	(749,438,517)	(218,109,109)
53     Accum Def Income Taxes	2.30	(2,565,819,019)	(623,521,952)	(2,702,858,647)	(643,480,187)
54     Unamortized ITC	2.30	(2,245,487)	(50,351)	(2,339,440)	(45,778)
55     Customer Adv for Const	2.29	(104,109,027)	(28,119,926)	(104,109,027)	(23,030,533)
56     Customer Service Deposits	2.29	0	0	0	0
57     Misc. Rate Base Deductions	2.29	(2,269,895,491)	(489,871,272)	(2,038,041,418)	(415,023,294)
58					
59     Total Rate Base Deductions		(15,260,504,564)	(4,158,485,487)	(17,646,919,733)	(4,871,052,912)
60					
61 Total Rate Base		17,875,016,231	4,780,611,463	16,152,670,576	4,199,121,534
62					
63 Return on Rate Base		6.771%	6.432%	6.228%	4.531%
64					
65 Return on Equity		8.508%	8.307%	7.915%	4.668%
66 Net Power Costs			406,077,514	1,683,499,703	428,699,211
67 100 Basis Points in Equity:			24,978,695	84,397,704	21,940,410
68     Revenue Requirement Impact			33,122,356	111,913,405	29,093,517
69     Rate Base Decrease			(359,167,463)	(1,250,335,049)	(434,195,416)

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End	ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	UNADJUSTED RESULTS	NORMALIZED RESULTS	
						TOTAL	OREGON	
						TOTAL	OREGON	
70	Sales to Ultimate Customers							
71	440	Residential Sales						
72		0		S		2,032,842,216	658,842,617	
73								
74					B1	2,032,842,216	658,842,617	
75								
76	442	Commercial & Industrial Sales						
77		0		S		3,031,724,688	643,689,980	
78		P		SE		-	-	
79		PT		SG		-	-	
80								
81								
82					B1	3,031,724,688	643,689,980	
83								
84	444	Public Street & Highway Lighting						
85		0		S		17,065,345	5,806,526	
86		0		SO		-	-	
87					B1	17,065,345	5,806,526	
88								
89	445	Other Sales to Public Authority						
90		0		S		-	-	
91								
92					B1	-	-	
93								
94	448	Interdepartmental						
95		DPW		S		-	-	
96		GP		SO		-	-	
97					B1	-	-	
98								
99	<b>Total Sales to Ultimate Customers</b>					<b>B1</b>	<b>5,081,632,249</b>	<b>1,308,339,123</b>
100								
101								
102								
103	447	Sales for Resale-Non NPC						
104		P		S		12,440,401	-	
105					B1	12,440,401	-	
106								
107	447NPC	Sales for Resale-NPC						
108		P		SG		203,582,710	53,074,709	
109		P		SE		(3,707,443)	(929,387)	
110		P		SG		-	-	
111					B1	199,875,267	52,145,322	
112								
113		Total Sales for Resale			B1	212,315,668	52,145,322	
114								
115	449	Provision for Rate Refund						
116		P		S		-	-	
117		P		SG		(3,239,918)	(844,658)	
118								
119								
120					B1	(3,239,918)	(844,658)	
121								
122	<b>Total Sales from Electricity</b>					<b>B1</b>	<b>5,290,707,999</b>	<b>1,359,639,787</b>
123	450	Forfeited Discounts & Interest						
124		CUST		S		6,599,968	(19,497)	
125		CUST		SO		-	-	
126					B1	6,599,968	(19,497)	
127								
128	451	Misc Electric Revenue						
129		CUST		S		8,210,111	1,545,976	
130		GP		SG		-	-	
131		GP		SO		52,826	14,354	
132					B1	8,262,937	1,560,331	
133								
134	453	Water Sales						
135		P		SG		7,350	1,916	
136					B1	7,350	1,916	
137								
138	454	Rent of Electric Property						
139		DPW		S		10,236,067	4,606,685	
140		T		SG		4,867,665	1,269,017	
141		T		SG		-	-	
142		GP		SO		3,142,114	853,809	
143					B1	18,245,846	6,729,512	



2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End		BUS		UNADJUSTED RESULTS		NORMALIZED RESULTS		
ACCT	DESCRIP	FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
215	500							
216		P	SG		13,865,751	3,614,849	14,632,305	3,814,692
217		P	SG		1,084,539	282,743	1,173,480	305,930
218		P	SG		-	-	(57)	(15)
219				B2	14,950,290	3,897,592	15,805,728	4,120,607
220								
221	501							
222		P	S		6,207,125	4,921,418	6,716,162	5,325,016
223		P	SE		16,755,152	4,200,204	32,628,114	8,179,260
224		P	SE		-	-	-	-
225		P	SE		-	-	-	-
226		P	SE		264,509	66,307	286,201	71,745
227				B2	23,226,786	9,187,929	39,630,478	13,576,021
228								
229	501NPC							
230		P	S		137,244	-	-	-
231		P	SE		637,368,410	159,776,374	582,045,698	145,908,002
232		P	SE		-	-	-	-
233		P	SE		-	-	-	-
234		P	SE		31,040,758	7,781,339	31,040,758	7,781,339
235				B2	668,546,412	167,557,713	613,086,456	153,689,341
236								
237				B2	691,773,198	176,745,643	652,716,933	167,265,362
238								
239	502							
240		P	SG		75,504,557	19,684,296	81,175,898	21,162,834
241		P	SG		4,617,621	1,203,830	4,996,305	1,302,554
242		P	SG		-	-	1	0
243				B2	80,122,178	20,888,126	86,172,205	22,465,388
244								
245	503							
246		P	SE		-	-	(2,433)	(610)
247				B2	-	-	(2,433)	(610)
248								
249	503NPC							
250		P	SE		5,119,912	1,283,466	4,484,106	1,124,082
251				B2	5,119,912	1,283,466	4,484,106	1,124,082
252								
253	505							
254		P	SG		1,041,685	271,571	1,125,294	293,368
255		P	SG		131,171	34,197	141,928	37,001
256		P	SG		-	-	-	-
257				B2	1,172,856	305,768	1,267,222	330,369
258								
259	506							
260		P	SG		57,377,431	14,958,493	61,257,299	15,969,987
261		P	SG		-	-	(54,132,080)	(14,112,418)
262		P	SG		1,448,672	377,674	1,567,475	408,646
263				B2	58,826,103	15,336,166	8,692,695	2,266,215
264								
265	507							
266		P	SG		466,659	121,660	504,929	131,637
267		P	SG		-	-	-	-
268		P	SG		237	62	256	67
269				B2	466,896	121,721	505,186	131,704
270								
271	510							
272		P	SG		5,990,074	1,561,633	6,340,605	1,653,017
273		P	SG		1,064,231	277,449	1,138,745	296,875
274		P	SG		-	-	608,863	158,733
275				B2	7,054,305	1,839,081	8,088,213	2,108,625
276								
277								
278								
279	511							
280		P	SG		22,011,978	5,738,598	23,429,619	6,108,182
281		P	SG		2,549,103	664,560	2,727,582	711,090
282		P	SG		-	-	-	-
283				B2	24,561,081	6,403,158	26,157,201	6,819,272
284								
285	512							
286		P	SG		67,917,271	17,706,265	72,317,868	18,853,516
287		P	SG		1,744,893	454,900	1,867,049	486,746
288		P	SG		-	-	-	-
289				B2	69,662,164	18,161,164	74,184,917	19,340,261
290								
291	513							
292		P	SG		31,093,354	8,106,144	33,104,634	8,630,491
293		P	SG		300,806	78,421	321,867	83,912
294		P	SG		-	-	-	-
295				B2	31,394,160	8,184,565	33,426,501	8,714,403



2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
375								
376	538	Electric Expenses						
377		P	DGP		-	-	-	-
378		P	SG		-	-	-	-
379		P	SG		-	-	-	-
380								
381				B2	-	-	-	-
382								
383	539	Misc. Hydro Expenses						
384		P	SG		-	-	59	15
385		P	SG		11,778,612	3,070,725	12,639,671	3,295,206
386		P	SG		6,544,109	1,706,072	6,966,095	1,816,085
387								
388								
389				B2	18,322,722	4,776,796	19,605,825	5,111,306
390								
391	540	Rents (Hydro Generation)						
392		P	SG		-	-	-	-
393		P	SG		1,430,079	372,827	1,565,719	408,188
394		P	SG		63,838	16,643	69,893	18,221
395								
396				B2	1,493,917	389,469	1,635,612	426,410
397								
398	541	Maint Supervision & Engineering						
399		P	SG		-	-	-	-
400		P	SG		384	100	412	107
401		P	SG		-	-	-	-
402								
403				B2	384	100	412	107
404								
405	542	Maintenance of Structures						
406		P	SG		-	-	-	-
407		P	SG		742,250	193,507	790,556	206,101
408		P	SG		72,934	19,014	77,412	20,182
409								
410				B2	815,184	212,521	867,968	226,282
411								
412								
413								
414								
415	543	Maintenance of Dams & Waterways						
416		P	SG		-	-	-	-
417		P	SG		693,668	180,842	738,577	192,549
418		P	SG		354,924	92,530	378,242	98,609
419								
420				B2	1,048,592	273,371	1,116,819	291,159
421								
422	544	Maintenance of Electric Plant						
423		P	SG		-	-	-	-
424		P	SG		1,627,801	424,373	1,729,586	450,909
425		P	SG		250,736	65,368	265,905	69,322
426								
427				B2	1,878,537	489,741	1,995,491	520,231
428								
429	545	Maintenance of Misc. Hydro Plant						
430		P	SG		-	-	-	-
431		P	SG		-	-	-	-
432		P	SG		33,000,000	8,603,213	-	-
433		P	SG		3,005,661	783,586	3,207,950	836,324
434		P	SG		836,709	218,133	894,308	233,149
435								
436				B2	36,842,370	9,604,932	4,102,258	1,069,473
437								
438		<b>Total Hydraulic Power Generation</b>		<b>B2</b>	<b>76,270,911</b>	<b>19,884,087</b>	<b>46,326,914</b>	<b>12,077,585</b>
439								
440	546	Operation Super & Engineering						
441		P	SG		320,354	83,517	348,117	90,755
442		P	SG		-	-	-	-
443		P	SG		-	-	(13)	(3)
444				B2	320,354	83,517	348,104	90,752
445								
446	547	Fuel-Non-NPC						
447		P	SE		-	-	-	-
448		P	SE		-	-	-	-
449				B2	-	-	-	-
450								
451	547NPC	Fuel-NPC						
452		P	SE		289,072,443	72,465,071	308,846,992	77,422,181
453		P	SE		1,980,087	496,371	1,980,087	496,371
454				B2	291,052,531	72,961,442	310,827,079	77,918,552

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
455								
456	548	Generation Expense						
457		P	SG		17,649,317	4,601,237	19,009,367	4,955,807
458		P	SG		383,214	99,905	413,062	107,687
459		P	SG		-	-	(302)	(79)
460				B2	18,032,530	4,701,142	19,422,127	5,063,415
461								
462	549	Miscellaneous Other						
463		P	S		32,386	32,386	34,592	34,592
464		P	SG		4,035,159	1,051,980	4,255,949	1,109,540
465		P	SG		4,490,304	1,170,638	4,871,468	1,270,008
466		P	SG		-	-	(33,430)	(8,715)
467		P	SG		-	-	-	-
468				B2	8,557,850	2,255,004	9,128,579	2,405,425
469								
470								
471								
472								
473	550	Rents						
474		P	S		377,689	377,689	410,642	410,642
475		P	SG		-	-	-	-
476		P	SG		40,789	10,634	44,347	11,561
477		P	SG		7,423,249	1,935,266	8,070,924	2,104,117
478				B2	7,841,726	2,323,589	8,525,913	2,526,321
479								
480	551	Maint Supervision & Engineering						
481		P	SG		-	-	-	-
482				B2	-	-	-	-
483								
484	552	Maintenance of Structures						
485		P	SG		2,300,976	599,872	2,446,430	637,793
486		P	SG		52,439	13,671	55,565	14,486
487		P	SG		-	-	-	-
488				B2	2,353,416	613,543	2,501,995	652,279
489								
490	553	Maint of Generation & Electric Plant						
491		P	SG		3,849,587	1,003,600	4,096,006	1,067,843
492		P	SG		11,075,955	2,887,539	11,843,830	3,087,727
493		P	SG		235,783	61,469	250,925	65,417
494		P	SG		-	-	2,193,945	571,969
495				B2	15,161,325	3,952,609	18,384,706	4,792,956
496								
497	554	Maintenance of Misc. Other						
498		P	SG		2,049,813	534,393	2,192,690	571,642
499		P	SG		1,006,710	262,453	1,077,054	280,792
500		P	SG		75,591	19,707	80,287	20,931
501		P	SG		-	-	-	-
502				B2	3,132,114	816,553	3,350,031	873,365
503								
504		<b>Total Other Power Generation</b>		<b>B2</b>	<b>346,451,846</b>	<b>87,707,400</b>	<b>372,488,535</b>	<b>94,323,065</b>
505								
506								
507	555	Purchased Power-Non NPC						
508		DMSC	S		3,990,510	-	3,990,510	-
509					3,990,510	-	3,990,510	-
510								
511	555NPC	Purchased Power-NPC						
512		P	S		10,277,762	-	(430,221)	(430,221)
513		P	SE		62,781,784	15,738,222	44,724,911	11,211,701
514		Seasonal Conl P	SG		621,018,560	161,901,663	905,599,544	236,092,898
515		P	DGP		-	-	-	-
516					694,078,107	177,639,885	949,894,234	246,874,378
517								
518		<b>Total Purchased Power</b>		<b>B2</b>	<b>698,068,616</b>	<b>177,639,885</b>	<b>953,884,743</b>	<b>246,874,378</b>
519								
520	556	System Control & Load Dispatch						
521		P	SG		596,144	155,417	639,604	166,747
522								
523				B2	596,144	155,417	639,604	166,747
524								
525								
526								
527	557	Other Expenses						
528		P	S		6,878,698	3,050,781	7,476,612	3,316,961
529		P	SG		34,992,756	9,122,731	38,177,818	9,953,088
530		P	SGCT		-	-	-	-
531		P	SE		8,552	2,144	9,298	2,331
532		P	SG		-	-	-	-
533		P	TROJP		-	-	-	-
534								
535				B2	41,880,006	12,175,656	45,663,727	13,272,379

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
ACCT	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
536								
537	Embedded Cost Differentials							
538	Company Owned Hydro	P	DGP		-	-	-	-
539	Company Owned Hydro	P	SG		-	-	-	-
540	Mid-C Contract	P	MC		-	-	-	-
541	Mid-C Contract	P	SG		-	-	-	-
542	Existing QF Contracts	P	S		-	-	-	-
543	Existing QF Contracts	P	SG		-	-	-	-
544								
545								
546								
547								
548								
549								
550	2020 Protocol Adjustment							
551	Baseline ECD	P	S		(10,164,458)	(11,000,000)	(10,164,458)	(11,000,000)
552		P	S		-	-	-	-
553	2020 Protocol Adjustment				(10,164,458)	(11,000,000)	(10,164,458)	(11,000,000)
554								
555	<b>Total Other Power Supply</b>			<b>B2</b>	<b>730,380,310</b>	<b>178,970,959</b>	<b>990,023,617</b>	<b>249,313,504</b>
556								
557	<b>Total Production Expense</b>			<b>B2</b>	<b>2,150,248,373</b>	<b>542,868,330</b>	<b>2,333,188,779</b>	<b>593,750,196</b>
558								
559								
560	Summary of Production Expense by Factor							
561	S				17,736,957	(2,617,726)	8,033,839	(2,343,010)
562	SG				1,088,119,808	283,676,556	1,319,111,207	343,896,803
563	SE				1,044,391,607	261,809,499	1,006,043,734	252,196,403
564	SNPPH				-	-	-	-
565	TROJP				-	-	-	-
566	SGCT				-	-	-	-
567	DGP				-	-	-	-
568	DEU				-	-	-	-
569	DEP				-	-	-	-
570	SNPPS				-	-	-	-
571	SNPPO				-	-	-	-
572	DGU				-	-	-	-
573	MC				-	-	-	-
574	SSGCT				-	-	-	-
575	SSECT				-	-	-	-
576	SSGC				-	-	-	-
577	SSGCH				-	-	-	-
578	SSECH				-	-	-	-
579	Total Production Expense by Factor				2,150,248,373	542,868,330	2,333,188,779	593,750,196
580	560 Operation Supervision & Engineering							
581	T		SG		8,985,016	2,342,424	9,473,335	2,469,731
582	T		SG		-	-	(934)	(243)
583								
584				<b>B2</b>	<b>8,985,016</b>	<b>2,342,424</b>	<b>9,472,401</b>	<b>2,469,487</b>
585								
586	561 Load Dispatching							
587	T		SG		17,775,685	4,634,182	18,688,869	4,872,252
588	T		SG		-	-	(149)	(39)
589								
590				<b>B2</b>	<b>17,775,685</b>	<b>4,634,182</b>	<b>18,688,721</b>	<b>4,872,213</b>
591	562 Station Expense							
592	T		SG		3,230,138	842,108	3,394,366	884,923
593	T		SG		-	-	-	-
594								
595				<b>B2</b>	<b>3,230,138</b>	<b>842,108</b>	<b>3,394,366</b>	<b>884,923</b>
596								
597	563 Overhead Line Expense							
598	T		SG		961,278	250,608	1,010,072	263,329
599	T		SG		-	-	-	-
600								
601				<b>B2</b>	<b>961,278</b>	<b>250,608</b>	<b>1,010,072</b>	<b>263,329</b>
602								
603	564 Underground Line Expense							
604	T		SG		-	-	-	-
605								
606				<b>B2</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
607								
608	565 Transmission of Electricity by Others							
609	T		SG		-	-	-	-
610	T		SE		-	-	-	-
611								
612								
613	565NPC Transmission of Electricity by Others-NPC							
614	T		SG		133,395,046	34,776,545	148,428,446	38,695,804
615	T		SE		15,971,607	4,003,784	12,388,361	3,105,531
616					149,366,653	38,780,329	160,816,807	41,801,335
617								
618	Total Transmission of Electricity by Others			<b>B2</b>	<b>149,366,653</b>	<b>38,780,329</b>	<b>160,816,807</b>	<b>41,801,335</b>



2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
619								
620	566	Misc. Transmission Expense						
621		T	SG		3,609,107	940,907	3,776,647	984,585
622		T	SG		-	-	(4,743,194)	(1,236,567)
623								
624				B2	<u>3,609,107</u>	<u>940,907</u>	<u>(966,547)</u>	<u>(251,982)</u>
625								
626	567	Rents - Transmission						
627		T	SG		2,481,704	646,989	2,597,335	677,134
628		T	SG		-	-	-	-
629								
630				B2	<u>2,481,704</u>	<u>646,989</u>	<u>2,597,335</u>	<u>677,134</u>
631								
632	568	Maint Supervision & Engineering						
633		T	SG		845,051	220,308	890,277	232,098
634		T	SG		-	-	-	-
635								
636				B2	<u>845,051</u>	<u>220,308</u>	<u>890,277</u>	<u>232,098</u>
637								
638	569	Maintenance of Structures						
639		T	SG		5,239,955	1,366,074	5,598,731	1,459,608
640		T	SG		-	-	-	-
641								
642				B2	<u>5,239,955</u>	<u>1,366,074</u>	<u>5,598,731</u>	<u>1,459,608</u>
643								
644	570	Maintenance of Station Equipment						
645		T	SG		10,323,490	2,691,369	11,004,857	2,869,004
646		T	SG		-	-	(0)	(0)
647								
648				B2	<u>10,323,490</u>	<u>2,691,369</u>	<u>11,004,857</u>	<u>2,869,004</u>
649								
650	571	Maintenance of Overhead Lines						
651		T	SG		17,662,920	4,604,784	19,036,251	4,962,816
652		T	SG		-	-	957,228	249,552
653								
654				B2	<u>17,662,920</u>	<u>4,604,784</u>	<u>19,993,479</u>	<u>5,212,368</u>
655								
656	572	Maintenance of Underground Lines						
657		T	SG		169,970	44,312	182,705	47,632
658		T	SG		-	-	-	-
659								
660				B2	<u>169,970</u>	<u>44,312</u>	<u>182,705</u>	<u>47,632</u>
661								
662	573	Maint of Misc. Transmission Plant						
663		T	SG		177,081	46,166	191,882	50,024
664		T	SG		-	-	-	-
665								
666				B2	<u>177,081</u>	<u>46,166</u>	<u>191,882</u>	<u>50,024</u>
667								
668		<b>Total Transmission Expense</b>		<b>B2</b>	<b><u>220,828,048</u></b>	<b><u>57,410,559</u></b>	<b><u>232,875,087</u></b>	<b><u>60,587,175</u></b>
669								
670		Summary of Transmission Expense by Factor						
671		SE			15,971,607	4,003,784	12,388,361	3,105,531
672		SG			204,856,441	53,406,775	220,486,725	57,481,643
673		SNPT			-	-	-	-
674		<b>Total Transmission Expense by Factor</b>			<b><u>220,828,048</u></b>	<b><u>57,410,559</u></b>	<b><u>232,875,087</u></b>	<b><u>60,587,175</u></b>
675	580	Operation Supervision & Engineering						
676		DPW	S		1,694,447	430,541	1,801,731	453,473
677		DPW	SNPD		8,121,601	2,149,999	8,573,477	2,269,622
678				B2	<u>9,816,048</u>	<u>2,580,540</u>	<u>10,375,209</u>	<u>2,723,095</u>
679								
680	581	Load Dispatching						
681		DPW	S		-	-	-	-
682		DPW	SNPD		12,715,437	3,366,106	13,409,240	3,549,774
683				B2	<u>12,715,437</u>	<u>3,366,106</u>	<u>13,409,240</u>	<u>3,549,774</u>
684								
685	582	Station Expense						
686		DPW	S		4,235,076	1,104,470	4,518,626	1,181,026
687		DPW	SNPD		17,180	4,548	18,451	4,884
688				B2	<u>4,252,256</u>	<u>1,109,018</u>	<u>4,537,077</u>	<u>1,185,910</u>
689								
690	583	Overhead Line Expenses						
691		DPW	S		9,361,055	1,780,369	9,917,899	1,887,265
692		DPW	SNPD		166	44	175	46
693				B2	<u>9,361,221</u>	<u>1,780,413</u>	<u>9,918,075</u>	<u>1,887,312</u>
694								
695	584	Underground Line Expense						
696		DPW	S		417	417	448	448
697		DPW	SNPD		-	-	-	-
698				B2	<u>417</u>	<u>417</u>	<u>448</u>	<u>448</u>
699								
700	585	Street Lighting & Signal Systems						
701		DPW	S		-	-	-	-
702		DPW	SNPD		323,751	85,705	342,813	90,751
703				B2	<u>323,751</u>	<u>85,705</u>	<u>342,813</u>	<u>90,751</u>

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
704								
705	586	Meter Expenses						
706		DPW	S		2,750,524	1,272,828	2,912,130	1,347,604
707		DPW	SNPD		-	-	-	-
708				B2	<u>2,750,524</u>	<u>1,272,828</u>	<u>2,912,130</u>	<u>1,347,604</u>
709								
710	587	Customer Installation Expenses						
711		DPW	S		16,553,911	6,350,268	17,539,599	6,725,086
712		DPW	SNPD		-	-	-	-
713				B2	<u>16,553,911</u>	<u>6,350,268</u>	<u>17,539,599</u>	<u>6,725,086</u>
714								
715	588	Misc. Distribution Expenses						
716		DPW	S		415,049	(115,145)	444,092	(122,388)
717		DPW	SNPD		662,605	175,409	660,689	174,902
718				B2	<u>1,077,654</u>	<u>60,263</u>	<u>1,104,782</u>	<u>52,513</u>
719								
720	589	Rents						
721		DPW	S		3,526,824	1,872,042	3,779,738	2,010,384
722		DPW	SNPD		25,331	6,706	27,235	7,210
723				B2	<u>3,552,155</u>	<u>1,878,748</u>	<u>3,806,973</u>	<u>2,017,594</u>
724								
725	590	Maint Supervision & Engineering						
726		DPW	S		2,797,810	822,012	2,961,133	870,564
727		DPW	SNPD		2,560,779	677,905	2,692,533	712,784
728				B2	<u>5,358,589</u>	<u>1,499,917</u>	<u>5,653,666</u>	<u>1,583,348</u>
729								
730	591	Maintenance of Structures						
731		DPW	S		1,756,099	500,380	1,902,591	542,121
732		DPW	SNPD		59,698	15,804	64,666	17,119
733				B2	<u>1,815,797</u>	<u>516,184</u>	<u>1,967,257</u>	<u>559,240</u>
734								
735	592	Maintenance of Station Equipment						
736		DPW	S		7,199,867	2,722,618	7,650,339	2,892,483
737		DPW	SNPD		1,565,281	414,371	1,655,910	438,362
738				B2	<u>8,765,148</u>	<u>3,136,989</u>	<u>9,306,249</u>	<u>3,330,846</u>
739	593	Maintenance of Overhead Lines						
740		DPW	S		110,312,452	55,025,939	139,570,845	81,068,804
741		DPW	SNPD		2,450,344	648,670	3,391,945	897,936
742				B2	<u>112,762,796</u>	<u>55,674,609</u>	<u>142,962,791</u>	<u>81,966,740</u>
743								
744	594	Maintenance of Underground Lines						
745		DPW	S		28,989,233	7,107,330	31,042,303	7,588,671
746		DPW	SNPD		23,258	6,157	24,670	6,531
747				B2	<u>29,012,491</u>	<u>7,113,487</u>	<u>31,066,974</u>	<u>7,595,202</u>
748								
749	595	Maintenance of Line Transformers						
750		DPW	S		-	-	-	-
751		DPW	SNPD		1,101,111	291,493	1,165,061	308,422
752				B2	<u>1,101,111</u>	<u>291,493</u>	<u>1,165,061</u>	<u>308,422</u>
753								
754	596	Maint of Street Lighting & Signal Sys.						
755		DPW	S		1,868,303	689,285	1,995,782	734,147
756		DPW	SNPD		-	-	-	-
757				B2	<u>1,868,303</u>	<u>689,285</u>	<u>1,995,782</u>	<u>734,147</u>
758								
759	597	Maintenance of Meters						
760		DPW	S		691,372	214,424	733,787	227,348
761		DPW	SNPD		26,553	7,029	30,778	8,148
762				B2	<u>717,925</u>	<u>221,454</u>	<u>764,564</u>	<u>235,496</u>
763								
764	598	Maint of Misc. Distribution Plant						
765		DPW	S		1,430,122	(249,709)	1,547,816	(271,211)
766		DPW	SNPD		4,553,196	1,205,349	4,977,865	1,317,770
767				B2	<u>5,983,318</u>	<u>955,640</u>	<u>6,525,682</u>	<u>1,046,559</u>
768								
769		<b>Total Distribution Expense</b>		<b>B2</b>	<b><u>227,788,851</u></b>	<b><u>88,583,363</u></b>	<b><u>265,354,371</u></b>	<b><u>116,940,088</u></b>
770								
771								
772		Summary of Distribution Expense by Factor						
773		S			193,582,559	79,528,070	228,318,861	107,135,826
774		SNPD			34,206,291	9,055,294	37,035,510	9,804,261
775								
776		Total Distribution Expense by Factor			<u>227,788,851</u>	<u>88,583,363</u>	<u>265,354,371</u>	<u>116,940,088</u>
777								
778	901	Supervision						
779		CUST	S		615	-	678	-
780		CUST	CN		2,256,716	699,355	2,406,098	745,648
781				B2	<u>2,257,332</u>	<u>699,355</u>	<u>2,406,776</u>	<u>745,648</u>

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
782								
783	902	Meter Reading Expense						
784		CUST	S		12,882,743	2,311,692	13,743,678	2,480,518
785		CUST	CN		388,569	120,417	413,818	128,242
786				B2	<u>13,271,313</u>	<u>2,432,109</u>	<u>14,157,496</u>	<u>2,608,760</u>
787								
788	903	Customer Receipts & Collections						
789		CUST	S		3,369,238	765,765	3,600,953	813,440
790		CUST	CN		39,229,538	12,157,206	42,034,981	13,026,611
791				B2	<u>42,598,776</u>	<u>12,922,971</u>	<u>45,635,934</u>	<u>13,840,051</u>
792								
793	904	Uncollectible Accounts						
794		CUST	S		11,886,522	5,916,318	12,816,874	6,241,502
795		P	SG		-	-	-	-
796		CUST	CN		141,303	43,790	155,627	48,229
797				B2	<u>12,027,825</u>	<u>5,960,108</u>	<u>12,972,501</u>	<u>6,289,730</u>
798								
799	905	Misc. Customer Accounts Expense						
800		CUST	S		-	-	-	-
801		CUST	CN		25,493	7,900	28,077	8,701
802				B2	<u>25,493</u>	<u>7,900</u>	<u>28,077</u>	<u>8,701</u>
803								
804		<b>Total Customer Accounts Expense</b>		<b>B2</b>	<b><u>70,180,739</u></b>	<b><u>22,022,443</u></b>	<b><u>75,200,784</u></b>	<b><u>23,492,890</u></b>
805								
806		Summary of Customer Accts Exp by Factor						
807		S			28,139,119	8,993,775	30,162,183	9,535,460
808		CN			42,041,620	13,028,668	45,038,601	13,957,430
809		SG			-	-	-	-
810		<b>Total Customer Accounts Expense by Factor</b>			<b><u>70,180,739</u></b>	<b><u>22,022,443</u></b>	<b><u>75,200,784</u></b>	<b><u>23,492,890</u></b>
811								
812	907	Supervision						
813		CUST	S		-	-	-	-
814		CUST	CN		2,906	900	3,067	950
815				B2	<u>2,906</u>	<u>900</u>	<u>3,067</u>	<u>950</u>
816								
817	908	Customer Assistance						
818		CUST	S		109,367,868	3,471,925	119,297,876	3,710,056
819		CUST	CN		2,019,273	625,771	2,133,435	661,150
820								
821								
822				B2	<u>111,387,142</u>	<u>4,097,696</u>	<u>121,431,311</u>	<u>4,371,206</u>
823								
824	909	Informational & Instructional Adv						
825		CUST	S		1,954,258	679,790	2,231,821	793,001
826		CUST	CN		2,683,338	831,564	2,786,780	863,621
827				B2	<u>4,637,595</u>	<u>1,511,354</u>	<u>5,018,601</u>	<u>1,656,622</u>
828								
829	910	Misc. Customer Service						
830		CUST	S		-	-	-	-
831		CUST	CN		1,766	547	1,930	598
832								
833				B2	<u>1,766</u>	<u>547</u>	<u>1,930</u>	<u>598</u>
834								
835		<b>Total Customer Service Expense</b>		<b>B2</b>	<b><u>116,029,408</u></b>	<b><u>5,610,498</u></b>	<b><u>126,454,909</u></b>	<b><u>6,029,376</u></b>
836								
837								
838		Summary of Customer Service Exp by Factor						
839		S			111,322,126	4,151,715	121,529,697	4,503,056
840		CN			4,707,282	1,458,783	4,925,211	1,526,319
841								
842		<b>Total Customer Service Expense by Factor</b>		<b>B2</b>	<b><u>116,029,408</u></b>	<b><u>5,610,498</u></b>	<b><u>126,454,909</u></b>	<b><u>6,029,376</u></b>
843								
844								
845	911	Supervision						
846		CUST	S		-	-	-	-
847		CUST	CN		-	-	-	-
848				B2	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
849								
850	912	Demonstration & Selling Expense						
851		CUST	S		-	-	-	-
852		CUST	CN		-	-	-	-
853				B2	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
854								
855	913	Advertising Expense						
856		CUST	S		-	-	-	-
857		CUST	CN		-	-	-	-
858				B2	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
859								
860	916	Misc. Sales Expense						
861		CUST	S		-	-	-	-
862		CUST	CN		-	-	-	-
863				B2	-	-	-	-
864								
865		<b>Total Sales Expense</b>		<b>B2</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
866								
867								
868		Total Sales Expense by Factor						
869		S			-	-	-	-
870		CN			-	-	-	-
871		Total Sales Expense by Factor			-	-	-	-
872								
873		<b>Total Customer Service Exp Including Sales</b>		<b>B2</b>	<b>116,029,408</b>	<b>5,610,498</b>	<b>126,454,909</b>	<b>6,029,376</b>
874	920	Administrative & General Salaries						
875		PTD	S		2,285,428	702,610	2,405,442	739,506
876		CUST	CN		-	-	-	-
877		PTD	SO		76,467,813	20,778,661	80,666,662	21,919,618
878				B2	78,753,241	21,481,271	83,072,105	22,659,124
879								
880	921	Office Supplies & expenses						
881		PTD	S		2,345,814	1,810,997	2,518,313	1,944,169
882		CUST	CN		87,451	27,101	93,881	29,094
883		PTD	SO		8,230,193	2,236,397	10,141,692	2,755,810
884				B2	10,663,458	4,074,495	12,753,887	4,729,073
885								
886	922	A&G Expenses Transferred						
887		PTD	S		-	-	-	-
888		CUST	CN		-	-	-	-
889		PTD	SO		(37,446,530)	(10,175,376)	(39,576,424)	(10,754,134)
890				B2	(37,446,530)	(10,175,376)	(39,576,424)	(10,754,134)
891								
892	923	Outside Services						
893		PTD	S		1,045,345	229,797	1,091,542	239,952
894		CUST	CN		-	-	-	-
895		PTD	SO		22,722,700	6,174,458	23,726,885	6,447,326
896				B2	23,768,045	6,404,255	24,818,427	6,687,278
897								
898	924	Property Insurance						
899		PT	S		11,665,617	7,448,035	16,064,875	11,847,293
900		PT	SG		-	-	-	-
901		PTD	SO		4,371,510	1,187,874	3,612,548	981,641
902				B2	16,037,127	8,635,909	19,677,423	12,828,933
903								
904	925	Injuries & Damages						
905		PTD	S		1,484,743	1,484,743	1,608,709	1,608,709
906		PTD	SO		151,600,598	41,194,555	33,047,771	8,980,098
907				B2	153,085,341	42,679,298	34,656,480	10,588,807
908								
909	926	Employee Pensions & Benefits						
910		LABOR	S		5,664,605	163,978	6,023,258	174,360
911		CUST	CN		-	-	-	-
912		LABOR	SO		114,566,722	31,131,309	119,538,210	32,482,216
913				B2	120,231,327	31,295,287	125,561,468	32,656,576
914								
915	927	Franchise Requirements						
916		DMSC	S		-	-	-	-
917		DMSC	SO		-	-	-	-
918				B2	-	-	-	-
919								
920	928	Regulatory Commission Expense						
921		DMSC	S		18,139,814	5,799,002	19,310,225	6,019,755
922		P	SE		-	-	-	-
923		DMSC	SO		2,239,683	608,591	2,409,984	654,867
924		FERC	SG		4,289,878	1,118,386	4,628,933	1,206,779
925				B2	24,669,376	7,525,979	26,349,142	7,881,401
926								
927	929	Duplicate Charges						
928		LABOR	S		-	-	-	-
929		LABOR	SO		(124,736,799)	(33,894,833)	(125,385,193)	(34,071,021)
930				B2	(124,736,799)	(33,894,833)	(125,385,193)	(34,071,021)
931								
932	930	Misc General Expenses						
933		PTD	S		21,320	130	(1,647,450)	(1,669,716)
934		CUST	CN		-	-	-	-
935		P	SG		-	-	-	-
936		LABOR	SO		2,246,757	610,513	1,796,472	488,157
937				B2	2,268,077	610,643	149,022	(1,181,559)

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
938								
939	931	Rents						
940			PTD	S	1,032,000	454,841	1,113,828	490,906
941			PTD	SO	2,060,717	559,960	2,224,113	604,360
942				B2	3,092,716	1,014,801	3,337,941	1,095,266
943								
944	935	Maintenance of General Plant						
945			G	S	392,947	149,681	412,805	157,258
946			CUST	CN	27,697	8,583	29,091	9,015
947			G	SO	26,118,338	7,097,157	27,441,947	7,456,823
948				B2	26,538,982	7,255,422	27,883,842	7,623,096
949								
950		<b>Total Administrative &amp; General Expense</b>		<b>B2</b>	<b>296,924,361</b>	<b>86,907,150</b>	<b>193,298,120</b>	<b>60,742,837</b>
951								
952		Summary of A&G Expense by Factor						
953			S		44,077,632	18,243,813	48,901,547	21,552,190
954			SE		-	-	-	-
955			SO		248,441,702	67,509,267	139,644,667	37,945,760
956			SG		4,289,878	1,118,386	4,628,933	1,206,779
957			CN		115,148	35,684	122,972	38,109
958		Total A&G Expense by Factor			296,924,361	86,907,150	193,298,120	60,742,837
959								
960		<b>Total O&amp;M Expense</b>		<b>B2</b>	<b>3,081,999,779</b>	<b>803,402,344</b>	<b>3,226,372,050</b>	<b>861,542,561</b>
961	403SP	Steam Depreciation						
962			P	S	180,756,088	-	180,756,088	-
963			P	SG	40,420,413	10,537,740	40,420,413	10,537,740
964			P	SG	33,611,594	8,762,657	33,611,594	8,762,657
965			P	SG	223,954,796	58,385,781	364,113,614	94,925,664
966			P	SG	7,589,695	1,978,660	7,589,695	1,978,660
967				B3	486,332,585	79,664,838	626,491,403	116,204,721
968								
969	403NP	Nuclear Depreciation						
970			P	SG	-	-	-	-
971				B3	-	-	-	-
972								
973	403HP	Hydro Depreciation						
974			P	SG	(24,185,191)	(6,305,162)	(24,185,191)	(6,305,162)
975			P	SG	1,348,641	351,595	1,348,641	351,595
976			P	SG	46,696,890	12,174,039	48,954,211	12,762,530
977			P	SG	6,934,787	1,807,923	8,780,939	2,289,221
978			P	SG	-	-	-	-
979				B3	30,795,127	8,028,395	34,898,599	9,098,184
980								
981	403OP	Other Production Depreciation						
982			p	S	4,783	-	4,783	-
983			P	SG	-	-	-	-
984			P	SG	65,951,638	17,193,818	69,147,316	18,026,942
985			P	SG	3,697,797	964,028	3,697,797	964,028
986			P	SG	97,958,758	25,538,183	137,093,159	35,740,655
987				B3	167,612,977	43,696,029	209,943,056	54,731,626
988								
989	403TP	Transmission Depreciation						
990			T	SG	8,458,141	2,205,066	8,458,141	2,205,066
991			T	SG	10,613,292	2,766,921	10,613,292	2,766,921
992			T	SG	106,315,401	27,716,789	119,158,716	31,065,085
993				B3	125,386,834	32,688,776	138,230,148	36,037,072
994								
995								
996								
997	403	Distribution Depreciation						
998	360	Land & Land Rights	DPW	S	420,462	61,427	664,106	69,299
999	361	Structures	DPW	S	2,158,154	544,558	2,620,006	559,481
1000	362	Station Equipment	DPW	S	12,341,072	6,154,345	16,173,237	6,278,171
1001	363	Storage Battery Equip	DPW	S	-	-	-	-
1002	364	Poles & Towers	DPW	S	45,813,613	13,885,875	50,821,831	14,047,702
1003	365	OH Conductors	DPW	S	20,782,723	6,876,026	23,934,218	6,977,858
1004	366	UG Conduit	DPW	S	9,700,542	1,945,136	11,264,100	1,995,658
1005	367	UG Conductor	DPW	S	21,530,296	4,183,811	25,177,761	4,301,669
1006	368	Line Trans	DPW	S	35,711,989	11,543,624	41,233,042	11,722,022
1007	369	Services	DPW	S	20,733,655	6,967,771	24,147,742	7,078,088
1008	370	Meters	DPW	S	9,771,798	2,573,927	10,706,351	2,604,125
1009	371	Inst Cust Prem	DPW	S	478,452	121,725	510,764	122,769
1010	372	Leased Property	DPW	S	-	-	-	-
1011	373	Street Lighting	DPW	S	2,248,401	663,724	2,479,804	671,201
1012				B3	181,691,155	55,521,949	209,732,961	56,428,045



2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
1093	404HP	Amortization of Other Electric Plant						
1094		P	SG		311,696	81,260	311,696	81,260
1095		P	SG		-	-	-	-
1096		P	SG		-	-	-	-
1097				B4	311,696	81,260	311,696	81,260
1098								
1099	<b>Total Amortization of Limited Term Plant</b>			<b>B4</b>	<b>52,488,428</b>	<b>13,549,044</b>	<b>58,576,334</b>	<b>15,333,788</b>
1100								
1101								
1102	405	Amortization of Other Electric Plant						
1103		GP	S		-	-	-	-
1104								
1105				B4	-	-	-	-
1106								
1107	406	Amortization of Plant Acquisition Adj						
1108		P	S		301,635	-	301,635	-
1109		P	SG		-	-	-	-
1110		P	SG		-	-	-	-
1111		P	SG		6,496,204	1,693,583	1,789,996	466,658
1112		P	SO		-	-	-	-
1113				B4	6,797,839	1,693,583	2,091,631	466,658
1114	407	Amort of Prop Losses, Unrec Plant, etc						
1115		DPW	S		2,513,687	1,057,340	28,642,494	27,186,148
1116		GP	SO		-	-	-	-
1117		P	SG-P		-	-	-	-
1118		P	SE		-	-	-	-
1119		P	SG		23,824	6,211	961,656	250,707
1120		P	TROJP		-	-	-	-
1121				B4	2,537,511	1,063,551	29,604,150	27,436,855
1122								
1123	<b>Total Amortization Expense</b>			<b>B4</b>	<b>61,823,778</b>	<b>16,306,178</b>	<b>90,272,115</b>	<b>43,237,301</b>
1124								
1125								
1126								
1127	Summary of Amortization Expense by Factor							
1128		S			7,676,686	1,362,750	33,836,047	27,520,739
1129		SE			1,821	457	(12,865)	(3,225)
1130		TROJP			-	-	-	-
1131		DGP			-	-	-	-
1132		DGU			-	-	-	-
1133		SO			14,653,009	3,981,674	29,457,043	8,004,386
1134		SSGCT			-	-	-	-
1135		SSGCH			-	-	-	-
1136		CN			13,528,148	4,192,364	13,792,251	4,274,209
1137		SG			25,964,114	6,768,933	13,199,639	3,441,191
1138	Total Amortization Expense by Factor				61,823,778	16,306,178	90,272,115	43,237,301
1139	408	Taxes Other Than Income						
1140		DMSC	S		33,900,676	30,692,497	32,426,729	29,218,549
1141		GP	GPS		161,965,403	44,010,992	185,977,000	50,535,683
1142		GP	SO		13,226,755	3,594,117	13,226,755	3,594,117
1143		P	SE		871,530	218,476	871,530	218,476
1144		P	SG		2,232,349	581,981	2,320,579	604,983
1145		DMSC	OPRV-ID		-	-	-	-
1146		GP	EXCTAX		-	-	-	-
1147		GP	SG		-	-	-	-
1148								
1149								
1150								
1151	<b>Total Taxes Other Than Income</b>			<b>B5</b>	<b>212,196,714</b>	<b>79,098,063</b>	<b>234,822,593</b>	<b>84,171,808</b>
1152								
1153								
1154	41140	Deferred Investment Tax Credit - Fed						
1155		PTD	DGU		(1,703,368)	-	(1,055,733)	-
1156								
1157				B7	(1,703,368)	-	(1,055,733)	-
1158								
1159	41141	Deferred Investment Tax Credit - Idaho						
1160		PTD	DGU		-	-	-	-
1161								
1162				B7	-	-	-	-
1163								
1164	<b>Total Deferred ITC</b>			<b>B7</b>	<b>(1,703,368)</b>	<b>-</b>	<b>(1,055,733)</b>	<b>-</b>
1165								
1166								
1167	427	Interest on Long-Term Debt						
1168		GP	S		373,768,734	99,963,159	337,754,280	87,804,135
1169		GP	SNP		-	-	-	-
1170				B6	373,768,734	99,963,159	337,754,280	87,804,135

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
1171								
1172	428	Amortization of Debt Disc & Exp						
1173		GP	SNP		5,103,007	1,306,296	5,103,007	1,306,296
1174				B6	5,103,007	1,306,296	5,103,007	1,306,296
1175								
1176	429	Amortization of Premium on Debt						
1177		GP	SNP		(11,026)	(2,822)	(11,026)	(2,822)
1178				B6	(11,026)	(2,822)	(11,026)	(2,822)
1179								
1180	431	Other Interest Expense						
1181		NUTIL	OTH		-	-	-	-
1182		GP	SO		-	-	-	-
1183		GP	SNP		18,548,860	4,748,241	18,552,610	4,749,201
1184				B6	18,548,860	4,748,241	18,552,610	4,749,201
1185								
1186	432	AFUDC - Borrowed						
1187		GP	SNP		(38,314,971)	(9,808,081)	(38,314,971)	(9,808,081)
1188					(38,314,971)	(9,808,081)	(38,314,971)	(9,808,081)
1189								
1190		Total Elec. Interest Deductions for Tax		B6	359,094,605	96,206,794	323,083,901	84,048,729
1191								
1192		Non-Regulated Portion of Interest						
1193		427 NUTIL	NUTIL		-	-	-	-
1194		428 NUTIL	NUTIL		-	-	-	-
1195		429 NUTIL	NUTIL		-	-	-	-
1196		431 NUTIL	NUTIL		-	-	-	-
1197								
1198		Total Non-Regulated Interest			-	-	-	-
1199								
1200		Total Interest Deductions for Tax		B6	359,094,605	96,206,794	323,083,901	84,048,729
1201								
1202								
1203	419	Interest & Dividends						
1204		GP	S		-	-	-	-
1205		GP	SNP		(79,165,909)	(20,265,333)	(83,426,872)	(21,356,078)
1206		Total Operating Deductions for Tax		B6	(79,165,909)	(20,265,333)	(83,426,872)	(21,356,078)
1207								
1208								
1209	41010	Deferred Income Tax - Federal-DR						
1210		GP	S		309,752	186,017	(5,195,564)	404,694
1211		P	TROJD		-	-	-	-
1212		PT	SG		510,498	133,089	510,498	133,089
1213		LABOR	SO		(19,941,046)	(5,418,597)	6,619,626	1,798,756
1214		GP	SNP		28,884,552	7,394,029	29,009,377	7,425,983
1215		P	SE		(281,840)	(70,652)	37,622	9,431
1216		PT	SG		37,571,837	9,795,106	34,184,336	8,911,973
1217		GP	GPS		49,230,998	13,377,579	12,039,020	3,271,373
1218		DITEXP	DITEXP		-	-	-	-
1219		CUST	BADDEBT		-	-	-	-
1220		CUST	CN		-	-	-	-
1221		IBT	IBT		-	-	-	-
1222		DPW	CIAC		-	-	-	-
1223		GP	SCHMDEXP		-	-	-	-
1224		TAXDEPR	TAXDEPR		301,248,033	79,558,685	337,481,784	89,127,908
1225		DPW	SNPD		238,377	63,105	-	-
1226				B7	397,771,161	105,018,361	414,686,699	111,083,207
1227								
1228								
1229								
1230	41110	Deferred Income Tax - Federal-CR						
1231		GP	S		(181,173,017)	(60,241,301)	(131,453,332)	(20,437,298)
1232		P	SE		(9,598,996)	(2,406,289)	(4,161,684)	(1,043,257)
1233		PT	SG		(1,109,267)	(289,190)	(1,109,267)	(289,190)
1234		GP	SNP		(17,992,952)	(4,605,937)	(17,516,892)	(4,484,072)
1235		PT	SG		(680,477)	(177,403)	(579,991)	(151,206)
1236		GP	GPS		1,212,047	329,351	-	-
1237		LABOR	SO		(10,150,835)	(2,758,295)	(4,484,432)	(1,218,558)
1238		PT	SNPD		(937,677)	(248,227)	-	-
1239		CUST	BADDEBT		(873,780)	(423,653)	(0)	(0)
1240		P	SG		-	-	-	-
1241		DITEXP	SG		-	-	-	-
1242		P	TROJD		11,239	2,910	(1)	(0)
1243		IBT	CN		-	-	11,988	3,715
1244		DPW	CIAC		(29,968,119)	(7,933,339)	(21,049,481)	(5,572,344)
1245		GP	SCHMDEXP		(211,410,319)	(47,879,605)	(288,024,556)	(65,230,979)
1246		TAXDEPR	TAXDEPR		-	-	-	-
1247				B7	(462,672,154)	(126,630,979)	(468,367,647)	(98,423,188)
1248								
1249		Total Deferred Income Taxes		B7	(64,900,993)	(21,612,618)	(53,680,948)	12,660,019





2020 PROTOCOL					JUNE 2021		DECEMBER 2023	
Year End					UNADJUSTED RESULTS		NORMALIZED RESULTS	
ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
1330	Calculation of Taxable Income:							
1331	Operating Revenues				5,521,910,467	1,434,724,286	5,638,487,549	1,422,789,617
1332	Operating Deductions:							
1333	O & M Expenses				3,081,999,779	803,402,344	3,226,372,050	861,542,561
1334	Depreciation Expense				1,035,081,277	232,580,644	1,271,626,317	287,994,295
1335	Amortization Expense				61,823,778	16,306,178	90,272,115	43,237,301
1336	Taxes Other Than Income				212,196,714	79,098,063	234,822,593	84,171,808
1337	Interest & Dividends (AFUDC-Equity)				(79,165,909)	(20,265,333)	(83,426,872)	(21,356,078)
1338	Misc Revenue & Expense				(1,733,836)	(99,173)	(1,503,560)	3,165
1339	Total Operating Deductions				4,310,201,804	1,111,022,723	4,738,162,643	1,255,593,052
1340	Other Deductions:							
1341	Interest Deductions				359,094,605	96,206,794	323,083,901	84,048,729
1342	Interest on PCRBS				-	-	-	-
1343	Schedule M Adjustments				(362,919,488)	(22,542,453)	(366,091,959)	(118,725,149)
1344								
1345	Income Before State Taxes				489,694,569	204,952,316	211,149,047	(35,577,313)
1346								
1347	State Income Taxes				26,781,277	9,304,835	30,934,209	4,230,426
1348								
1349	Total Taxable Income				462,913,292	195,647,481	180,214,838	(39,807,739)
1350								
1351	Tax Rate				21.0%	21.0%	21.0%	21.0%
1352								
1353	Federal Income Tax - Calculated				97,211,791	41,085,971	37,845,116	(8,359,625)
1354								
1355	Adjustments to Calculated Tax:							
1356	40910	P	SE		(45,220)	(11,336)	(17,000)	(4,262)
1357	40910	PTC	SG		(125,906,829)	(32,824,341)	(203,036,306)	(52,932,259)
1358	40910	P	SO		(1,659)	(451)	-	-
1359	40910	IRS Settle	LABOR	S	-	-	-	-
1360	Federal Income Tax Expense				(28,741,917)	8,249,843	(165,208,190)	(61,296,146)
1361								
1362	Total Operating Expenses				4,320,802,712	1,127,230,117	4,632,578,853	1,232,543,429
1363	310	Land and Land Rights						
1364		P	SG		2,327,033	606,665	2,327,033	606,665
1365		P	SG		33,837,468	8,821,544	33,837,468	8,821,544
1366		P	SG		54,188,889	14,127,229	54,188,889	14,127,229
1367		P	S		-	-	-	-
1368		P	SG		1,266,851	330,272	1,266,851	330,272
1369				B8	91,620,242	23,885,710	91,620,242	23,885,710
1370								
1371	311	Structures and Improvements						
1372		P	SG		226,302,042	58,997,716	226,302,042	58,997,716
1373		P	SG		313,179,657	81,647,008	313,179,657	81,647,008
1374		P	SG		458,329,586	119,488,091	458,329,586	119,488,091
1375		P	SG		-	-	-	-
1376				B8	997,811,285	260,132,815	997,811,285	260,132,815
1377								
1378	312	Boiler Plant Equipment						
1379		P	SG		586,722,706	152,960,616	586,722,706	152,960,616
1380		P	SG		464,967,271	121,218,558	464,967,271	121,218,558
1381		P	SG		3,285,513,183	856,544,524	3,347,065,168	872,591,337
1382		P	SG		-	-	-	-
1383				B8	4,337,203,161	1,130,723,698	4,398,755,145	1,146,770,511
1384								
1385	314	Turbogenerator Units						
1386		P	SG		109,027,524	28,423,848	109,027,524	28,423,848
1387		P	SG		109,153,256	28,456,627	109,153,256	28,456,627
1388		P	SG		727,390,873	189,633,289	727,390,873	189,633,289
1389		P	SG		-	-	-	-
1390				B8	945,571,653	246,513,764	945,571,653	246,513,764
1391								
1392	315	Accessory Electric Equipment						
1393		P	SG		85,763,790	22,358,913	85,763,790	22,358,913
1394		P	SG		133,124,041	34,705,893	133,124,041	34,705,893
1395		P	SG		204,707,307	53,367,895	204,707,307	53,367,895
1396		P	SG		-	-	-	-
1397				B8	423,595,138	110,432,701	423,595,138	110,432,701
1398								
1399								
1400								
1401	316	Misc Power Plant Equipment						
1402		P	SG		2,348,343	612,221	2,348,343	612,221
1403		P	SG		4,912,823	1,280,790	4,912,823	1,280,790
1404		P	SG		23,737,398	6,188,421	23,737,398	6,188,421
1405		P	SG		-	-	-	-
1406				B8	30,998,565	8,081,432	30,998,565	8,081,432

2020 PROTOCOL					JUNE 2021		DECEMBER 2023	
Year End					UNADJUSTED RESULTS		NORMALIZED RESULTS	
ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
1407								
1408	317	Steam Plant ARO						
1409		P	S		-	-	-	-
1410				B8	-	-	-	-
1411								
1412	SP	Unclassified Steam Plant - Account 300						
1413		P	SG		57,225,129	14,918,787	57,225,129	14,918,787
1414				B8	57,225,129	14,918,787	57,225,129	14,918,787
1415								
1416								
1417		<b>Total Steam Production Plant</b>		B8	<b>6,884,025,173</b>	<b>1,794,688,908</b>	<b>6,945,577,158</b>	<b>1,810,735,721</b>
1418								
1419								
1420		Summary of Steam Production Plant by Factor						
1421		S			-	-	-	-
1422		DGP			-	-	-	-
1423		DGU			-	-	-	-
1424		SG			6,884,025,173	1,794,688,908	6,945,577,158	1,810,735,721
1425		SSGCH			-	-	-	-
1426		Total Steam Production Plant by Factor			6,884,025,173	1,794,688,908	6,945,577,158	1,810,735,721
1427	320	Land and Land Rights						
1428		P	SG		-	-	-	-
1429		P	SG		-	-	-	-
1430				B8	-	-	-	-
1431								
1432	321	Structures and Improvements						
1433		P	SG		-	-	-	-
1434		P	SG	B8	-	-	-	-
1435					-	-	-	-
1436								
1437	322	Reactor Plant Equipment						
1438		P	SG		-	-	-	-
1439		P	SG		-	-	-	-
1440				B8	-	-	-	-
1441								
1442	323	Turbogenerator Units						
1443		P	SG		-	-	-	-
1444		P	SG		-	-	-	-
1445				B8	-	-	-	-
1446								
1447	324	Land and Land Rights						
1448		P	SG		-	-	-	-
1449		P	SG		-	-	-	-
1450				B8	-	-	-	-
1451								
1452	325	Misc. Power Plant Equipment						
1453		P	SG		-	-	-	-
1454		P	SG		-	-	-	-
1455				B8	-	-	-	-
1456								
1457								
1458	NP	Unclassified Nuclear Plant - Acct 300						
1459		P	SG		-	-	-	-
1460				B8	-	-	-	-
1461								
1462								
1463		<b>Total Nuclear Production Plant</b>		B8	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
1464								
1465								
1466								
1467		Summary of Nuclear Production Plant by Factor						
1468		DGP			-	-	-	-
1469		DGU			-	-	-	-
1470		SG			-	-	-	-
1471								
1472		Total Nuclear Plant by Factor			-	-	-	-
1473								
1474	330	Land and Land Rights						
1475		P	SG		10,332,372	2,693,685	10,332,372	2,693,685
1476		P	SG		5,268,322	1,373,470	5,268,322	1,373,470
1477		P	SG		21,965,016	5,726,355	21,965,016	5,726,355
1478		P	SG		1,316,755	343,282	1,316,755	343,282
1479				B8	38,882,464	10,136,791	38,882,464	10,136,791
1480								
1481	331	Structures and Improvements						
1482		P	SG		19,409,410	5,060,100	19,409,410	5,060,100
1483		P	SG		4,846,938	1,263,613	4,846,938	1,263,613
1484		P	SG		249,777,261	65,117,786	249,777,261	65,117,786
1485		P	SG		14,334,530	3,737,061	14,334,530	3,737,061
1486				B8	288,368,139	75,178,560	288,368,139	75,178,560

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
1487								
1488	332	Reservoirs, Dams & Waterways						
1489		P	SG		145,182,405	37,849,549	145,182,405	37,849,549
1490		P	SG		18,775,808	4,894,917	18,775,808	4,894,917
1491		P	SG		288,307,285	75,162,695	371,491,566	96,849,122
1492		P	SG		80,130,008	20,890,167	109,928,384	28,658,706
1493		0	SG		-	-	-	-
1494				B8	532,395,506	138,797,329	645,378,163	168,252,294
1495								
1496	333	Water Wheel, Turbines, & Generators						
1497		P	SG		28,717,970	7,486,873	28,717,970	7,486,873
1498		P	SG		6,749,763	1,759,686	6,749,763	1,759,686
1499		P	SG		67,204,973	17,520,566	67,204,973	17,520,566
1500		P	SG		43,566,039	11,357,815	43,566,039	11,357,815
1501				B8	146,238,745	38,124,941	146,238,745	38,124,941
1502								
1503	334	Accessory Electric Equipment						
1504		P	SG		3,653,216	952,406	3,653,216	952,406
1505		P	SG		3,335,903	869,681	3,335,903	869,681
1506		P	SG		67,845,688	17,687,603	67,845,688	17,687,603
1507		P	SG		11,197,573	2,919,246	11,197,573	2,919,246
1508				B8	86,032,381	22,428,936	86,032,381	22,428,936
1509								
1510								
1511								
1512	335	Misc. Power Plant Equipment						
1513		P	SG		1,129,697	294,516	1,129,697	294,516
1514		P	SG		153,991	40,146	153,991	40,146
1515		P	SG		1,261,938	328,991	1,261,938	328,991
1516		P	SG		18,279	4,765	18,279	4,765
1517				B8	2,563,904	668,419	2,563,904	668,419
1518								
1519	336	Roads, Railroads & Bridges						
1520		P	SG		4,363,451	1,137,566	4,363,451	1,137,566
1521		P	SG		734,401	191,461	734,401	191,461
1522		P	SG		18,843,685	4,912,613	18,843,685	4,912,613
1523		P	SG		2,333,429	608,333	2,333,429	608,333
1524				B8	26,274,965	6,849,973	26,274,965	6,849,973
1525								
1526	337	Hydro Plant ARO						
1527		P	S		-	-	-	-
1528				B8	-	-	-	-
1529								
1530	HP	Unclassified Hydro Plant - Acct 300						
1531		P	S		-	-	-	-
1532		P	SG		-	-	-	-
1533		P	SG		-	-	-	-
1534		P	SG		-	-	-	-
1535				B8	-	-	-	-
1536								
1537		<b>Total Hydraulic Production Plant</b>		B8	<b>1,120,756,105</b>	<b>292,184,950</b>	<b>1,233,738,762</b>	<b>321,639,915</b>
1538								
1539		Summary of Hydraulic Plant by Factor						
1540		S			-	-	-	-
1541		SG			1,120,756,105	292,184,950	1,233,738,762	321,639,915
1542		DGP			-	-	-	-
1543		DGU			-	-	-	-
1544		<b>Total Hydraulic Plant by Factor</b>			<b>1,120,756,105</b>	<b>292,184,950</b>	<b>1,233,738,762</b>	<b>321,639,915</b>
1545								
1546	340	Land and Land Rights						
1547		P	S		74,986	74,986	74,986	74,986
1548		P	SG		39,022,504	10,173,300	39,022,504	10,173,300
1549		P	SG		11,778,739	3,070,758	11,778,739	3,070,758
1550		P	SG		235,129	61,299	235,129	61,299
1551				B8	51,111,358	13,380,343	51,111,358	13,380,343
1552								
1553	341	Structures and Improvements						
1554			S		57,276	-	57,276	-
1555		P	SG		170,259,946	44,387,350	166,781,694	43,480,558
1556		P	SG		-	-	-	-
1557		P	SG		95,644,873	24,934,945	95,644,873	24,934,945
1558		P	SG		4,273,000	1,113,986	4,273,000	1,113,986
1559				B8	270,235,094	70,436,281	266,756,842	69,529,489
1560								
1561	342	Fuel Holders, Producers & Accessories						
1562		P	SG		13,623,206	3,551,616	13,623,206	3,551,616
1563		P	SG		-	-	-	-
1564		P	SG		2,759,334	719,368	2,759,334	719,368
1565				B8	16,382,540	4,270,984	16,382,540	4,270,984



2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
1647	355	Poles and Fixtures						
1648		T	SG		59,871,353	15,608,667	59,871,353	15,608,667
1649		T	SG		113,621,585	29,621,536	113,621,585	29,621,536
1650		T	SG		935,765,327	243,957,221	1,243,846,459	324,275,026
1651				B8	1,109,258,265	289,187,424	1,417,339,397	369,505,228
1652								
1653	356	Clearing and Grading						
1654		T	SG		157,481,552	41,055,979	157,481,552	41,055,979
1655		T	SG		157,154,432	40,970,698	157,154,432	40,970,698
1656		T	SG		1,064,442,587	277,503,823	1,064,442,587	277,503,823
1657				B8	1,379,078,572	359,530,500	1,379,078,572	359,530,500
1658								
1659	357	Underground Conduit						
1660		T	SG		6,371	1,661	6,371	1,661
1661		T	SG		91,651	23,894	91,651	23,894
1662		T	SG		3,759,944	980,230	3,759,944	980,230
1663				B8	3,857,965	1,005,785	3,857,965	1,005,785
1664								
1665	358	Underground Conductors						
1666		T	SG		-	-	-	-
1667		T	SG		1,087,552	283,529	1,087,552	283,529
1668		T	SG		7,993,065	2,083,819	7,993,065	2,083,819
1669				B8	9,080,617	2,367,348	9,080,617	2,367,348
1670								
1671	359	Roads and Trails						
1672		T	SG		1,863,032	485,699	1,863,032	485,699
1673		T	SG		440,513	114,843	440,513	114,843
1674		T	SG		9,842,468	2,565,965	9,842,468	2,565,965
1675				B8	12,146,013	3,166,507	12,146,013	3,166,507
1676								
1677	TP	Unclassified Trans Plant - Acct 300						
1678		T	SG		924,562,138	241,036,512	924,562,138	241,036,512
1679				B8	924,562,138	241,036,512	924,562,138	241,036,512
1680								
1681	TS0	Unclassified Trans Sub Plant - Acct 300						
1682		T	SG		-	-	-	-
1683				B8	-	-	-	-
1684								
1685	B8	<b>Total Transmission Plant</b>			<b>7,736,004,378</b>	<b>2,016,802,800</b>	<b>8,043,847,692</b>	<b>2,097,058,605</b>
1686		Summary of Transmission Plant by Factor						
1687		DGP			-	-	-	-
1688		DGU			-	-	-	-
1689		SG			7,736,004,378	2,016,802,800	8,043,847,692	2,097,058,605
1690		Total Transmission Plant by Factor			7,736,004,378	2,016,802,800	8,043,847,692	2,097,058,605
1691	360	Land and Land Rights						
1692		DPW	S		66,395,110	14,306,812	71,858,475	15,341,593
1693				B8	66,395,110	14,306,812	71,858,475	15,341,593
1694								
1695	361	Structures and Improvements						
1696		DPW	S		125,858,575	32,761,372	136,094,930	34,602,903
1697				B8	125,858,575	32,761,372	136,094,930	34,602,903
1698								
1699	362	Station Equipment						
1700		DPW	S		1,044,297,304	262,150,735	1,130,227,989	278,426,317
1701				B8	1,044,297,304	262,150,735	1,130,227,989	278,426,317
1702								
1703	363	Storage Battery Equipment						
1704		DPW	S		-	-	-	-
1705				B8	-	-	-	-
1706								
1707	364	Poles, Towers & Fixtures						
1708		DPW	S		1,364,781,739	452,281,633	1,477,083,695	473,552,029
1709				B8	1,364,781,739	452,281,633	1,477,083,695	473,552,029
1710								
1711	365	Overhead Conductors						
1712		DPW	S		858,809,016	299,985,292	929,476,676	313,370,002
1713				B8	858,809,016	299,985,292	929,476,676	313,370,002
1714								
1715	366	Underground Conduit						
1716		DPW	S		426,082,888	106,676,187	461,143,396	113,316,773
1717				B8	426,082,888	106,676,187	461,143,396	113,316,773
1718								
1719								
1720								
1721								
1722	367	Underground Conductors						
1723		DPW	S		993,965,104	208,212,087	1,075,754,171	223,703,231
1724				B8	993,965,104	208,212,087	1,075,754,171	223,703,231

2020 PROTOCOL				JUNE 2021				DECEMBER 2023			
Year End				UNADJUSTED RESULTS				NORMALIZED RESULTS			
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON	TOTAL	OREGON	
ACCT		FUNC									
1725											
1726	368	Line Transformers									
1727		DPW	S		1,504,533,721	498,477,508	1,628,335,259	521,925,966			
1728				B8	1,504,533,721	498,477,508	1,628,335,259	521,925,966			
1729											
1730	369	Services									
1731		DPW	S		930,367,417	325,742,456	1,006,923,307	340,242,418			
1732				B8	930,367,417	325,742,456	1,006,923,307	340,242,418			
1733											
1734	370	Meters									
1735		DPW	S		254,673,505	97,716,304	275,629,480	101,685,442			
1736				B8	254,673,505	97,716,304	275,629,480	101,685,442			
1737											
1738	371	Installations on Customers' Premises									
1739		DPW	S		8,805,282	2,666,274	9,529,830	2,803,506			
1740				B8	8,805,282	2,666,274	9,529,830	2,803,506			
1741											
1742	372	Leased Property									
1743		DPW	S		-	-	-	-			
1744				B8	-	-	-	-			
1745											
1746	373	Street Lights									
1747		DPW	S		63,059,406	24,884,170	68,248,290	25,866,963			
1748				B8	63,059,406	24,884,170	68,248,290	25,866,963			
1749											
1750	DP	Unclassified Dist Plant - Acct 300									
1751		DPW	S		161,745,166	39,370,985	161,745,166	39,370,985			
1752				B8	161,745,166	39,370,985	161,745,166	39,370,985			
1753											
1754	DS0	Unclassified Dist Sub Plant - Acct 300									
1755		DPW	S		-	-	-	-			
1756				B8	-	-	-	-			
1757											
1758											
1759		<b>Total Distribution Plant</b>		<b>B8</b>	<b>7,803,374,232</b>	<b>2,365,231,816</b>	<b>8,432,050,664</b>	<b>2,484,208,127</b>			
1760											
1761		Summary of Distribution Plant by Factor									
1762		S			7,803,374,232	2,365,231,816	8,432,050,664	2,484,208,127			
1763											
1764		Total Distribution Plant by Factor			7,803,374,232	2,365,231,816	8,432,050,664	2,484,208,127			
1765	389	Land and Land Rights									
1766		G-SITUS	S		15,079,558	6,116,556	15,079,558	6,116,556			
1767		CUST	CN		1,128,506	349,723	1,128,506	349,723			
1768		G-DGU	SG		332	87	332	87			
1769		G-SG	SG		1,228	320	1,228	320			
1770		PTD	SO		7,611,617	2,068,311	7,611,617	2,068,311			
1771				B8	23,821,241	8,534,997	23,821,241	8,534,997			
1772											
1773	390	Structures and Improvements									
1774		G-SITUS	S		137,788,608	40,901,786	137,788,608	40,901,786			
1775		G-DGP	SG		335,238	87,398	335,238	87,398			
1776		G-DGU	SG		1,356,387	353,615	1,356,387	353,615			
1777		CUST	CN		8,207,715	2,543,565	8,207,715	2,543,565			
1778		G-SG	SG		10,392,416	2,709,338	10,392,416	2,709,338			
1779		P	SE		888,035	222,614	888,035	222,614			
1780		PTD	SO		101,391,609	27,551,225	101,391,609	27,551,225			
1781				B8	260,360,008	74,369,541	260,360,008	74,369,541			
1782											
1783	391	Office Furniture & Equipment									
1784		G-SITUS	S		7,401,451	2,404,388	7,401,451	2,404,388			
1785		G-DGP	SG		-	-	-	-			
1786		G-DGU	SG		-	-	-	-			
1787		CUST	CN		4,028,345	1,248,381	4,028,345	1,248,381			
1788		G-SG	SG		4,114,866	1,072,760	4,114,866	1,072,760			
1789		P	SE		31,954	8,010	31,954	8,010			
1790		PTD	SO		60,767,447	16,512,388	60,767,447	16,512,388			
1791		G-SG	SG		-	-	-	-			
1792		G-SG	SG		4,039	1,053	4,039	1,053			
1793				B8	76,348,102	21,246,980	76,348,102	21,246,980			

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
1794								
1795	392	Transportation Equipment						
1796		G-SITUS	S		101,190,413	26,003,370	101,190,413	26,003,370
1797		PTD	SO		7,764,904	2,109,964	7,764,904	2,109,964
1798		G-SG	SG		23,530,085	6,134,374	23,530,085	6,134,374
1799		CUST	CN		-	-	-	-
1800		G-DGU	SG		401,191	104,592	401,191	104,592
1801		P	SE		327,360	82,063	327,360	82,063
1802		G-DGP	SG		70,616	18,410	70,616	18,410
1803		G-SG	SG		-	-	-	-
1804		G-DGU	SG		44,655	11,642	44,655	11,642
1805				B8	133,329,224	34,464,413	133,329,224	34,464,413
1806								
1807	393	Stores Equipment						
1808		G-SITUS	S		9,087,544	2,735,814	9,087,544	2,735,814
1809		G-DGP	SG		-	-	-	-
1810		G-DGU	SG		-	-	-	-
1811		PTD	SO		248,585	67,548	248,585	67,548
1812		G-SG	SG		6,008,319	1,566,389	6,008,319	1,566,389
1813		G-DGU	SG		53,971	14,070	53,971	14,070
1814				B8	15,398,418	4,383,821	15,398,418	4,383,821
1815								
1816	394	Tools, Shop & Garage Equipment						
1817		G-SITUS	S		36,331,376	10,914,668	36,331,376	10,914,668
1818		G-DGP	SG		37,684	9,824	37,684	9,824
1819		G-SG	SG		21,689,441	5,654,511	21,689,441	5,654,511
1820		PTD	SO		1,959,768	532,529	1,959,768	532,529
1821		P	SE		125,691	31,508	125,691	31,508
1822		G-DGU	SG		-	-	-	-
1823		G-SG	SG		-	-	-	-
1824		G-SG	SG		89,913	23,441	89,913	23,441
1825				B8	60,233,874	17,166,482	60,233,874	17,166,482
1826								
1827	395	Laboratory Equipment						
1828		G-SITUS	S		23,539,739	9,565,368	23,539,739	9,565,368
1829		G-DGP	SG		-	-	-	-
1830		G-DGU	SG		-	-	-	-
1831		PTD	SO		4,872,934	1,324,126	4,872,934	1,324,126
1832		P	SE		1,343,231	336,723	1,343,231	336,723
1833		G-SG	SG		6,447,642	1,680,922	6,447,642	1,680,922
1834		G-SG	SG		-	-	-	-
1835		G-SG	SG		14,022	3,655	14,022	3,655
1836				B8	36,217,568	12,910,795	36,217,568	12,910,795
1837								
1838	396	Power Operated Equipment						
1839		G-SITUS	S		154,961,157	44,851,927	154,961,157	44,851,927
1840		G-DGP	SG		262,000	68,304	262,000	68,304
1841		G-SG	SG		45,162,242	11,773,951	45,162,242	11,773,951
1842		PTD	SO		8,335,763	2,265,084	8,335,763	2,265,084
1843		G-DGU	SG		924,826	241,105	924,826	241,105
1844		P	SE		236,686	59,333	236,686	59,333
1845		P	SG		-	-	-	-
1846		G-SG	SG		-	-	-	-
1847				B8	209,882,674	59,259,704	209,882,674	59,259,704
1848	397	Communication Equipment						
1849		G-SITUS	S		201,031,280	80,037,895	272,972,646	99,466,592
1850		G-DGP	SG		301,777	78,674	301,777	78,674
1851		G-DGU	SG		139,259	36,305	139,259	36,305
1852		PTD	SO		94,039,446	25,553,416	149,911,488	40,735,572
1853		CUST	CN		3,848,526	1,192,655	2,058,814	638,025
1854		G-SG	SG		182,194,294	47,498,676	190,670,129	49,708,355
1855		P	SE		361,776	90,690	93,619	23,469
1856		G-SG	SG		-	-	-	-
1857		G-SG	SG		16,633	4,336	16,633	4,336
1858				B8	481,932,990	154,492,648	616,164,365	190,691,327
1859								
1860	398	Misc. Equipment						
1861		G-SITUS	S		3,167,859	1,225,125	3,167,859	1,225,125
1862		G-DGP	SG		-	-	-	-
1863		G-DGU	SG		-	-	-	-
1864		CUST	CN		82,497	25,566	82,497	25,566
1865		PTD	SO		2,228,810	605,636	2,228,810	605,636
1866		P	SE		3,966	994	3,966	994
1867		G-SG	SG		2,872,099	748,766	2,872,099	748,766
1868		G-SG	SG		-	-	-	-
1869				B8	8,355,230	2,606,087	8,355,230	2,606,087



2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
1870								
1871	399	Coal Mine						
1872		P	SE		1,822,901	456,967	50,741,701	12,719,998
1873	MP	P	SE		-	-	-	-
1874				B8	<u>1,822,901</u>	<u>456,967</u>	<u>50,741,701</u>	<u>12,719,998</u>
1875								
1876	399L	WIDCO Capital Lease						
1877		P	SE		-	-	-	-
1878					-	-	-	-
1879					-	-	-	-
1880		Remove Capital Leases			-	-	-	-
1881					-	-	-	-
1882					-	-	-	-
1883	1011390	General Capital Leases						
1884		G-SITUS	S		4,168,467	1,612,664	4,168,467	1,612,664
1885		P	SG		9,880,847	2,575,971	9,880,847	2,575,971
1886		PTD	SO		-	-	-	-
1887				B9	<u>14,049,314</u>	<u>4,188,634</u>	<u>14,049,314</u>	<u>4,188,634</u>
1888								
1889		Remove Capital Leases			<u>(14,049,314)</u>	<u>(4,188,634)</u>	<u>(14,049,314)</u>	<u>(4,188,634)</u>
1890					-	-	-	-
1891					-	-	-	-
1892	1011346	General Gas Line Capital Leases						
1893		P	SG		-	-	-	-
1894				B9	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
1895								
1896		Remove Capital Leases			-	-	-	-
1897					-	-	-	-
1898					-	-	-	-
1899	GP	Unclassified Gen Plant - Acct 300						
1900		G-SITUS	S		-	-	-	-
1901		PTD	SO		61,631,793	16,747,258	61,631,793	16,747,258
1902		CUST	CN		-	-	-	-
1903		G-SG	SG		-	-	-	-
1904		G-DGP	SG		-	-	-	-
1905		G-DGU	SG		-	-	-	-
1906				B8	<u>61,631,793</u>	<u>16,747,258</u>	<u>61,631,793</u>	<u>16,747,258</u>
1907								
1908	399G	Unclassified Gen Plant - Acct 300						
1909		G-SITUS	S		-	-	-	-
1910		PTD	SO		-	-	-	-
1911		G-SG	SG		-	-	-	-
1912		G-DGP	SG		-	-	-	-
1913		G-DGU	SG		-	-	-	-
1914				B8	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
1915								
1916		<b>Total General Plant</b>		<b>B8</b>	<b><u>1,369,334,022</u></b>	<b><u>406,639,694</u></b>	<b><u>1,552,484,198</u></b>	<b><u>455,101,404</u></b>
1917								
1918		Summary of General Plant by Factor						
1919		S			693,747,452	226,369,560	765,688,819	245,798,256
1920		DGP			-	-	-	-
1921		DGU			-	-	-	-
1922		SG			316,346,020	82,472,489	324,821,855	84,682,168
1923		SO			350,852,677	95,337,485	406,724,719	110,519,641
1924		SE			5,141,598	1,288,903	53,792,243	13,484,712
1925		CN			17,295,589	5,359,891	15,505,877	4,805,260
1926		DEU			-	-	-	-
1927		SSGCT			-	-	-	-
1928		SSGCH			-	-	-	-
1929		Less Capital Leases			<u>(14,049,314)</u>	<u>(4,188,634)</u>	<u>(14,049,314)</u>	<u>(4,188,634)</u>
1930		<b>Total General Plant by Factor</b>			<b><u>1,369,334,022</u></b>	<b><u>406,639,694</u></b>	<b><u>1,552,484,198</u></b>	<b><u>455,101,404</u></b>
1931	301	Organization						
1932		I-SITUS	S		-	-	-	-
1933		PTD	SO		-	-	-	-
1934		I-SG	SG		-	-	-	-
1935				B8	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
1936	302	Franchise & Consent						
1937		I-SITUS	S		(31,081,215)	-	(31,081,215)	-
1938		I-SG	SG		13,159,840	3,430,815	12,027,142	3,135,517
1939		I-SG	SG		177,566,825	46,292,279	177,482,844	46,270,384
1940		I-SG	SG		10,014,897	2,610,918	9,746,329	2,540,901
1941		I-DGP	SG		-	-	-	-
1942		I-DGU	SG		477,596	124,511	477,596	124,511
1943				B8	<u>170,137,943</u>	<u>52,458,523</u>	<u>168,652,697</u>	<u>52,071,314</u>

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
1944								
1945	303	Miscellaneous Intangible Plant						
1946		I-SITUS	S		22,092,897	4,616,002	21,935,586	4,609,463
1947		I-SG	SG		197,523,407	51,495,028	197,523,407	51,495,028
1948		PTD	SO		432,009,413	117,390,272	476,788,634	129,558,166
1949		P	SE		9,106	2,283	(64,323)	(16,125)
1950		CUST	CN		214,248,773	66,395,542	213,633,287	66,204,803
1951		P	SG		-	-	-	-
1952		I-DGP	SG		-	-	-	-
1953				B8	<u>865,883,596</u>	<u>239,899,126</u>	<u>909,816,590</u>	<u>251,851,335</u>
1954	303	Less Non-Regulated Plant						
1955		I-SITUS	S		-	-	-	-
1956					<u>865,883,596</u>	<u>239,899,126</u>	<u>909,816,590</u>	<u>251,851,335</u>
1957	IP	Unclassified Intangible Plant - Acct 300						
1958		I-SITUS	S		-	-	-	-
1959		I-SG	SG		-	-	-	-
1960		I-DGU	SG		-	-	-	-
1961		PTD	SO		-	-	-	-
1962					-	-	-	-
1963					-	-	-	-
1964		<b>Total Intangible Plant</b>		B8	<u><b>1,036,021,539</b></u>	<u><b>292,357,649</b></u>	<u><b>1,078,469,287</b></u>	<u><b>303,922,649</b></u>
1965								
1966		Summary of Intangible Plant by Factor						
1967		S			(8,988,318)	4,616,002	(9,145,629)	4,609,463
1968		DGP			-	-	-	-
1969		DGU			-	-	-	-
1970		SG			398,742,565	103,953,550	397,257,319	103,566,342
1971		SO			432,009,413	117,390,272	476,788,634	129,558,166
1972		CN			214,248,773	66,395,542	213,633,287	66,204,803
1973		SSGCT			-	-	-	-
1974		SSGCH			-	-	-	-
1975		SE			9,106	2,283	(64,323)	(16,125)
1976		<b>Total Intangible Plant by Factor</b>			<u>1,036,021,539</u>	<u>292,357,649</u>	<u>1,078,469,287</u>	<u>303,922,649</u>
1977		Summary of Unclassified Plant (Account 106)						
1978		DP			161,745,166	39,370,985	161,745,166	39,370,985
1979		DSO			-	-	-	-
1980		GP			61,631,793	16,747,258	61,631,793	16,747,258
1981		HP			-	-	-	-
1982		NP			-	-	-	-
1983		OP			(553,173)	(144,214)	(553,173)	(144,214)
1984		TP			924,562,138	241,036,512	924,562,138	241,036,512
1985		TSO			-	-	-	-
1986		IP			-	-	-	-
1987		MP			-	-	-	-
1988		SP			57,225,129	14,918,787	57,225,129	14,918,787
1989		<b>Total Unclassified Plant by Factor</b>			<u>1,204,611,053</u>	<u>311,929,327</u>	<u>1,204,611,053</u>	<u>311,929,327</u>
1990								
1991		<b>Total Electric Plant in Service</b>		B8	<u><b>31,317,729,025</b></u>	<u><b>8,567,379,441</b></u>	<u><b>32,579,238,234</b></u>	<u><b>8,852,783,093</b></u>
1992		Summary of Electric Plant by Factor						
1993		S			8,488,566,813	2,596,292,363	9,189,342,617	2,735,006,147
1994		SE			5,150,704	1,291,185	53,727,919	13,468,587
1995		DGU			-	-	-	-
1996		DGP			-	-	-	-
1997		SG			21,823,654,370	5,689,501,337	22,237,564,495	5,797,409,122
1998		SO			782,862,090	212,727,757	883,513,353	240,077,807
1999		CN			231,544,362	71,755,433	229,139,163	71,010,064
2000		DEU			-	-	-	-
2001		SSGCH			-	-	-	-
2002		SSGCT			-	-	-	-
2003		Less Capital Leases			(14,049,314)	(4,188,634)	(14,049,314)	(4,188,634)
2004					<u>31,317,729,025</u>	<u>8,567,379,441</u>	<u>32,579,238,234</u>	<u>8,852,783,093</u>
2005	105	Plant Held For Future Use						
2006		DPW	S		13,293,032	6,893,577	-	-
2007		P	SG		-	-	-	-
2008		T	SG		1,679,914	437,959	1,679,914	437,959
2009		P	SG		8,923,302	2,326,335	8,923,302	2,326,335
2010		P	SE		-	-	-	-
2011		G	SG		-	-	(10,603,216)	(2,764,295)
2012								
2013								
2014		<b>Total Plant Held For Future Use</b>		B10	<u><b>23,896,248</b></u>	<u><b>9,657,872</b></u>	<u><b>-</b></u>	<u><b>-</b></u>
2015								
2016	114	Electric Plant Acquisition Adjustments						
2017		P	S		11,763,784	-	11,763,784	-
2018		P	SG		144,704,699	37,725,010	3,518,456	917,274
2019		P	SG		-	-	-	-
2020		<b>Total Electric Plant Acquisition Adjustment</b>		B15	<u><b>156,468,483</b></u>	<u><b>37,725,010</b></u>	<u><b>15,282,240</b></u>	<u><b>917,274</b></u>

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
2021								
2022	115	Accum Provision for Asset Acquisition Adjustments						
2023		P	S		(3,612,186)	-	(3,612,186)	-
2024		P	SG		(137,980,477)	(35,971,982)	(827,259)	(215,669)
2025		P	SG		-	-	-	-
2026				B15	(141,592,663)	(35,971,982)	(4,439,444)	(215,669)
2027								
2028	128	Pensions						
2029		LABOR	SO		28,656,862	7,786,953	-	-
2030		<b>Total Pensions</b>		<b>B15</b>	<b>28,656,862</b>	<b>7,786,953</b>	<b>-</b>	<b>-</b>
2031								
2032	124	Weatherization						
2033		DMSC	S		629,485	-	629,485	-
2034		DMSC	SO		-	-	-	-
2035				B16	629,485	-	629,485	-
2036								
2037	182W	Weatherization						
2038		DMSC	S		198,594,752	-	198,594,752	-
2039		DMSC	SG		-	-	-	-
2040		DMSC	SGCT		-	-	-	-
2041		DMSC	SO		-	-	-	-
2042				B16	198,594,752	-	198,594,752	-
2043								
2044	186W	Weatherization						
2045		DMSC	S		-	-	-	-
2046		DMSC	CN		-	-	-	-
2047		DMSC	CNP		-	-	-	-
2048		DMSC	SG		-	-	-	-
2049		DMSC	SO		-	-	-	-
2050				B16	-	-	-	-
2051								
2052		<b>Total Weatherization</b>		<b>B16</b>	<b>199,224,237</b>	<b>-</b>	<b>199,224,237</b>	<b>-</b>
2053								
2054	151	Fuel Stock						
2055		P	DEU		-	-	-	-
2056		P	SE		206,953,359	51,879,348	177,743,272	44,556,924
2057		P	SE		-	-	-	-
2058		P	SE		-	-	-	-
2059				B13	206,953,359	51,879,348	177,743,272	44,556,924
2060								
2061	152	Fuel Stock - Undistributed						
2062		P	SE		-	-	-	-
2063					-	-	-	-
2064								
2065	25316	UAMPS Working Capital Deposit						
2066		P	SE		(2,806,000)	(703,412)	(2,803,000)	(702,660)
2067				B13	(2,806,000)	(703,412)	(2,803,000)	(702,660)
2068								
2069	25317	DG&T Working Capital Deposit						
2070		P	SE		(2,675,523)	(670,704)	(2,641,354)	(662,138)
2071				B13	(2,675,523)	(670,704)	(2,641,354)	(662,138)
2072								
2073	25319	Provo Working Capital Deposit						
2074		P	SE		-	-	-	-
2075					-	-	-	-
2076								
2077		<b>Total Fuel Stock</b>		<b>B13</b>	<b>201,471,836</b>	<b>50,505,232</b>	<b>172,298,918</b>	<b>43,192,126</b>
2078	154	Materials and Supplies						
2079		MSS	S		142,474,539	49,096,450	142,474,539	49,096,450
2080		MSS	SG		4,837,325	1,261,107	(504,572)	(131,544)
2081		MSS	SE		-	-	-	-
2082		MSS	SO		(1,284,248)	(348,970)	(1,284,248)	(348,970)
2083		MSS	SG		120,142,856	31,321,653	120,142,856	31,321,653
2084		MSS	SG		7,954	2,074	7,954	2,074
2085		MSS	SNPD		(1,308,783)	(346,469)	(1,308,783)	(346,469)
2086		MSS	SG		-	-	-	-
2087		MSS	SG		-	-	-	-
2088		MSS	SG		-	-	-	-
2089		MSS	SG		-	-	-	-
2090		MSS	SG		8,430,223	2,197,788	8,430,223	2,197,788
2091		MSS	SG		-	-	-	-
2092				B13	273,299,865	83,183,634	267,957,968	81,790,983
2093								
2094	163	Stores Expense Undistributed						
2095		MSS	SO		-	-	-	-
2096								
2097				B13	-	-	-	-

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
ACCT		FUNC						
2098								
2099	25318	Provo Working Capital Deposit						
2100		MSS	SG		(273,000)	(71,172)	(273,000)	(71,172)
2101								
2102				B13	(273,000)	(71,172)	(273,000)	(71,172)
2103								
2104		<b>Total Materials and Supplies</b>		<b>B13</b>	<b>273,026,865</b>	<b>83,112,462</b>	<b>267,684,968</b>	<b>81,719,811</b>
2105								
2106	165	Prepayments						
2107		DMSC	S		41,441,441	4,077,479	41,441,441	4,077,479
2108		GP	GPS		160,162	43,521	160,162	43,521
2109		PT	SG		3,834,288	999,612	3,834,288	999,612
2110		P	SE		45,735	11,465	45,735	11,465
2111		PTD	SO		22,072,726	5,997,840	22,072,726	5,997,840
2112		<b>Total Prepayments</b>		<b>B15</b>	<b>67,554,352</b>	<b>11,129,917</b>	<b>67,554,352</b>	<b>11,129,917</b>
2113								
2114	182M	Misc Regulatory Assets						
2115		DDS2	S		184,523,735	(11,607,347)	196,131,082	-
2116		DEFSG	SG		6,984,837	1,820,971	2,344,579	611,240
2117		P	SGCT		-	-	-	-
2118		DEFSG	SG-P		-	-	-	-
2119		P	SE		193,501,291	48,507,165	115,119,099	28,858,211
2120		P	SG		-	-	-	-
2121		DDSO2	SO		460,943,527	125,252,562	45,802,824	12,446,039
2122				B16	845,953,389	163,973,351	359,397,585	41,915,490
2123								
2124	186M	Misc Deferred Debits						
2125		LABOR	S		2,443,884	-	2,443,884	-
2126		P	SG		-	-	-	-
2127		P	SG		-	-	-	-
2128		DEFSG	SG		113,459,708	29,579,334	96,510,696	25,160,668
2129		LABOR	SO		78,384	21,299	78,384	21,299
2130		P	SE		809,282	202,872	809,282	202,872
2131		P	SG		-	-	-	-
2132		GP	EXCTAX		-	-	-	-
2133		<b>Total Misc. Deferred Debits</b>		<b>B11</b>	<b>116,791,258</b>	<b>29,803,505</b>	<b>99,842,246</b>	<b>25,384,840</b>
2134								
2135		Working Capital						
2136	CWC	Cash Working Capital						
2137		CWC	S		30,454,966	8,611,296	29,774,416	8,503,482
2138		CWC	SO		-	-	-	-
2139		CWC	SE		-	-	-	-
2140				B14	30,454,966	8,611,296	29,774,416	8,503,482
2141								
2142	OWC	Other Work. Cap.						
2143	131	Cash	GP	SNP	-	-	-	-
2144	135	Working Funds	GP	SG	-	-	-	-
2145	141	Notes Receivable	GP	SO	-	-	-	-
2146	143	Other A/R	GP	SO	38,636,523	10,498,734	38,636,523	10,498,734
2147	232	A/P	PTD	S	(18,882)	-	(18,882)	-
2148	232	A/P	PTD	SO	(6,155,803)	(1,672,721)	(6,155,803)	(1,672,721)
2149	232	A/P	P	SE	(3,116,112)	(781,151)	(3,116,112)	(781,151)
2150	232	A/P	T	SG	(3,331,340)	(868,492)	(3,331,340)	(868,492)
2151	2533	Other Msc. Df. Crd.	P	S	-	-	-	-
2152	2533	Other Msc. Df. Crd.	P	SE	(7,150,412)	(1,792,475)	(9,303,790)	(2,332,287)
2153	230	Asset Retir. Oblig.	P	SG	-	-	-	-
2154	230	Asset Retir. Oblig.	P	S	(2,978,037)	-	(2,978,037)	-
2155	254	Decom. Reg Liability	P	SG	-	-	-	-
2156	254	Reclam. Reg Liability	P	SE	-	-	-	-
2157	2533	Cholla Reclamation	P	SE	-	-	-	-
2158				B14	15,885,936	5,383,895	13,732,558	4,844,083
2159								
2160		<b>Total Working Capital</b>		<b>B14</b>	<b>46,340,902</b>	<b>13,995,191</b>	<b>43,506,974</b>	<b>13,347,565</b>
2161		Miscellaneous Rate Base						
2162	18221	Unrec Plant & Reg Study Costs						
2163		P	S		-	-	-	-
2164								
2165								
2166								
2167	18222	Nuclear Plant - Trojan						
2168		P	S		-	-	-	-
2169		P	TROJP		-	-	-	-
2170		P	TROJD		-	-	-	-
2171				B16	-	-	-	-

2020 PROTOCOL					JUNE 2021		DECEMBER 2023	
Year End					UNADJUSTED RESULTS		NORMALIZED RESULTS	
FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
2172								
2173								
2174								
2175	1869	Misc Deferred Debits-Trojan						
2176		P	S		-	-	-	-
2177		P	SG		-	-	-	-
2178					-	-	-	-
2179								
2180		<b>Total Miscellaneous Rate Base</b>		<b>B15</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
2181								
2182		<b>Total Rate Base Additions</b>			<b>1,817,791,769</b>	<b>371,717,509</b>	<b>1,220,352,075</b>	<b>217,391,352</b>
2183	235	Customer Service Deposits						
2184		CUST	S		-	-	-	-
2185		CUST	CN		-	-	-	-
2186		<b>Total Customer Service Deposits</b>		<b>B15</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
2187								
2188	2281	Prop Ins	PTD	S	(5,903,206)	20,937,606	(5,903,206)	20,937,606
2189	2282	Inj & Dam	PTD	SO	(141,155,665)	(38,356,344)	-	-
2190	2283	Pen & Ben	PTD	SO	(76,044,531)	(20,663,643)	(1,612,198)	(438,084)
2191	2282	Prov for Injurie	PTD	S	(12,416,392)	(12,416,392)	(12,416,392)	(12,416,392)
2192	254	Reg Liabilities	PTD	SO	(11,202,836)	(3,044,156)	(11,202,836)	(3,044,156)
2193	25335	Reg Liabilities	PTD	SE	(115,119,099)	(28,858,211)	(115,119,099)	(28,858,211)
2194				<b>B15</b>	<b>(361,841,730)</b>	<b>(82,401,140)</b>	<b>(146,253,732)</b>	<b>(23,819,237)</b>
2195								
2196	22841	Accum Misc. Operating Provisions						
2197		P	S		-	-	-	-
2198		P	SG		(234,853)	(61,227)	(234,853)	(61,227)
2199				<b>B15</b>	<b>(234,853)</b>	<b>(61,227)</b>	<b>(234,853)</b>	<b>(61,227)</b>
2200								
2201	254105	ARO	P	S	-	-	-	-
2202	230	ARO	P	TROJD	(5,565,959)	(1,441,094)	(5,565,959)	(1,441,094)
2203	254105	ARO	P	TROJD	-	-	-	-
2204	254		P	S	(1,823,401,237)	(385,458,427)	(1,807,135,161)	(369,192,352)
2205				<b>B15</b>	<b>(1,828,967,196)</b>	<b>(386,899,522)</b>	<b>(1,812,701,121)</b>	<b>(370,633,446)</b>
2206								
2207	252	Customer Advances for Construction						
2208		DPW	S		(1,709,876)	(1,424,117)	(23,708,755)	(2,069,907)
2209		DPW	SE		-	-	-	-
2210		T	SG		(102,399,151)	(26,695,809)	(80,400,272)	(20,960,626)
2211		DPW	SO		-	-	-	-
2212		CUST	CN		-	-	-	-
2213		<b>Total Customer Advances for Construction</b>		<b>B20</b>	<b>(104,109,027)</b>	<b>(28,119,926)</b>	<b>(104,109,027)</b>	<b>(23,030,533)</b>
2214								
2215	25398	SO2 Emissions						
2216		P	SE		-	-	-	-
2217					-	-	-	-
2218								
2219	25399	Other Deferred Credits						
2220		P	S		(405,265)	(204,430)	(405,265)	(204,430)
2221		LABOR	SO		-	-	-	-
2222		P	SG		(63,848,335)	(16,645,479)	(63,848,335)	(16,645,479)
2223		P	SE		(14,598,111)	(3,659,474)	(14,598,111)	(3,659,474)
2224				<b>B15</b>	<b>(78,851,712)</b>	<b>(20,509,383)</b>	<b>(78,851,712)</b>	<b>(20,509,383)</b>
2225								
2226	190	Accumulated Deferred Income Taxes						
2227		P	S		455,694,550	97,713,118	437,493,308	93,571,742
2228		CUST	CN		-	-	-	-
2229		LABOR	SO		126,177,788	34,286,394	53,932,101	14,655,014
2230		P	DGP		-	-	-	-
2231		IBT	IBT		-	-	-	-
2232		P	SG		-	-	-	-
2233		P	SG		-	-	-	-
2234		CUST	BADDEBT		4,646,301	2,252,764	4,933,337	2,391,934
2235		P	TROJD		1,298,701	336,249	1,288,724	333,666
2236		P	SG		1,952,500	509,023	1,374,949	358,454
2237		P	SE		31,308,246	7,848,393	1,888,088	473,309
2238		PTD	SNP		-	-	-	-
2239		DPW	SNPD		691,719	183,116	1,546,918	409,509
2240		P	SG		-	-	-	-
2241				<b>B19</b>	<b>621,769,805</b>	<b>143,129,058</b>	<b>502,457,426</b>	<b>112,193,627</b>
2242								
2243	281	Accumulated Deferred Income Taxes						
2244		P	S		-	-	-	-
2245		PT	SG		(148,004,159)	(38,585,191)	(0)	(0)
2246		T	SG		-	-	-	-
2247				<b>B19</b>	<b>(148,004,159)</b>	<b>(38,585,191)</b>	<b>(0)</b>	<b>(0)</b>



2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
2329	108EP	Experimental Plant - Accum Depr						
2330		P	SG		-	-	-	-
2331		P	SG		-	-	-	-
2332					-	-	-	-
2333								
2334		<b>Total Production Plant Accum Depreciation</b>		<b>B17</b>	<b>(3,999,206,912)</b>	<b>(1,040,782,292)</b>	<b>(6,007,178,858)</b>	<b>(1,699,703,228)</b>
2335								
2336		Summary of Prod Plant Depreciation by Factor						
2337		S			(6,998,866)	-	(190,194,333)	(183,195,467)
2338		DGP			-	-	-	-
2339		DGU			-	-	-	-
2340		SG			(3,992,208,046)	(1,040,782,292)	(5,816,984,525)	(1,516,507,761)
2341		SSGCH			-	-	-	-
2342		SSGCT			-	-	-	-
2343		<b>Total of Prod Plant Depreciation by Factor</b>			<b>(3,999,206,912)</b>	<b>(1,040,782,292)</b>	<b>(6,007,178,858)</b>	<b>(1,699,703,228)</b>
2344								
2345								
2346	108TP	Transmission Plant Accumulated Depr						
2347		T	SG		(353,157,214)	(92,069,293)	(353,157,214)	(92,069,293)
2348		T	SG		(426,788,101)	(111,265,118)	(426,788,101)	(111,265,118)
2349		T	SG		(1,221,447,907)	(318,435,647)	(1,394,500,313)	(363,551,001)
2350		<b>Total Trans Plant Accum Depreciation</b>		<b>B17</b>	<b>(2,001,393,221)</b>	<b>(521,770,058)</b>	<b>(2,174,445,627)</b>	<b>(566,885,412)</b>
2351	108360	Land and Land Rights						
2352		DPW	S		(10,029,714)	(2,430,506)	(11,725,368)	(2,747,792)
2353				<b>B17</b>	<b>(10,029,714)</b>	<b>(2,430,506)</b>	<b>(11,725,368)</b>	<b>(2,747,792)</b>
2354								
2355	108361	Structures and Improvements						
2356		DPW	S		(33,171,627)	(9,015,640)	(36,385,910)	(9,617,086)
2357				<b>B17</b>	<b>(33,171,627)</b>	<b>(9,015,640)</b>	<b>(36,385,910)</b>	<b>(9,617,086)</b>
2358								
2359	108362	Station Equipment						
2360		DPW	S		(354,040,121)	(101,151,751)	(380,710,272)	(106,142,180)
2361				<b>B17</b>	<b>(354,040,121)</b>	<b>(101,151,751)</b>	<b>(380,710,272)</b>	<b>(106,142,180)</b>
2362								
2363	108363	Storage Battery Equipment						
2364		DPW	S		-	-	-	-
2365				<b>B17</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
2366								
2367	108364	Poles, Towers & Fixtures						
2368		DPW	S		(676,436,873)	(255,299,196)	(711,267,917)	(261,797,228)
2369				<b>B17</b>	<b>(676,436,873)</b>	<b>(255,299,196)</b>	<b>(711,267,917)</b>	<b>(261,797,228)</b>
2370								
2371	108365	Overhead Conductors						
2372		DPW	S		(349,174,705)	(138,403,566)	(371,107,699)	(142,507,594)
2373				<b>B17</b>	<b>(349,174,705)</b>	<b>(138,403,566)</b>	<b>(371,107,699)</b>	<b>(142,507,594)</b>
2374								
2375	108366	Underground Conduit						
2376		DPW	S		(179,429,394)	(48,957,173)	(190,311,061)	(50,993,314)
2377				<b>B17</b>	<b>(179,429,394)</b>	<b>(48,957,173)</b>	<b>(190,311,061)</b>	<b>(50,993,314)</b>
2378								
2379	108367	Underground Conductors						
2380		DPW	S		(380,517,399)	(96,545,872)	(405,902,124)	(101,295,777)
2381				<b>B17</b>	<b>(380,517,399)</b>	<b>(96,545,872)</b>	<b>(405,902,124)</b>	<b>(101,295,777)</b>
2382								
2383	108368	Line Transformers						
2384		DPW	S		(604,818,198)	(252,937,731)	(643,242,258)	(260,127,513)
2385				<b>B17</b>	<b>(604,818,198)</b>	<b>(252,937,731)</b>	<b>(643,242,258)</b>	<b>(260,127,513)</b>
2386								
2387	108369	Services						
2388		DPW	S		(362,180,959)	(145,922,962)	(385,941,472)	(150,368,950)
2389				<b>B17</b>	<b>(362,180,959)</b>	<b>(145,922,962)</b>	<b>(385,941,472)</b>	<b>(150,368,950)</b>
2390								
2391	108370	Meters						
2392		DPW	S		(107,844,570)	(22,471,764)	(114,348,638)	(23,688,784)
2393				<b>B17</b>	<b>(107,844,570)</b>	<b>(22,471,764)</b>	<b>(114,348,638)</b>	<b>(23,688,784)</b>
2394								
2395								
2396								
2397	108371	Installations on Customers' Premises						
2398		DPW	S		(7,220,271)	(2,126,093)	(7,445,148)	(2,168,171)
2399				<b>B17</b>	<b>(7,220,271)</b>	<b>(2,126,093)</b>	<b>(7,445,148)</b>	<b>(2,168,171)</b>
2400								
2401	108372	Leased Property						
2402		DPW	S		-	-	-	-
2403				<b>B17</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
2404								
2405	108373	Street Lights						
2406		DPW	S		(34,236,684)	(12,787,348)	(35,847,149)	(13,088,693)
2407				<b>B17</b>	<b>(34,236,684)</b>	<b>(12,787,348)</b>	<b>(35,847,149)</b>	<b>(13,088,693)</b>

2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
FERC	DESCRIP	BUS	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
2408								
2409	108D00	Unclassified Dist Plant - Acct 300						
2410		DPW	S		-	-	-	-
2411				B17	-	-	-	-
2412								
2413	108DS	Unclassified Dist Sub Plant - Acct 300						
2414		DPW	S		-	-	-	-
2415				B17	-	-	-	-
2416								
2417	108DP	Unclassified Dist Sub Plant - Acct 300						
2418		DPW	S		6,095,445	2,061,813	6,095,445	2,061,813
2419				B17	6,095,445	2,061,813	6,095,445	2,061,813
2420								
2421								
2422		<b>Total Distribution Plant Accum Depreciation</b>		<b>B17</b>	<b>(3,093,005,071)</b>	<b>(1,085,987,789)</b>	<b>(3,288,139,572)</b>	<b>(1,122,481,268)</b>
2423								
2424		Summary of Distribution Plant Depr by Factor						
2425		S			(3,093,005,071)	(1,085,987,789)	(3,288,139,572)	(1,122,481,268)
2426								
2427		Total Distribution Depreciation by Factor			(3,093,005,071)	(1,085,987,789)	(3,288,139,572)	(1,122,481,268)
2428	108GP	General Plant Accumulated Depr						
2429		G-SITUS	S		(277,590,932)	(98,593,172)	(304,116,789)	(108,559,029)
2430		G-DGP	SG		(715,242)	(186,466)	(715,242)	(186,466)
2431		G-DGU	SG		(1,951,711)	(508,818)	(1,951,711)	(508,818)
2432		G-SG	SG		(127,433,166)	(33,222,262)	(138,970,814)	(36,230,166)
2433		CUST	CN		(7,270,206)	(2,253,032)	(6,909,506)	(2,141,251)
2434		PTD	SO		(116,526,662)	(31,663,885)	(126,079,770)	(34,259,759)
2435		P	SE		(1,538,215)	(385,602)	(1,494,391)	(374,616)
2436		G-SG	SG		(130,406)	(33,997)	(130,406)	(33,997)
2437		G-SG	SG		-	-	-	-
2438				B17	(533,156,539)	(166,847,234)	(580,368,628)	(182,294,103)
2439								
2440								
2441	108MP	Mining Plant Accumulated Depr.						
2442		P	S		-	-	-	-
2443		P	SE		-	-	-	-
2444				B17	-	-	-	-
2445	108MP	Less Centralia Situs Depreciation						
2446		P	S		-	-	-	-
2447				B17	-	-	-	-
2448								
2449	1081390	Accum Depr - Capital Lease						
2450		PTD	SO		-	-	-	-
2451				B17	-	-	-	-
2452								
2453		Remove Capital Leases			-	-	-	-
2454				B17	-	-	-	-
2455								
2456	1081399	Accum Depr - Capital Lease						
2457		P	S		-	-	-	-
2458		P	SE		-	-	-	-
2459				B17	-	-	-	-
2460								
2461		Remove Capital Leases			-	-	-	-
2462				B17	-	-	-	-
2463								
2464								
2465		<b>Total General Plant Accum Depreciation</b>		<b>B17</b>	<b>(533,156,539)</b>	<b>(166,847,234)</b>	<b>(580,368,628)</b>	<b>(182,294,103)</b>
2466								
2467								
2468								
2469		Summary of General Depreciation by Factor						
2470		S			(277,590,932)	(98,593,172)	(304,116,789)	(108,559,029)
2471		DGP			-	-	-	-
2472		DGU			-	-	-	-
2473		SE			(1,538,215)	(385,602)	(1,494,391)	(374,616)
2474		SO			(116,526,662)	(31,663,885)	(126,079,770)	(34,259,759)
2475		CN			(7,270,206)	(2,253,032)	(6,909,506)	(2,141,251)
2476		SG			(130,230,525)	(33,951,543)	(141,768,172)	(36,959,447)
2477		DEU			-	-	-	-
2478		SSGCT			-	-	-	-
2479		SSGCH			-	-	-	-
2480		Remove Capital Leases			-	-	-	-
2481		Total General Depreciation by Factor			(533,156,539)	(166,847,234)	(580,368,628)	(182,294,103)
2482								
2483								
2484		<b>Total Accum Depreciation - Plant In Service</b>		<b>B17</b>	<b>(9,626,761,743)</b>	<b>(2,815,387,372)</b>	<b>(12,050,132,685)</b>	<b>(3,571,364,011)</b>



2020 PROTOCOL				JUNE 2021		DECEMBER 2023		
Year End				UNADJUSTED RESULTS		NORMALIZED RESULTS		
ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	TOTAL	OREGON	TOTAL	OREGON
2485	111SP	Accum Prov for Amort-Steam						
2486		P	SG		-	-	-	-
2487		P	SG		-	-	-	-
2488				B18	-	-	-	-
2489								
2490								
2491	111GP	Accum Prov for Amort-General						
2492		G-SITUS	S		(11,923,722)	(4,741,005)	(12,632,235)	(5,225,362)
2493		CUST	CN		-	-	-	-
2494		I-SG	SG		-	-	-	-
2495		PTD	SO		(1,174,857)	(319,245)	(1,337,295)	(363,384)
2496		P	SE		-	-	-	-
2497				B18	(13,098,578)	(5,060,250)	(13,969,530)	(5,588,746)
2498								
2499								
2500	111HP	Accum Prov for Amort-Hydro						
2501		P	SG		-	-	-	-
2502		P	SG		-	-	-	-
2503		P	SG		(3,139,235)	(818,409)	(3,606,778)	(940,299)
2504		P	SG		-	-	-	-
2505				B18	(3,139,235)	(818,409)	(3,606,778)	(940,299)
2506								
2507								
2508	111IP	Accum Prov for Amort-Intangible Plant						
2509		I-SITUS	S		30,478,582	(129,177)	30,343,931	(140,175)
2510		I-DGP	SG		-	-	-	-
2511		I-DGU	SG		(397,058)	(103,514)	(397,058)	(103,514)
2512		P	SE		(1,897)	(476)	84,709	21,235
2513		I-SG	SG		(105,977,548)	(27,628,709)	(115,585,895)	(30,133,638)
2514		I-SG	SG		(114,544,697)	(29,862,194)	(118,482,024)	(30,888,669)
2515		I-SG	SG		(5,755,401)	(1,500,453)	(5,961,962)	(1,554,304)
2516		CUST	CN		(162,639,670)	(50,401,918)	(182,729,117)	(56,627,623)
2517		P	SG		-	-	-	-
2518		P	SG		-	-	-	-
2519		PTD	SO		(316,598,295)	(86,029,514)	(339,134,793)	(92,153,375)
2520				B18	(675,435,985)	(195,655,955)	(731,862,209)	(211,580,064)
2521	111IP	Less Non-Regulated Plant						
2522		NUTIL	OTH		-	-	-	-
2523					(675,435,985)	(195,655,955)	(731,862,209)	(211,580,064)
2524								
2525	111390	Accum Amtr - Capital Lease						
2526		G-SITUS	S		-	-	-	-
2527		P	SG		-	-	-	-
2528		PTD	SO		-	-	-	-
2529				B9	-	-	-	-
2530								
2531		Remove Capital Lease Amtr			-	-	-	-
2532								
2533		<b>Total Accum Provision for Amortization</b>		<b>B18</b>	<b>(691,673,798)</b>	<b>(201,534,614)</b>	<b>(749,438,517)</b>	<b>(218,109,109)</b>
2534								
2535								
2536								
2537								
2538		Summary of Amortization by Factor						
2539		S			18,554,860	(4,870,181)	17,711,696	(5,365,536)
2540		DGP			-	-	-	-
2541		DGU			-	-	-	-
2542		SE			(1,897)	(476)	84,709	21,235
2543		SO			(317,773,151)	(86,348,759)	(340,472,088)	(92,516,759)
2544		CN			(162,639,670)	(50,401,918)	(182,729,117)	(56,627,623)
2545		SSGCT			-	-	-	-
2546		SSGCH			-	-	-	-
2547		SG			(229,813,940)	(59,913,280)	(244,033,718)	(63,620,425)
2548		Less Capital Lease			-	-	-	-
2549		<b>Total Provision For Amortization by Factor</b>			<b>(691,673,798)</b>	<b>(201,534,614)</b>	<b>(749,438,517)</b>	<b>(218,109,109)</b>

Tab % RehWgW

**PacifiCorp**  
**Oregon General Rate Case – December 2023**  
**Revenue Adjustment Index**

The Company used actual revenue for the 12 months ended June 30, 2021 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 2023 test period.

- 3.1 Pro Forma Revenue
- 3.2 REC Revenue
- 3.3 Wheeling Revenue
- 3.4 Ancillary Revenue
- 3.5 Fly Ash Revenue

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Tab 3 Adjustment Summary**

	Total Adjustments	3.1 Pro Forma Revenue	3.2 REC Revenue	3.3 Wheeling Revenue	3.4 Ancillary Revenue	3.5 Fly Ash Revenue
1 Operating Revenues:						
2 General Business Revenues	(61,204,592)	(61,204,592)	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-
5 Other Operating Revenues	4,704,600	-	(1,641,065)	8,265,447	(2,748,201)	828,419
6 Total Operating Revenues	(56,499,992)	(61,204,592)	(1,641,065)	8,265,447	(2,748,201)	828,419
7						
8 Operating Expenses:						
9 Steam Production	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-
12 Other Power Supply	-	-	-	-	-	-
13 Transmission	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	-	-	-	-	-	-
19						
20 Total O&M Expenses	-	-	-	-	-	-
21						
22 Depreciation	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-
25 Income Taxes - Federal	(11,325,777)	(12,268,844)	(328,962)	1,656,860	(550,894)	166,062
26 Income Taxes - State	(2,564,975)	(2,778,553)	(74,501)	375,233	(124,762)	37,608
27 Income Taxes - Def Net	-	-	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-
30						
31 Total Operating Expenses:	(13,890,752)	(15,047,397)	(403,462)	2,032,094	(675,656)	203,670
32						
33 Operating Rev For Return:	(42,609,240)	(46,157,195)	(1,237,602)	6,233,353	(2,072,544)	624,749
34						
35 Rate Base:						
36 Electric Plant In Service	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-
44 Working Capital	(131,295)	(142,228)	(3,814)	19,207	(6,386)	1,925
45 Weatherization Loans	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	(131,295)	(142,228)	(3,814)	19,207	(6,386)	1,925
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-
53 Accum Def Income Tax	-	-	-	-	-	-
54 Unamortized ITC	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-
58						
59 Total Rate Base Deductions	-	-	-	-	-	-
60						
61 Total Rate Base:	(131,295)	(142,228)	(3,814)	19,207	(6,386)	1,925
62						
63 Return on Rate Base	-0.891%	-0.965%	-0.026%	0.130%	-0.043%	0.013%
64						
65 Return on Equity	-1.706%	-1.848%	-0.050%	0.250%	-0.083%	0.025%
66						
67 TAX CALCULATION:						
68 Operating Revenue	(56,499,992)	(61,204,592)	(1,641,065)	8,265,447	(2,748,201)	828,419
69 Other Deductions	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-
71 Interest	(2,745)	(2,974)	(80)	402	(134)	40
72 Schedule "M" Additions	-	-	-	-	-	-
73 Schedule "M" Deductions	-	-	-	-	-	-
74 Income Before Tax	(56,497,246)	(61,201,618)	(1,640,985)	8,265,045	(2,748,067)	828,379
75						
76 State Income Taxes	(2,564,975)	(2,778,553)	(74,501)	375,233	(124,762)	37,608
77 Taxable Income	(53,932,271)	(58,423,065)	(1,566,484)	7,889,812	(2,623,305)	790,771
78						
79 Federal Income Taxes + Other	(11,325,777)	(12,268,844)	(328,962)	1,656,860	(550,894)	166,062
APPROXIMATE PRICE CHANGE	58,398,993	63,260,742	1,695,882	(8,541,539)	2,839,999	(856,091)

**PacifiCorp  
Oregon General Rate Case - December 2023  
Pro Forma Revenues**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Revenue:</b>							
Residential	440	3	(45,321,380)	OR	Situs	(45,321,380)	3.1.1
Commercial	442	3	(5,691,236)	OR	Situs	(5,691,236)	3.1.1
Industrial <sup>1</sup>	442	3	(8,680,067)	OR	Situs	(8,680,067)	3.1.1
Public St. & Hwy	444	3	(1,511,908)	OR	Situs	(1,511,908)	3.1.1
Total			<u>(61,204,592)</u>			<u>(61,204,592)</u>	3.1.1

<sup>1</sup>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 2023 based on forecasted loads. Page 3.1.4 shows a breakout between the TAM and general rate case revenues.

	A	B	C	D	E	F	G	H	I	J	K	L	M
	Total Revenue	Normalizing Adjustments <sup>1</sup> (305 Report)	Unadjusted Revenues	Remove Tariff Riders <sup>1</sup>	Actual Base Rate Revenues	Normalizing Adjustments <sup>2</sup>	Temperature Normalization	Total Type 1 Adjusted Revenue	Type 2 Annualized Price Change <sup>3</sup>	Total Type 2 Adjusted Revenue	Type 3 Pro Forma Price Change <sup>4</sup>	Total Oregon Forecast Revenue	Total Adjustment
Residential	\$643,283,576	\$15,559,040	\$658,842,617	(\$4,028,670)	\$654,813,947	(\$4,865,957)	(\$1,359,796)	\$648,588,195	(\$19,894,626)	\$628,693,569	(\$15,172,332)	\$613,521,236	<b>(\$45,321,380)</b>
Commercial	\$513,275,771	(\$16,105,796)	\$497,169,975	(\$10,760,501)	\$486,409,474	(\$1,657,701)	(\$3,180,119)	\$481,571,654	(\$19,580,460)	\$461,991,194	\$29,487,544	\$491,478,738	<b>(\$5,691,236)</b>
Industrial	\$118,599,710	(\$2,417,253)	\$116,182,457	(\$3,459,754)	\$112,722,703	\$4,832,059	\$0	\$117,554,763	(\$2,575,981)	\$114,978,782	(\$11,348,317)	\$103,630,464	<b>(\$12,551,993)</b>
Irrigation	\$30,442,034	(\$104,487)	\$30,337,548	(\$191,256)	\$30,146,292	\$2,401,471	(\$1,379,464)	\$31,168,299	(\$586,084)	\$30,582,215	\$3,627,258	\$34,209,473	<b>\$3,871,925</b>
Public St & Hwy	\$5,982,047	(\$175,520)	\$5,806,526	(\$11,596)	\$5,794,930	(\$1,206,366)	\$0	\$4,588,564	(\$170,732)	\$4,417,833	(\$123,215)	\$4,294,618	<b>(\$1,511,908)</b>
<b>Total Oregon</b>	<b>\$1,311,583,139</b>	<b>(\$3,244,016)</b>	<b>\$1,308,339,123</b>	<b>(\$18,451,776)</b>	<b>\$1,289,887,347</b>	<b>(\$496,493)</b>	<b>(\$5,919,378)</b>	<b>\$1,283,471,475</b>	<b>(\$42,807,883)</b>	<b>\$1,240,663,593</b>	<b>\$6,470,938</b>	<b>\$1,247,134,531</b>	<b>(\$61,204,592)</b>
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

<sup>1</sup> Solar Feed-In Revenue, Gain on Sale of Asset, Revenue Accounting Adjustments, Customer Bill Credits, Community Solar Revenue, Other Customer Retail Revenue, Revenue Adjustment I&D Reserve, DSM, Blue Sky, Inome Tax Deferral Adjustments BPA (Sch 98), Pilot Program Cost Adjustment (Sch 95), Oregon Corporate Activities Tax Recovery Adjustment (104), Replaced Meter Deferred Amounts Adjustment (194), Federal Tax Act Adjustment (195), Deer Creek Mine Closure Deferred Amounts Adjustment (Sch 198), Renewable Resource Deferral Adjustment (Sch 203), Oregon Solar Incentive Program (Sch 204) and Community Solar Adjustment (207).

<sup>2</sup> Removal of Irrigation Demand Charge Accrual (net zero for calendar year), Rate Mitigation Adjustment (299), & Out of Period adjustment

<sup>3</sup> Includes rate changes for: Renewable Adjustment Clause (RAC) and Transition Adjustment Mechanism (TAM) effective September 18, 2020; RAC effective November 1, 2020; TAM effective December 11, 2020; General Rate Case (GRC) and TAM effective January 1, 2021; GRC update effective January 12, 2021; GRC update effective April 9, 2021. Includes adjustment bringing direct access consumers to cost of service.

<sup>4</sup> TAM rate change effective January 1, 2022; adjustment to forecast.

	A	B	C	D	E	F	G	H
	Total MWhs	Normalizing Adjustments MWhs <sup>1</sup>	Temperature Adjustments MWhs	Type 1 Adjusted MWhs	Type 2 Adjustments MWhs <sup>2</sup>	Total Oregon Adjusted Actual MWhs	Type 3 Adjustment MWhs <sup>3</sup>	Total Oregon Forecast MWhs
Residential	5,917,093	(1,093)	(14,000)	5,902,000	(57)	5,901,942	(121,109)	5,780,833
Commercial	5,623,745	558	(53,091)	5,571,212	82,869	5,654,081	667,468	6,321,549
Industrial	1,563,748	3,480	0	1,567,229	33,800	1,601,028	(135,519)	1,465,509
Irrigation	313,870	4,279	(14,953)	303,197	120	303,317	30,399	333,716
Public St & Hwy	38,510	(1,794)	0	36,716	(1,057)	35,659	337	35,996
Total Oregon	13,456,967	5,431	(82,044)	13,380,353	115,675	13,496,028	441,575	13,937,602
Source / Formula	305 Report	Table 2	Table 2	A + B + C	Table 2	D + E	Table 2	F + G

<sup>1</sup> Out of Period adjustment.

<sup>2</sup> Adjustment made to reconcile booked MWh with blocking MWh. Includes adjustment to incorporate direct access MWh.

<sup>3</sup> Adjustment from actual to forecast.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Present TAM Revenues In Rates**  
**Forecast 12 Months Ended December 31, 2023**

PAGE 3.1.3

Base Rate Schedule	MWH	TAM Collection (Schedule 201 Revenue)
4	5,633,856	\$123,221,632
23	1,137,011	\$23,580,111
28	1,992,271	\$41,574,167
30	1,281,581	\$26,124,496
41	263,565	\$5,202,762
47	29,109	\$530,243
48	3,555,464	\$67,892,212
848	0	\$0
15	8,260	\$69,726
51	23,893	\$235,901
53	11,452	\$95,050
54	1,141	\$9,472
<b>Total</b>	<b>13,937,602</b>	<b>\$288,535,772</b>

Comparison to UE 390	MWH	Approved TAM
2022 Test Period	13,592,146	\$282,127,243
Difference resulting from change in test period	345,457	\$6,408,529
Percentage Change	2.5%	2.3%



**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
Revenue split between TAM and GRC Proforma Revenue

Total Revenue - 2023	TAM/ NPC	NON-TAM / NON NPC
\$1,247,134,531	\$288,535,772	\$958,598,759
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 2023  
Historical 12 Months Ended June 2021; Forecast 12 Months Ended December 2023  
Revenue, kWh and Customer Adjustments

	CUSTOMERS				KWH			
	305 Average Customers	Adjustment Customers	Forecast Customers	305 Booked kWh	Type 1			Total Type 1 Adjusted kWh
					Normalizing Adjustment kWh	Temperature Adjustments kWh	Type 1 Adjustments kWh	
<b>Residential</b>								
15	2,295	-153	2,143	1,962,387	4,099		4,099	1,966,486
4	521,249	13,810	535,059	5,770,434,457	(1,061,801)	(13,615,937)	(14,677,738)	5,755,756,719
23	17,260	458	17,718	98,924,861	(37,972)	(383,917)	(421,889)	98,502,972
28	232	8	239	44,978,994	2,485		2,485	44,981,479
BPA Balancing Account	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Gain on Sale of Asset	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Customer Bill Credits	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
Income Tax Deferral Adjustments	0			0			0	0
Unbilled	0			792,000				792,000
AGA	0			0			0	0
<b>Total Residential</b>	<b>541,036</b>	<b>14,122</b>	<b>555,159</b>	<b>5,917,092,699</b>	<b>(1,093,189)</b>	<b>(13,999,854)</b>	<b>(15,093,043)</b>	<b>5,901,999,656</b>
<b>Commercial</b>								
15	3,645	-128	3,517	6,325,989	(5,615)		(5,615)	6,320,374
23	64,797	829	65,626	1,064,697,024	214,380	(9,360,496)	(9,146,116)	1,055,650,908
28	9,582	235	9,817	1,885,457,787	(3,098)	(17,843,223)	(17,852,321)	1,867,605,466
30	681	-14	667	1,026,338,858	(610,619)	(10,452,794)	(11,063,413)	1,015,275,445
47	5	0	5	27,647,250	(1,141,500)		(1,141,500)	26,505,750
48	103	0	103	1,471,512,543	2,108,800	(15,434,743)	(13,325,943)	1,458,186,600
54	102	0	102	1,308,442	2,091		2,091	1,310,533
BPA Balancing Account	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Gain on Sale of Asset	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Customer Bill Credits	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
Income Tax Deferral Adjustments	0			0			0	0
Unbilled	0			140,457,000				140,457,000
AGA	0			0			0	0
<b>Total Commercial</b>	<b>78,916</b>	<b>921</b>	<b>79,837</b>	<b>5,623,744,893</b>	<b>558,439</b>	<b>(53,091,256)</b>	<b>(52,532,817)</b>	<b>5,571,212,076</b>
<b>Industrial</b>								
15	115	-1	114	243,549	412		412	243,961
23	976	-6	970	17,980,256	10,389	0	10,389	17,990,645
28	404	2	406	81,679,641	(84,584)	0	(84,584)	81,595,057
30	128	2	130	176,724,046	14,680		14,680	176,738,726
47	1	0	1	2,230,154	0		0	2,230,154
BPA Balancing Account	0	83	83	1,270,091,830	3,539,400		3,539,400	1,273,631,230
Solar Feed-In Revenue	0			0			0	0
Gain on Sale of Asset	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Customer Bill Credits	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
Income Tax Deferral Adjustments	0			0			0	0
Unbilled	0			14,799,000				14,799,000
AGA	0			0			0	0
<b>Total Industrial</b>	<b>1,708</b>	<b>(4)</b>	<b>1,704</b>	<b>1,563,748,476</b>	<b>3,480,297</b>	<b>0</b>	<b>3,480,297</b>	<b>1,567,228,773</b>
<b>Irrigation</b>								
41	7,981	16	7,997	234,978,837	2,358,472	(13,095,200)	(10,736,728)	224,242,109
23	1	0	1	4,255	629		629	4,884
48	5	0	5	58,858,400	1,920,000	(1,857,785)	62,215	58,920,615
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
Gain on Sale of Asset	0			0			0	0
Revenue Accounting Adjustment	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
Income Tax Deferral Adjustments	0			0			0	0
Unbilled	0			20,029,000				20,029,000
AGA	0			0			0	0
<b>Total Irrigation</b>	<b>7,987</b>	<b>16</b>	<b>8,003</b>	<b>313,870,492</b>	<b>4,278,101</b>	<b>(14,952,985)</b>	<b>(10,673,884)</b>	<b>303,196,608</b>
<b>Lighting</b>								
15	36	0	36	55,138			0	55,138
23	14	0	14	596,326	0		0	596,326
50	94	-94		3,494,666	0		0	3,494,666
51	1,004	104	1,108	23,018,466	(1,161,751)		(1,161,751)	21,856,715
52	16	-16		135,913	0		0	135,913
53	313	1	314	11,373,465	(632,376)		(632,376)	10,741,089
Solar Feed-In Revenue	0			0			0	0
Gain on Sale of Asset	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Community Solar Revenue	0			0			0	0
DSM	0			0			0	0
Income Tax Deferral Adjustments	0			0			0	0
Unbilled	0			(164,000)				(164,000)
AGA	0			0			0	0
<b>Total Lighting</b>	<b>1,477</b>	<b>(5)</b>	<b>1,472</b>	<b>38,509,974</b>	<b>(1,794,127)</b>	<b>0</b>	<b>(1,794,127)</b>	<b>36,715,847</b>
<b>TOTAL COMPANY</b>	<b>631,123</b>	<b>15,051</b>	<b>646,174</b>	<b>13,456,966,534</b>	<b>5,430,521</b>	<b>(82,044,096)</b>	<b>(76,613,575)</b>	<b>13,380,352,959</b>

PacifiCorp  
Oregon General Rate Case - December 2023  
Historical 12 Months Ended June 2021; Foreca  
Revenue, kWh and Customer Adjustments

		Type 2		Type 3		305 Booked Revenues	Remove Tariff Riders \$	Actual Base Rate Revenues
		Blocking Adjustment kWh	Total Type 2 Adjusted kWh	Forecast Adjustment kWh	Total Type 3 Adjusted kWh			
<b>Residential</b>	15	(22,973)	1,943,513	(111,996)	1,831,517	\$296,609	\$12,697	\$309,306
	4	26,448	5,755,783,167	(121,926,689)	5,633,856,479	\$589,286,974	\$49,490,861	\$638,777,835
	23	(60,735)	98,442,237	(2,352,104)	96,090,133	\$12,460,168	\$823,622	\$13,283,791
	28	(26)	44,981,453	4,073,407	49,054,860	\$3,643,986	\$278,862	\$3,922,848
	BPA Balancing Account		0	0	0	(\$192,823)	\$192,823	\$0
	Solar Feed-In Revenue		0	0	0	\$2,229,585	(\$2,229,585)	\$0
	Gain on Sale of Asset		0	0	0	\$17,372	(\$17,372)	\$0
	Revenue Accounting Adjustment		0	0	0	(\$2,570,998)	\$2,570,998	\$0
	Customer Bill Credits		0	0	0	(\$165,055)	\$165,055	\$0
	Community Solar Revenue		0	0	0	\$234,155	(\$234,155)	\$0
	Revenue Adjustment - I&D Reserve		0	0	0	(\$723,515)	\$723,515	\$0
	DSM		0	0	0	\$20,507,206	(\$20,507,206)	\$0
	Blue Sky		0	0	0	\$961,756	(\$961,756)	\$0
	Income Tax Deferral Adjustments		0	0	0	\$18,777,988	(\$18,777,988)	\$0
Unbilled		792,000	0	(792,000)	0	\$1,485,000	\$0	
AGA		0	0	0	0	\$5,168	\$5,168	
<b>Total Residential</b>	<b>(57,286)</b>	<b>5,901,942,370</b>	<b>(121,109,381)</b>	<b>5,780,832,989</b>	<b>\$643,283,576</b>	<b>\$11,530,371</b>	<b>\$654,813,947</b>	
<b>Commercial</b>	15	(86,642)	6,233,732	(108,072)	6,125,660	\$834,201	\$19,063	\$853,265
	23	404,577	1,055,955,485	(32,167,089)	1,023,788,396	\$116,350,093	\$1,870,811	\$118,220,904
	28	5,398,837	1,873,004,303	(7,813,105)	1,865,191,198	\$166,712,986	\$2,428,563	\$169,141,550
	30	46,010,169	1,061,285,614	53,675,458	1,114,961,072	\$81,751,815	\$1,208,280	\$82,960,094
	47	0	26,505,750	588,744	27,094,494	\$3,198,340	\$18,006	\$3,216,346
	48	31,141,972	1,489,328,572	793,918,184	2,283,246,756	\$97,356,107	\$1,429,426	\$98,785,533
	54	0	1,310,533	(169,291)	1,141,242	\$124,979	\$1,669	\$126,648
	BPA Balancing Account		0	0	0	\$3,623	(\$3,623)	\$0
	Solar Feed-In Revenue		0	0	0	\$1,982,204	(\$1,982,204)	\$0
	Gain on Sale of Asset		0	0	0	\$16,222	(\$16,222)	\$0
	Revenue Accounting Adjustment		0	0	0	\$1,014,355	(\$1,014,355)	\$0
	Customer Bill Credits		0	0	0	(\$20,212)	\$20,212	\$0
	Community Solar Revenue		0	0	0	\$169,681	(\$169,681)	\$0
	Other Customer Retail Rev		0	0	0	\$19,898	(\$19,898)	\$0
Revenue Adjustment - I&D Reserve		0	0	0	(\$550,246)	\$550,246	\$0	
DSM		0	0	0	\$12,360,668	(\$12,360,668)	\$0	
Blue Sky		0	0	0	\$1,059,754	(\$1,059,754)	\$0	
Income Tax Deferral Adjustments		0	0	0	\$17,786,169	(\$17,786,169)	\$0	
Unbilled		140,457,000	0	(140,457,000)	0	\$9,873,000	\$9,873,000	
AGA		0	0	0	\$3,232,134	\$0	\$3,232,134	
<b>Total Commercial</b>	<b>82,868,913</b>	<b>5,654,080,989</b>	<b>667,467,829</b>	<b>6,321,548,818</b>	<b>\$513,275,771</b>	<b>(\$26,866,297)</b>	<b>\$486,409,474</b>	
<b>Industrial</b>	15	158	244,119	3,427	247,546	\$29,129	\$517	\$29,646
	23	(24)	17,990,621	(1,457,448)	16,533,173	\$1,993,674	\$28,628	\$2,022,303
	28	(34)	81,595,023	(3,570,368)	78,024,655	\$7,815,407	\$86,126	\$7,901,533
	30	24	176,738,750	(10,118,492)	166,620,258	\$15,624,654	\$136,881	\$15,761,534
	47	0	2,230,154	(216,000)	2,014,154	\$898,001	(\$2,869)	\$895,133
	33,799,589	1,307,430,819	(105,361,574)	1,202,069,245	\$83,696,157	\$913,759	\$84,609,917	
	BPA Balancing Account		0	0	0	\$51	(\$51)	\$0
	Solar Feed-In Revenue		0	0	0	\$554,274	(\$554,274)	\$0
	Gain on Sale of Asset		0	0	0	\$4,791	(\$4,791)	\$0
	Revenue Accounting Adjustment		0	0	0	(\$489,343)	\$489,343	\$0
	Customer Bill Credits		0	0	0	(\$3,613)	\$3,613	\$0
	Community Solar Revenue		0	0	0	\$47,336	(\$47,336)	\$0
	Revenue Adjustment - I&D Reserve		0	0	0	(\$179,951)	\$179,951	\$0
	DSM		0	0	0	\$949,796	(\$949,796)	\$0
Blue Sky		0	0	0	\$581,738	(\$581,738)	\$0	
Income Tax Deferral Adjustments		0	0	0	\$5,574,970	(\$5,574,970)	\$0	
Unbilled		14,799,000	0	(14,799,000)	0	\$1,390,000	\$1,390,000	
AGA		0	0	0	\$112,639	\$0	\$112,639	
<b>Total Industrial</b>	<b>33,799,713</b>	<b>1,601,028,486</b>	<b>(135,519,455)</b>	<b>1,465,509,031</b>	<b>\$118,599,710</b>	<b>(\$5,877,007)</b>	<b>\$112,722,703</b>	
<b>Irrigation</b>	41	120,790	224,362,899	39,202,171	263,565,070	\$22,908,886	\$1,456,716	\$24,365,602
	23	(629)	4,255	(1,232)	3,023	\$663	\$4	\$667
	48	0	58,920,615	11,227,218	70,147,833	\$3,864,294	\$346,646	\$4,210,940
	BPA Balancing Account		0	0	0	\$76,703	(\$76,703)	\$0
	BPA Adjustment		0	0	0	\$272,963	(\$272,963)	\$0
	Demand Charge Accrual		0	0	0	\$193,000	\$0	\$193,000
	Solar Feed-In Revenue		0	0	0	\$72,078	(\$72,078)	\$0
	Gain on Sale of Asset		0	0	0	\$116	(\$116)	\$0
	Revenue Accounting Adjustment		0	0	0	(\$75,223)	\$75,223	\$0
	Community Solar Revenue		0	0	0	\$8,305	(\$8,305)	\$0
	Revenue Adjustment - I&D Reserve		0	0	0	(\$31,031)	\$31,031	\$0
	DSM		0	0	0	\$773,574	(\$773,574)	\$0
	Blue Sky		0	0	0	\$518	(\$518)	\$0
	Income Tax Deferral Adjustments		0	0	0	\$1,001,106	(\$1,001,106)	\$0
Unbilled		20,029,000	0	(20,029,000)	0	\$1,205,000	\$1,205,000	
AGA		0	0	0	\$171,083	\$0	\$171,083	
<b>Total Irrigation</b>	<b>120,161</b>	<b>303,316,769</b>	<b>30,399,157</b>	<b>333,715,926</b>	<b>\$30,442,034</b>	<b>(\$295,742)</b>	<b>\$30,146,292</b>	
<b>Lighting</b>	15	(586)	54,552	679	55,231	\$9,118	\$166	\$9,284
	23	(3)	596,323	(325)	595,998	\$139,943	\$502	\$140,446
	50	(3,494,666)	0	0	0	\$453,624	\$13,909	\$467,534
	51	2,579,332	24,436,047	(543,468)	23,892,579	\$4,287,037	\$54,508	\$4,341,544
	52	(135,913)	0	0	0	\$20,380	\$628	\$21,008
	53	(4,993)	10,736,096	715,684	11,451,780	\$843,364	\$12,750	\$856,115
	Solar Feed-In Revenue		0	0	0	\$12,836	(\$12,836)	\$0
	Gain on Sale of Asset		0	0	0	\$834	(\$834)	\$0
	Revenue Accounting Adjustment		0	0	0	(\$12,537)	\$12,537	\$0
	Community Solar Revenue		0	0	0	\$894	(\$894)	\$0
	DSM		0	0	0	\$137,330	(\$137,330)	\$0
	Income Tax Deferral Adjustments		0	0	0	\$130,222	(\$130,222)	\$0
	Unbilled		(164,000)	0	164,000	0	(\$41,000)	(\$41,000)
	AGA		0	0	0	0	\$0	\$0
<b>Total Lighting</b>	<b>(1,056,829)</b>	<b>35,659,018</b>	<b>336,570</b>	<b>35,995,588</b>	<b>\$5,982,047</b>	<b>(\$187,116)</b>	<b>\$5,794,930</b>	
<b>TOTAL COMPANY</b>	<b>115,674,672</b>	<b>13,496,027,631</b>	<b>441,574,720</b>	<b>13,937,602,352</b>	<b>\$1,311,583,139</b>	<b>(\$21,695,792)</b>	<b>\$1,289,887,347</b>	

PacifiCorp  
Oregon General Rate Case - December 2023  
Historical 12 Months Ended June 2021; Foreca  
Revenue, kWh and Customer Adjustments

		REVENUES						
		Type 1		Type 2		Type 3		
		Normalizing Adjustments \$	Temperature Adjustment \$	Total Type 1 Adjusted Revenues	Type 2 Adjustments \$	Total Type 2 Adjusted Revenues	Type 3 Adjustments \$	Total Adjusted Revenues
<b>Residential</b>								
	15	(\$35,347)		\$273,959	(\$19,955)	\$254,004	(\$266)	\$253,738
	4	(\$4,506,494)	(\$1,324,480)	\$632,946,861	(\$19,533,743)	\$613,413,118	(\$16,690,537)	\$596,722,581
	23	(\$211,229)	(\$35,315)	\$13,037,246	(\$113,577)	\$12,923,669	(\$230,770)	\$12,692,899
	28	(\$112,887)	\$0	\$3,809,961	(\$227,351)	\$3,582,610	\$264,241	\$3,846,851
	BPA Balancing Account	\$0		\$0		\$0		\$0
	Solar Feed-In Revenue	\$0		\$0		\$0		\$0
	Gain on Sale of Asset	\$0		\$0		\$0		\$0
	Revenue Accounting Adjustment	\$0		\$0		\$0		\$0
	Customer Bill Credits	\$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
	Income Tax Deferral Adjustments	\$0		\$0		\$0		\$0
	Unbilled	\$0		(\$1,485,000)		(\$1,485,000)	\$1,485,000	\$0
	AGA	\$0		\$5,168		\$5,168		\$5,168
	<b>Total Residential</b>	<b>(\$4,865,957)</b>	<b>(\$1,359,796)</b>	<b>\$648,588,195</b>	<b>(\$19,894,626)</b>	<b>\$628,693,569</b>	<b>(\$15,172,332)</b>	<b>\$613,521,236</b>
<b>Commercial</b>								
	15	(\$102,234)		\$751,031	(\$148,662)	\$602,369	\$30,554	\$632,923
	23	(\$2,276,824)	(\$848,240)	\$115,095,840	(\$1,024,198)	\$114,071,642	(\$4,271,707)	\$109,799,935
	28	(\$4,724,774)	(\$1,073,910)	\$163,342,866	(\$7,724,076)	\$155,618,790	(\$2,644,988)	\$152,973,802
	30	(\$1,769,929)	(\$507,841)	\$80,682,324	(\$3,010,104)	\$77,672,220	\$2,522,018	\$80,194,238
	47	\$47,993		\$3,264,339	(\$124,335)	\$3,140,004	\$41,109	\$3,181,113
	48	\$7,193,549	(\$750,127)	\$105,228,955	(\$7,540,973)	\$97,687,982	\$43,694,976	\$141,382,958
	54	(\$25,482)		\$101,166	(\$8,113)	\$93,053	(\$11,418)	\$81,635
	BPA Balancing Account	\$0		\$0		\$0		\$0
	Solar Feed-In Revenue	\$0		\$0		\$0		\$0
	Gain on Sale of Asset	\$0		\$0		\$0		\$0
	Revenue Accounting Adjustment	\$0		\$0		\$0		\$0
	Customer Bill Credits	\$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
	Income Tax Deferral Adjustments	\$0		\$0		\$0		\$0
	Unbilled	\$0		\$9,873,000		\$9,873,000	(\$9,873,000)	\$0
	AGA	\$0		\$3,232,134		\$3,232,134		\$3,232,134
	<b>Total Commercial</b>	<b>(\$1,657,701)</b>	<b>(\$3,180,119)</b>	<b>\$481,571,654</b>	<b>(\$19,580,460)</b>	<b>\$461,991,194</b>	<b>\$29,487,544</b>	<b>\$491,478,738</b>
<b>Industrial</b>								
	15	(\$3,783)		\$25,863	(\$6,543)	\$19,320	\$1,842	\$21,162
	23	(\$36,663)	\$0	\$1,985,640	(\$16,168)	\$1,969,472	(\$157,753)	\$1,811,719
	28	(\$208,323)	\$0	\$7,693,210	(\$384,882)	\$7,308,328	(\$396,887)	\$6,911,441
	30	(\$303,856)		\$15,457,676	(\$448,939)	\$15,008,737	(\$1,006,476)	\$14,002,261
	47	\$9,140		\$904,273	(\$27,126)	\$877,147	(\$84,391)	\$792,756
		\$5,375,544		\$89,985,461	(\$1,692,424)	\$88,293,037	(\$8,314,652)	\$79,978,385
	BPA Balancing Account	\$0		\$0		\$0		\$0
	Solar Feed-In Revenue	\$0		\$0		\$0		\$0
	Gain on Sale of Asset	\$0		\$0		\$0		\$0
	Revenue Accounting Adjustment	\$0		\$0		\$0		\$0
	Customer Bill Credits	\$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
	Income Tax Deferral Adjustments	\$0		\$0		\$0		\$0
	Unbilled	\$0		\$1,390,000		\$1,390,000	(\$1,390,000)	\$0
	AGA	\$0		\$112,639		\$112,639		\$112,639
	<b>Total Industrial</b>	<b>\$4,832,059</b>	<b>\$0</b>	<b>\$117,554,763</b>	<b>(\$2,575,981)</b>	<b>\$114,978,782</b>	<b>(\$11,348,317)</b>	<b>\$103,630,464</b>
<b>Irrigation</b>								
	41	\$2,281,274	(\$1,283,779)	\$25,363,097	(\$295,597)	\$25,067,500	\$4,126,316	\$29,193,816
	23	\$204		\$871	(\$230)	\$641	(\$129)	\$512
	48	\$312,993	(\$95,685)	\$4,428,248	(\$290,257)	\$4,137,991	\$706,071	\$4,844,062
	BPA Balancing Account	\$0		\$0		\$0		\$0
	BPA Adjustment	\$0		\$0		\$0		\$0
	Demand Charge Accrual	(\$193,000)		\$0		\$0		\$0
	Solar Feed-In Revenue	\$0		\$0		\$0		\$0
	Gain on Sale of Asset	\$0		\$0		\$0		\$0
	Revenue Accounting Adjustment	\$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
	Income Tax Deferral Adjustments	\$0		\$0		\$0		\$0
	Unbilled	\$0		\$1,205,000		\$1,205,000	(\$1,205,000)	\$0
	AGA	\$0		\$171,083		\$171,083		\$171,083
	<b>Total Irrigation</b>	<b>\$2,401,471</b>	<b>(\$1,379,464)</b>	<b>\$31,168,299</b>	<b>(\$586,084)</b>	<b>\$30,582,215</b>	<b>\$3,627,258</b>	<b>\$34,209,473</b>
<b>Lighting</b>								
	15	(\$934)		\$8,350	(\$1,610)	\$6,740	\$482	\$7,222
	23	(\$1,270)		\$139,176	\$257	\$139,433	(\$6,354)	\$133,079
	50	(\$76,288)		\$391,246	(\$391,246)	\$0	\$0	\$0
	51	(\$916,723)		\$3,424,821	\$142,062	\$3,566,883	(\$69,325)	\$3,497,558
	52	(\$3,044)		\$17,964	(\$17,964)	\$0	\$0	\$0
	53	(\$208,107)		\$648,008	\$97,769	\$745,777	(\$89,017)	\$656,760
	Solar Feed-In Revenue	\$0		\$0		\$0		\$0
	Gain on Sale of Asset	\$0		\$0		\$0		\$0
	Revenue Accounting Adjustment	\$0		\$0		\$0		\$0
	Community Solar Revenue	\$0		\$0		\$0		\$0
	DSM	\$0		\$0		\$0		\$0
	Income Tax Deferral Adjustments	\$0		\$0		\$0		\$0
	Unbilled	\$0		(\$41,000)		(\$41,000)	\$41,000	\$0
	AGA	\$0		\$0		\$0		\$0
	<b>Total Lighting</b>	<b>(\$1,206,366)</b>	<b>\$0</b>	<b>\$4,588,564</b>	<b>(\$170,732)</b>	<b>\$4,417,833</b>	<b>(\$123,215)</b>	<b>\$4,294,618</b>
<b>TOTAL COMPANY</b>		<b>(\$496,493)</b>	<b>(\$5,919,378)</b>	<b>\$1,283,471,475</b>	<b>(\$42,807,883)</b>	<b>\$1,240,663,593</b>	<b>\$6,470,938</b>	<b>\$1,247,134,531</b>

	305 Booked Revenues	Remove Tariff Riders										Total Remove Tariff Riders	
		Remove Accounting Adjustments	Sch 98 BPA Adjust	Sch 95 Pilot Cost Adj.	104 OCAT Adjust	194 Repl. Meter Def. Adjust	Sch 195 Fed. Tax Act Adjust	Sch 198 Deer Cr. Def. Adjust	Sch 203 Renew Rsrc Def Adjust	Sch 204 OSIP Adjust	Sch 207 Com. Sol. Adjust		
<b>Residential</b>													
15	\$296,609		\$9,045	(\$20)	(\$1,355)	(\$173)	\$5,960	(\$55)	(\$78)	(\$569)	(\$59)		\$12,697
4	\$889,286,974		\$40,412,254	(\$57,704)	(\$2,696,714)	(\$457,165)	\$15,405,676	(\$403,381)	(\$288,522)	(\$2,192,765)	(\$230,817)		\$49,490,861
23	\$12,460,168		\$683,545	(\$989)	(\$56,052)	(\$7,917)	\$255,082	(\$6,518)	(\$4,946)	(\$35,613)	(\$2,968)		\$83,822
28	\$3,643,986		\$231,740	(\$450)	(\$16,454)	(\$2,644)	\$89,759	(\$2,648)	(\$2,249)	(\$16,642)	(\$1,349)		\$278,862
	(\$192,823)		\$192,823										\$192,823
BPA Balancing Account													(\$2,229,585)
Solar Feed-In Revenue	\$2,229,585	(\$2,229,585)											(\$17,372)
Gain on Sale of Asset	\$17,372												\$2,570,998
Revenue Accounting Adjustment	(\$2,570,998)												\$165,055
Customer Bill Credits	(\$165,055)		\$165,055										(\$234,155)
Community Solar Revenue	\$234,155												\$723,515
Revenue Adjustment - I&D Reserve	(\$723,515)												(\$20,507,206)
DSM	\$20,507,206	(\$20,507,206)											(\$961,736)
Blue Sky	\$961,736												(\$18,777,989)
Income Tax Deferral Adjustments	\$18,777,989	(\$18,777,989)											\$0
Unbilled	(\$1,485,000)												\$0
AGA	\$5,168												\$0
<b>Total Residential</b>	<b>\$643,283,576</b>	<b>(\$39,268,495)</b>	<b>\$41,529,406</b>	<b>(\$59,163)</b>	<b>(\$2,770,575)</b>	<b>(\$467,899)</b>	<b>\$15,756,477</b>	<b>(\$412,803)</b>	<b>(\$295,795)</b>	<b>(\$2,345,589)</b>	<b>(\$235,193)</b>		<b>\$11,530,371</b>
<b>Commercial</b>													
15	\$834,201		\$6,242	(\$63)	(\$3,596)	(\$546)	\$19,477	(\$172)	(\$253)	(\$1,835)	(\$190)		\$1,193
23	\$116,350,093		\$175,710	(\$10,650)	(\$497,008)	(\$81,855)	\$2,820,634	(\$67,410)	(\$53,251)	(\$383,408)	(\$31,951)		\$1,870,811
28	\$168,712,986		\$423,697	(\$18,008)	(\$711,095)	(\$109,340)	\$3,312,799	(\$117,748)	(\$94,539)	(\$693,597)	(\$56,723)		\$2,428,563
30	\$81,751,815		\$270,010	(\$10,718)	(\$346,449)	(\$55,752)	\$1,887,845	(\$53,044)	(\$53,592)	(\$385,864)	(\$32,155)		\$1,208,280
47	\$3,198,340		\$0	(\$276)	(\$13,490)	(\$1,110)	\$45,255	(\$1,312)	(\$1,382)	(\$8,847)	(\$829)		\$18,006
48	\$97,335,107		\$50,290	(\$17,771)	(\$415,426)	(\$72,515)	\$2,618,943	(\$85,699)	(\$75,126)	(\$524,093)	(\$49,134)		\$1,429,426
54	\$124,979		\$0	(\$13)	(\$529)	(\$75)	\$2,664	(\$38)	(\$38)	(\$275)	(\$26)		\$1,569
	\$3,623		(\$3,623)										(\$3,623)
BPA Balancing Account													(\$1,982,204)
Solar Feed-In Revenue	\$1,982,204	(\$1,982,204)											(\$16,222)
Gain on Sale of Asset	\$16,222												(\$1,014,355)
Revenue Accounting Adjustment	(\$1,014,355)	(\$1,014,355)											\$20,212
Customer Bill Credits	(\$20,212)												(\$169,681)
Community Solar Revenue	\$169,681	(\$169,681)											(\$19,898)
Other Customer Retail Rev	\$19,898												\$550,246
Revenue Adjustment - I&D Reserve	(\$550,246)												(\$12,360,688)
DSM	\$12,360,688	(\$12,360,688)											(\$1,059,754)
Blue Sky	\$1,059,754												(\$17,786,169)
Income Tax Deferral Adjustments	\$17,786,169	(\$17,786,169)											\$0
Unbilled	\$9,873,000												\$0
AGA	\$3,232,134												\$0
<b>Total Commercial</b>	<b>\$513,275,771</b>	<b>(\$33,838,492)</b>	<b>\$822,285</b>	<b>(\$58,400)</b>	<b>(\$1,987,587)</b>	<b>(\$321,193)</b>	<b>\$11,207,616</b>	<b>(\$337,425)</b>	<b>(\$278,183)</b>	<b>(\$2,003,909)</b>	<b>(\$171,008)</b>		<b>(\$26,866,297)</b>
<b>Industrial</b>													
15	\$29,129		\$12	(\$2)	(\$124)	(\$21)	\$746	(\$7)	(\$10)	(\$71)	(\$7)		\$517
23	\$1,953,674		\$946	(\$180)	(\$5,489)	(\$1,418)	\$46,949	(\$1,168)	(\$999)	(\$5,473)	(\$539)		\$28,628
28	\$7,815,407		\$640	(\$817)	(\$33,282)	(\$4,664)	\$166,027	(\$5,022)	(\$4,084)	(\$30,221)	(\$2,450)		\$86,126
30	\$15,624,654		\$0	(\$1,767)	(\$66,763)	(\$9,556)	\$303,874	(\$11,149)	(\$8,836)	(\$63,621)	(\$5,302)		\$136,881
47	\$868,001		\$0	(\$22)	(\$3,792)	(\$159)	\$2,186	(\$188)	(\$112)	(\$714)	(\$67)		\$2,969
48	\$83,686,167		\$0	(\$13,038)	(\$593,201)	(\$63,055)	\$1,939,088	(\$74,519)	(\$65,189)	(\$417,213)	(\$39,114)		\$83,759
	\$51		(\$51)										(\$51)
Solar Feed-In Revenue	\$554,274	(\$554,274)											(\$54,274)
Gain on Sale of Asset	\$4,791	(\$4,791)											(\$4,791)
Revenue Accounting Adjustment	(\$489,343)	(\$489,343)											\$489,343
Customer Bill Credits	(\$3,613)		\$3,613										\$3,613
Community Solar Revenue	\$47,336	(\$47,336)											(\$47,336)
Revenue Adjustment - I&D Reserve	(\$179,951)												\$179,951
DSM	\$949,796	(\$949,796)											(\$949,796)
Blue Sky	\$581,738												(\$581,738)
Income Tax Deferral Adjustments	\$5,574,970	(\$5,574,970)											(\$5,574,970)
Unbilled	\$1,390,000												\$0
AGA	\$112,639												\$0
<b>Total Industrial</b>	<b>\$118,599,710</b>	<b>(\$7,039,999)</b>	<b>\$1,547</b>	<b>(\$15,826)</b>	<b>(\$465,651)</b>	<b>(\$78,873)</b>	<b>\$2,458,771</b>	<b>(\$92,053)</b>	<b>(\$79,130)</b>	<b>(\$518,312)</b>	<b>(\$47,479)</b>		<b>(\$5,877,007)</b>
<b>Irrigation</b>													
41	\$22,908,896		\$927,696	(\$2,350)	(\$104,363)	(\$14,200)	\$766,717	(\$11,044)	(\$11,749)	(\$86,942)	(\$7,049)		\$1,456,716
23	\$663		\$0	(\$0)	(\$2)	(\$0)	\$9	(\$0)	(\$0)	(\$0)	(\$0)		\$4
48	\$3,864,294		\$262,248	(\$589)	(\$17,044)	(\$725)	\$127,156	(\$857)	(\$2,943)	(\$18,835)	(\$1,786)		\$340,646
	\$76,703		(\$76,703)										(\$76,703)
BPA Balancing Account													(\$272,963)
BPA Adjustment	\$272,963		(\$272,963)										\$0
Demand Charge Accrual	\$193,000												(\$72,078)
Solar Feed-In Revenue	\$72,078	(\$72,078)											(\$116)
Gain on Sale of Asset	\$116												\$75,223
Revenue Accounting Adjustment	(\$75,223)												(\$8,305)
Community Solar Revenue	\$8,305	(\$8,305)											\$51,031
Revenue Adjustment - I&D Reserve	(\$51,031)												(\$773,574)
DSM	\$773,574	(\$773,574)											(\$518)
Blue Sky	\$518	(\$518)											(\$1,001,106)
Income Tax Deferral Adjustments	\$1,001,106	(\$1,001,106)											\$0
Unbilled	\$1,205,000												\$0
AGA	\$171,083												\$0
<b>Total Irrigation</b>	<b>\$30,442,034</b>	<b>(\$1,749,442)</b>	<b>\$840,278</b>	<b>(\$2,938)</b>	<b>(\$121,409)</b>	<b>(\$14,925)</b>	<b>\$893,882</b>	<b>(\$11,902)</b>	<b>(\$14,692)</b>	<b>(\$105,778)</b>	<b>(\$8,815)</b>		<b>(\$295,742)</b>
<b>Lighting</b>													
15	\$9,118		\$62	(\$1)	(\$39)	(\$5)	\$170	(\$2)	(\$2)	(\$16)	(\$2)		\$166
23	\$139,943		\$0	(\$6)	(\$611)	(\$51)	\$1,473	(\$42)	(\$30)	(\$215)	(\$18)		\$502
50	\$453,624		\$0	(\$35)	(\$1,852)	(\$0)	\$16,809	(\$105)	(\$89)	(\$70)	(\$70)		\$13,908
51	\$4,287,037		\$0	(\$230)	(\$13,326)	(\$2,728)	\$87,000	(\$711)	(\$1,151)	(\$8,747)	(\$691)		\$54,036
52	\$20,380		\$0	(\$8)	(\$83)	(\$5)	\$761	(\$0)	(\$3)	(\$30)	(\$4)		\$628
53	\$843,364		\$0	(\$114)	(\$3,611)	(\$469)	\$18,964	(\$313)	(\$227)	(\$1,365)	(\$114)		\$12,750
	\$12,836		(\$12,836)										(\$12,836)
Solar Feed-In Revenue		(\$12,836)											(\$834)
Gain on Sale of Asset	\$834												\$12,537
Revenue Accounting Adjustment	(\$12,537)		\$12,537										(\$894)
Community Solar Revenue	\$894												\$137,330
DSM	\$137,330	(\$137,330)											(\$130,222)
Income Tax Deferral Adjustments	\$130,222	(\$130,222)											(\$41,000)
Unbilled	(\$41,000)												\$0
AGA	\$0												\$0
<b>Total Lighting</b>	<b>\$5,982,047</b>	<b>(\$269,580)</b>	<b>\$62</b>	<b>(\$387)</b>	<b>(\$24,522)</b>	<b>(\$3,251)</b>	<b>\$125,267</b>	<b>(\$1,067)</b>	<b>(\$1,521)</b>	<b>(\$11,221)</b>	<b>(\$898)</b>		<b>(\$187,116)</b>
<b>TOTAL COMPANY</b>	<b>\$1,311,583,139</b>	<b>(\$82,166,008)</b>	<b>\$43,293,578</b>	<b>(\$136,715)</b>	<b>(\$5,369,744)</b>	<b>(\$886,141)</b>	<b>\$30,442,013</b>	<b>(\$855,250)</b>	<b>(\$669,321)</b>	<b>(\$4,884,809)</b>	<b>(\$463,394)</b>		



**PacifiCorp  
Oregon General Rate Case - December 2023  
REC Revenue**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Revenue:</b>							
Remove:							
June 2021 Booked Revenues (Including Accruals)	456	1	(9,033,788)	SG	26.070%	(2,355,140)	3.2.1
June 2021 REC Deferrals	456	1	2,739,416	SG	26.070%	714,175	3.2.1
June 2021 Leaning Juniper Indemnity	456	1	(385)	SG	26.070%	(100)	3.2.1

**Description of Adjustment:**

This adjustment removes all REC revenues as booked during the 12 months ended June 2021. 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. This adjustment also removes REC Deferrals from the 12 months ended June 2021.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**REC Revenue**  
**Actuals as Booked**

Posting Date	Fin Accrual	Fin Reversal	Back Office Actual	SAP Total
FERC Acct (Ref B1)	4562700	4562700	4562700	
SAP Acct	301944	301944	301945	
July-20	(56,390)	83,750	(90,140)	(62,780)
August-20	(50,000)	56,390	(50,000)	(43,610)
September-20	(50,000)	50,000	(50,000)	(50,000)
October-20	(666,500)	50,000	(60,596)	(677,096)
November-20	(6,170,733)	4,085,633	(666,500)	(2,751,600)
December-20	(293,750)	2,751,600	(2,751,600)	(293,750)
January-21	(1,570,611)	293,750	(293,750)	(1,570,611)
February-21	(50,000)	1,570,611	(1,570,611)	(50,000)
March-21	(100,750)	50,000	(199,000)	(249,750)
April-21	(2,421,588)	100,750	(418,435)	(2,739,273)
May-21	(261,194)	2,421,588	(2,421,587)	(261,194)
June-21	(233,500)	261,194	(311,819)	(284,125)
<b>12 ME June 2021 Total</b>	<b>(11,925,016)</b>	<b>11,775,266</b>	<b>(8,884,038)</b>	<b>(9,033,788)</b>

**Ref 3.2**

**REC Deferrals Included in Unadjusted Results:**

FERC Account 4562700  
Amount 12 ME June 2021 **2,739,416 Ref 3.2**

**Leaning Juniper indemnity revenue included in Unadjusted Results:**

FERC Account 4562700  
Amount 12 ME June 2021 **(385) Ref 3.2**



**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Wheeling Revenue**

PAGE 3.3

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Revenue:</b>							
Other Electric Revenues	456	1	1,427,746	SG	26.070%	372,218	3.3.1
Other Electric Revenues	456	2	(480,136)	SG	26.070%	(125,173)	3.3.1
Other Electric Revenues	456	3	30,756,795	SG	26.070%	8,018,402	3.3.1
			<u>31,704,404</u>				
<b>Adjustment Detail:</b>							
Actual Wheeling Revenues 12 ME June 2021			129,760,988				3.3.1
Total Adjustments			<u>31,704,404</u>				Above
Adjusted Wheeling Revenues 12 ME December 2023			<u>161,465,392</u>				3.3.1

**Description of Adjustment:**

This adjustment removes out-of-period and one-time adjustments from wheeling revenues recorded in 12 months ended June 2021 and adds in pro forma changes through December 2023.

Customer	Total
3 Phases Renewables, Inc.	(5,267)
Airport Solar LLC	(2,069,560)
Arizona Electric Power Co-op	(44)
Avangrid Renewables, LLC	(6,075,505)
BASIN ELECTRIC POWER COOPERATIVE	(765,890)
BLACK HILLS POWER & LIGHT COMPANY	(3,198,151)
BONNEVILLE POWER ADMINISTRATION	(21,261,631)
Brookfield Energy Marketing L.P.	(1,091,852)
Calpine Energy Solutions, LLC	(535,370)
City of Roseville	(1,562,545)
Clatskanie PUD	(505,826)
Colorado Electric Utility Co.	(11,742)
Constellation NewEnergy, Inc.	(48,188)
CONSTELLATION POWER SOURCE, INC.	(1,832,842)
CP Energy Marketing	(11,215)
DESERET GENERATION & TRANS. CO-OP.	(5,998,739)
Dynasty Power	(2,058)
Eagle Energy Partners I LP	(367,177)
EDP Renewables North American LLC	(178,149)
Enel Trading North America	(43,216)
Energy Keepers, Inc.	(235,207)
Eugene Water & Electric Board	(470)
Evergreen BioPower	(374,092)
FALL RIVER RURAL ELECTRIC COOPERATI	(151,308)
Falls Creek H.P., LP	(154,706)
Guzman Energy	(734,723)
Idaho Power Co. Balancing Ops	(909,216)
Imperial Irrigation District	(151,038)
Intermountain Renewable(Cyrq Enrgy)	(415,535)
LH Garrett	(406,288)
Macquarie Energy LLC	(437,870)
MAG Energy Solutions Inc.	(96,911)
Mercuria Energy	(280,451)
Moon Lake Electric Association	(20,424)
MORGAN STANLEY CAPITAL	(6,000,024)
Navajo Tribal Utility Authority	(85,361)
NextEra Energy Resources, LLC	(3,846,724)
Obsidian Renewables, LLC	(7,000)
PACIFIC GAS & ELECTRIC COMPANY	(54,519)
PACIFICORP	-
PORTLAND GENERAL ELECTRIC COMPANY	(4)
POWEREX	(22,953,818)
RAINBOW ENERGY MARKETING CORPORATIO	(1,067,691)
Sacramento Municipal Utility Dist	(639,955)
Salt River Project	(866,969)
Shell Energy NA (Coral Power)	(5,034,768)
SIERRA PACIFIC POWER COMPANY	(33,146)
So. Cal Public Power Authority	(47,733)
Southern California Edison Company	(3,930,368)
State of South Dakota	(134,729)
TEC Energy	(1,145)
Tenaska Power Services Company	(519,215)
The Energy Authority	(138,922)
TRANSALTA ENERGY MARKETING CORP.	(1,333,310)
TRI-STATE GEN. & TRANS. ASSOCIATION	(626,607)
U.S. Bureau of Reclamation	(64,348)
UTAH ASSOCIATED MUNICIPAL POWER SYS	(19,470,100)
UTAH MUNICIPAL POWER AGENCY	(2,695,108)
Warm Springs Power Enterprises	(119,700)
WESTERN AREA POWER ADMIN. - UT	(3,243,301)
WESTERN AREA POWER ADMINISTRATION	(91,449)
Cowlitz Revenue	(185,531)
Accruals and Adjustments	(6,636,239)

**Total** (129,760,988)

Ref 3.3

Type

1	Remove refunds and other out of period adjustments*	(1,427,746)
2	BPA WEID Network Annualization*	(2,332)
2	BPA Green Springs Conversion to Network Service*	482,468
3	New Powerex Contracts 1016 and 1017*	(7,936,950)
3	EDP Renewable Contracts	(2,631,332)
3	Forecasted Price/Volume Increase Network	(20,188,513)

**Incremental Adjustments** (31,704,404)

Ref 3.3

**Accum Totals** (161,465,392)

Ref 3.3

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Ancillary Revenues**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Revenues:</b>							
Ancillary Contract Renewal	456	1	(10,541,483)	SG	26.070%	(2,748,201)	3.4.1

**Description of Adjustment:**

This adjustment includes ancillary revenue contract changes that are included in the net power cost study.

**PacifiCorp  
Oregon General Rate Case - December 2023  
Ancillary Services Revenue**

<b>Description</b>	<b>12 Months Ended</b>	<b>12 Months</b>	<b>Incremental</b>	<b>FERC Acct</b>	<b>Factor</b>	<b>Ref</b>
	<b>June 2021</b>	<b>Ending</b>				
		<b>December 2023</b>				
BPA Foote Creek 4 Ancillary Service	136,182	-	(136,182)	456	SG	
SCL Stateline Demand & Energy	10,405,301	-	(10,405,301)	456	SG	
	<b>10,541,483</b>	<b>-</b>	<b>(10,541,483)</b>			3.4

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Fly Ash Revenue**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Revenues:</b>							
Ash Sales Revenue	456	2	3,177,631	SG	26.070%	828,419	Below

**Adjustment Detail:**

12 Months Ended June 2021	12,187,273
12 Months under New Contract Terms	15,364,905
Adjustment	<u>3,177,631</u>

**Description of Adjustment:**

The recently executed contract for fly ash from Jim Bridger plant resulted in an increase to ash sales revenues starting in October 2020. This adjustment normalizes the revenue to an annualized basis on the new contract terms.

## Tab 4 - Operation & Maintenance Expense

**PacifiCorp**  
**Oregon General Rate Case – December 2023**  
**Operation & Maintenance Expense Adjustment Index**

The Company's June 2021 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 2023 test period. The following adjustments are included:

- 4.1 Miscellaneous General Expenses & Revenues
- 4.2 Wages & Employee Benefits
- 4.3 Pension Related Non-Service Expense
- 4.4 Remove Non-Recurring Entries
- 4.5 Insurance Expense
- 4.6 Generation Overhaul Expense
- 4.7 Revenue Sensitive Items & Uncollectible Expense
- 4.8 Membership & Subscriptions
- 4.9 Meals and Entertainment Adjustment
- 4.10 O&M Escalation
- 4.11 Vegetation & Wildfire Management O&M
- 4.12 Transmission Wheeling - Facebook

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Tab 4 Adjustment Summary**

	Total Adjustments	4.1 Miscellaneous General Expenses & Revenues	4.2 Wage & 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
1 Operating Revenues:							
2 General Business Revenues	1,766,619	1,766,619	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-	-
6 Total Operating Revenues	1,766,619	1,766,619	-	-	-	-	-
7							
8 Operating Expenses:							
9 Steam Production	5,165,696	-	1,607,904	-	-	-	148,346
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	(7,806,503)	-	338,845	-	(8,603,213)	-	-
12 Other Power Supply	2,779,918	(654)	609,267	-	-	-	824,755
13 Transmission	155,610	-	501,704	-	-	-	-
14 Distribution	28,356,724	-	2,789,657	-	-	-	-
15 Customer Accounting	1,470,447	(14,359)	555,165	-	-	-	-
16 Customer Service & Info	418,878	22,789	178,313	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	(25,183,567)	347,261	815,733	609,110	-	(27,897,466)	-
19							
20 Total O&M Expenses	5,357,203	355,037	7,396,589	609,110	(8,603,213)	(27,897,466)	973,101
21							
22 Depreciation	-	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-	-
24 Taxes Other Than Income	(1,473,948)	-	-	-	-	-	-
25 Income Taxes - Federal	1,450,480	262,240	(1,482,986)	(122,124)	1,724,909	7,488,960	(195,103)
26 Income Taxes - State	328,494	59,390	(335,855)	(27,658)	390,644	1,696,042	(44,185)
27 Income Taxes - Def Net	(2,473,765)	-	-	-	-	(2,473,765)	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	102,338	102,338	-	-	-	-	-
30							
31 Total Operating Expenses:	3,290,802	779,004	5,577,748	459,328	(6,487,660)	(21,186,229)	733,813
32							
33 Operating Rev For Return:	(1,524,183)	987,615	(5,577,748)	(459,328)	6,487,660	21,186,229	(733,813)
34							
35 Rate Base:							
36 Electric Plant In Service	-	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-
44 Working Capital	53,519	6,396	52,721	4,342	(61,321)	(176,870)	6,936
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	53,519	6,396	52,721	4,342	(61,321)	(176,870)	6,936
49							
50 Rate Base Deductions:							
51 Accum Prov For Deprec	-	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	(9,430,521)	-	-	-	-	(9,430,521)	-
54 Unamortized ITC	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	38,356,344	-	-	-	-	38,356,344	-
58							
59 Total Rate Base Deductions	28,925,824	-	-	-	-	28,925,824	-
60							
61 Total Rate Base:	28,979,343	6,396	52,721	4,342	(61,321)	28,748,953	6,936
62							
63 Return on Rate Base	-0.065%	0.021%	-0.117%	-0.010%	0.136%	0.407%	-0.015%
64							
65 Return on Equity	-0.125%	0.040%	-0.223%	-0.018%	0.260%	0.779%	-0.029%
66							
67 TAX CALCULATION:							
68 Operating Revenue	(2,218,974)	1,309,244	(7,396,589)	(609,110)	8,603,213	27,897,466	(973,101)
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	606,921	1,094	1,102	91	(1,282)	601,144	145
72 Schedule "M" Additions	10,061,436	-	-	-	-	10,061,436	-
73 Schedule "M" Deductions	-	-	-	-	-	-	-
74 Income Before Tax	7,235,540	1,308,151	(7,397,692)	(609,201)	8,604,495	37,357,758	(973,246)
75							
76 State Income Taxes	328,494	59,390	(335,855)	(27,658)	390,644	1,696,042	(44,185)
77 Taxable Income	6,907,046	1,248,761	(7,061,836)	(581,543)	8,213,851	35,661,716	(929,060)
78							
79 Federal Income Taxes + Other	1,450,480	262,240	(1,482,986)	(122,124)	1,724,909	7,488,960	(195,103)
APPROXIMATE PRICE CHANGE	4,983,679	(1,353,743)	7,650,024	629,981	(8,897,991)	(26,195,834)	1,006,443



**Pacificorp**  
**Oregon General Rate Case - December 202:**  
**Tab 4 Adjustment Summary**

	4.7	4.8	4.9	4.10	4.11	4.12
	Revenue Sensitive Items & Uncollectible Expense	Memberships and Subscriptions	Meals and Entertainment Adjustment	O&M Expense Escalation	Veg. & Wildfire Management O&M	Transmission Wheeling Facebook
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	-	-	(433)	3,409,878	-	-
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	-	-	(579)	458,444	-	-
12 Other Power Supply	-	-	(4,347)	1,350,898	-	-
13 Transmission	-	-	(270)	593,817	296,925	(1,236,567)
14 Distribution	-	-	(8,751)	(482,130)	26,057,949	-
15 Customer Accounting	(274,522)	-	(260)	1,204,424	-	-
16 Customer Service & Info	-	-	(3,405)	221,181	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	(227,655)	(146,082)	(2,625)	1,318,158	-	-
19						
20 Total O&M Expenses	(502,178)	(146,082)	(20,671)	8,074,669	26,354,874	(1,236,567)
21	-	-	-	-	-	-
22 Depreciation	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-
24 Taxes Other Than Income	(1,473,948)	-	-	-	-	-
25 Income Taxes - Federal	396,205	29,289	4,144	(1,618,938)	(5,284,044)	247,927
26 Income Taxes - State	89,729	6,633	939	(366,645)	(1,196,690)	56,149
27 Income Taxes - Def Net	-	-	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-
30						
31 Total Operating Expenses:	(1,490,191)	(110,160)	(15,588)	6,089,087	19,874,141	(932,492)
32						
33 Operating Rev For Return:	1,490,191	110,160	15,588	(6,089,087)	(19,874,141)	932,492
34						
35 Rate Base:						
36 Electric Plant In Service	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-
44 Working Capital	(14,085)	(1,041)	(147)	57,554	187,850	(8,814)
45 Weatherization Loans	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	(14,085)	(1,041)	(147)	57,554	187,850	(8,814)
49	-	-	-	-	-	-
50 Rate Base Deductions:						
51 Accum Prov For Deprec	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-
53 Accum Def Income Tax	-	-	-	-	-	-
54 Unamortized ITC	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-
58						
59 Total Rate Base Deductions	-	-	-	-	-	-
60						
61 Total Rate Base:	(14,085)	(1,041)	(147)	57,554	187,850	(8,814)
62						
63 Return on Rate Base	0.031%	0.002%	0.000%	-0.127%	-0.413%	0.019%
64						
65 Return on Equity	0.059%	0.004%	0.001%	-0.242%	-0.791%	0.037%
66						
67 TAX CALCULATION:						
68 Operating Revenue	1,976,126	146,082	20,671	(8,074,669)	(26,354,874)	1,236,567
69 Other Deductions	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-
71 Interest	(295)	(22)	(3)	1,203	3,928	(184)
72 Schedule "M" Additions	-	-	-	-	-	-
73 Schedule "M" Deductions	-	-	-	-	-	-
74 Income Before Tax	1,976,420	146,104	20,674	(8,075,873)	(26,358,802)	1,236,751
75						
76 State Income Taxes	89,729	6,633	939	(366,645)	(1,196,690)	56,149
77 Taxable Income	1,886,691	139,470	19,735	(7,709,228)	(25,162,113)	1,180,603
78						
79 Federal Income Taxes + Other	396,205	29,289	4,144	(1,618,938)	(5,284,044)	247,927
APPROXIMATE PRICE CHANGE	(2,062,074)	(151,053)	(21,374)	8,393,354	27,265,227	(1,279,281)

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Miscellaneous General Expense & Revenue**

PAGE 4.1

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Revenue:</b>							
Gain on Property Sales	421	1	2,241,588	SO	27.173%	609,109	
Gain on Property Sales	421	1	(1,947,042)	SG	26.070%	(507,601)	
Gain on Property Sales	421	1	830	OR	Situs	830	
Gain on Property Sales	421	1	(65,100)	UT	Situs	-	
			<u>230,276</u>			<u>102,338</u>	4.1.1
Commercial and Industrial	442	1	1,766,619	OR	Situs	1,766,619	4.1.2
<b>Adjustment to Expense:</b>							
Other Expenses	557	1	(2,509)	SG	26.070%	(654)	
Administrative & General Salaries	920	1	-	SO	27.173%	-	
Office Supplies and Expenses	921	1	1,284,000	SO	27.173%	348,902	
Customer Records	903	1	-	CN	30.990%	-	
Customer Records	903	1	(14,359)	OR	Situs	(14,359)	
Informational Advertising	909	1	19,017	CA	Situs	-	
Informational Advertising	909	1	(73,991)	CN	30.990%	(22,930)	
Informational Advertising	909	1	1,052	ID	Situs	-	
Informational Advertising	909	1	45,719	OR	Situs	45,719	
Informational Advertising	909	1	11,080	UT	Situs	-	
Informational Advertising	909	1	10,746	WA	Situs	-	
Regulatory Commission Expense	928	1	(2,373)	OR	Situs	(2,373)	
Regulatory Commission Expense	928	1	2,373	SO	27.173%	645	
Duplicate Charges	929	1	317	SO	27.173%	86	
Duplicate Booking Reversal	431	1	3,750	SNP	25.599%	960	
			<u>1,284,821</u>			<u>355,996</u>	4.1.1
Total Adjustments			<u>3,281,716</u>			<u>2,224,954</u>	

**Description of Adjustment:**

This adjustment removes certain miscellaneous expenses that should have been charged below-the-line to non-regulated expenses. It also reallocates certain items such as gains and losses on property sales and regulatory commission expense to reflect the appropriate allocation among the Company's jurisdictions. In addition, it recognizes revenues from the Oregon Customer Opt-Out amortization.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Miscellaneous General Expense & Revenue**

<b>Description</b>	<b>FERC</b>	<b>Factor</b>	<b>Code</b>	<b>Adjustment</b>	
<b>FERC 421 - (Gain)/Loss on Sale of Utility Plant</b>					
Gain on Property Sales	421	SO	421SO	2,241,588	
Gain on Property Sales	421	SG	421SG	(1,947,042)	
Gain on Property Sales	421	OR	421OR	830	
Gain on Property Sales	421	UT	421UT	(65,100)	
				<u>230,276</u>	<b>Ref 4.1</b>
<b>Non-Regulated Flights</b>					
Other Expenses	557	SG	557SG	(2,509)	
Office Supplies and Expenses	921	SO	921SO	(14,770)	
				<u>(17,279)</u>	
<b>Regulatory Commission Expenses</b>					
Remove transmission costs from Situs allocation	928	OR	928OR	(2,373)	
Assign transmission costs to system allocation	928	SO	928SO	2,373	
Removal of duplicated entry	431	SNP	431SNP	3,750	
				<u>3,750</u>	
<b>Credit Facility Fee Adjustment</b>					
Reallocate credit facility fees interest expense	921	SO	921SO	1,313,469	
<b>FERC 909 - Informational &amp; Instructional Advertising</b>					
Blue Sky	909	CN	909CN	4,970	
Blue Sky	909	OR	909OR	9,072	
Blue Sky	903	OR	903OR	(14,359)	
Blue Sky	929	SO	929SO	317	
Giving Campagin	909	CN	909CN	(420)	
Remove system allocation	909	CN	909CN	(78,541)	
Remove Situs allocation	909	UT	909UT	(1,052)	
Add situs allocation	909	ID	909ID	1,052	
Add situs allocation	909	UT	909UT	12,132	
Add situs allocation	909	WA	909WA	10,746	
Add situs allocation	909	CA	909CA	19,017	
Add situs allocation	909	OR	909OR	36,647	
Total				<u>(420)</u>	
<b>FERC 921 - Office Supplies &amp; Expenses</b>					
Expense removal	921	SO	921SO	(14,699)	
				<u>(14,699)</u>	
<b>TOTAL MISC GENERAL EXPENSE REMOVED</b>				<u><u>1,284,821</u></u>	<b>Ref. 4.1</b>

**PacifiCorp  
 Oregon General Rate Case - December 2023  
 Miscellaneous General Expense & Revenue**

**Revenues that need to be included in results:**

	Five-year Opt Out Amortization	Total	Account	Factor	
Residential	-	-	<b>440</b>	<b>OR</b>	<b>Ref 4.1</b>
Commercial & Industrial	1,766,619	<b>1,766,619</b>	<b>442</b>	<b>OR</b>	<b>Ref 4.1</b>
Street & Highway Lighting	-	-	<b>444</b>	<b>OR</b>	<b>Ref 4.1</b>
	<u>1,766,619</u>	<u><b>1,766,619</b></u>			

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Wages & Employee Benefits**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Steam Operations	500	3	3,466,582	SG	26.070%	903,750	
Fuel Related-Non NPC	501	3	4,907	SE	25.068%	1,230	
Steam Maintenance	512	3	2,696,262	SG	26.070%	702,925	
Hydro Operations	535	3	671,585	SG-P	26.070%	175,085	
Hydro Operations	535	3	457,495	SG-U	26.070%	119,271	
Hydro Maintenance	545	3	139,850	SG-P	26.070%	36,459	
Hydro Maintenance	545	3	30,805	SG-U	26.070%	8,031	
Other Operations	548	3	550,440	SG	26.070%	143,502	
Other Operations	549	3	1,049	OR	Situs	1,049	
Other Maintenance	553	3	177,568	SG	26.070%	46,293	
Other Power Supply Expenses	557	3	1,604,981	SG	26.070%	418,424	
Other Power Supply Expenses	557	3	3,804	ID	Situs	-	
Transmission Operations	560	3	1,179,760	SG	26.070%	307,568	
Transmission Maintenance	571	3	744,666	SG	26.070%	194,137	
Distribution Operations	580	3	1,273,155	SNPD	26.473%	337,037	
Distribution Operations	580	3	1,392,339	OR	Situs	442,491	
Distribution Maintenance	593	3	279,910	SNPD	26.473%	74,099	
Distribution Maintenance	593	3	5,425,914	OR	Situs	1,936,029	
Customer Accounts	903	3	1,488,711	CN	30.990%	461,350	
Customer Accounts	903	3	634,906	OR	Situs	93,815	
Customer Services	908	3	197,890	CN	30.990%	61,326	
Customer Services	908	3	1,832	OTHER	0.000%	-	
Customer Services	908	3	343,834	OR	Situs	116,987	
Administrative & General	920	3	2,642,026	SO	27.173%	717,920	
Administrative & General	920	3	236,721	OR	Situs	66,422	
Administrative & General	935	3	113,501	SO	27.173%	30,842	
Administrative & General	935	3	1,027	OR	Situs	549	
			<u>25,761,520</u>			<u>7,396,589</u>	4.2.2

**Description of Adjustment:**

This adjustment recognizes wage and benefit increases that have occurred, or are projected to occur during the twelve month period ending December 2023 for labor charged to operation & maintenance accounts. See page 4.2.1 for more information on how this adjustment was calculated.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Wage and Employee Benefit Adjustment**

The unadjusted, annualized (12 months ended June 2021), and pro forma period (12 months ending December 2023) labor expenses are summarized on page 4.2.2. The following is an explanation of the procedures used to develop the labor benefits & expenses used in this adjustment.

1. Actual June 2021 total labor related expenses are identified on page 4.2.2, including bare labor, incentive, other labor, pensions, benefits, and payroll taxes.
2. Actual June 2021 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 4.2.4.
3. The annualized June 2021 regular time, overtime, and premium pay expenses were then escalated prospectively by labor group to December 2023 (see page 4.2.3). Union and non-union costs were escalated using the contractual and target rates found on page 4.2.4 and 4.2.5.
4. Compensation related to the Annual Incentive Plan (AIP) is included after removing Named Executive Officers (NEO's) and one-half of remaining AIP 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.
5. Pro Forma December 2023 pension and employee benefit expenses are based on either actuarial projections or are calculated by using actual June 2021 data escalated to December 2023. These expenses can be found on page 4.2.7.
6. Payroll tax calculations can be found on page 4.2.8.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Wage and Employee Benefit Adjustment**

Account	Description	Actual 12 Months Ended June 2021	Pro Forma 12 Months Ending December 2023	Adjustment	Ref.
5001XX	Regular Ordinary Time	435,272,685	465,243,401	29,970,717	
5002XX	Overtime	78,873,805	84,304,664	5,430,859	
5003XX	Premium Pay	12,492,242	13,352,395	860,154	
	<b>Subtotal for Escalation</b>	<b>526,638,732</b>	<b>562,900,461</b>	<b>36,261,729</b>	4.2.3_5
5005XX	Unused Leave Accrual	3,238,340	3,461,316	222,976	4.2.6
500600	Temporary/Contract Labor	-	-	-	
500700	Severance Pay	2,823,587	324,311	(2,499,276)	
500850	Other Salary/Labor Costs	3,664,315	3,664,315	-	
50109X	Joint Owner Cutbacks	(1,116,081)	(1,192,928)	(76,848)	4.2.6
	<b>Subtotal Bare Labor</b>	<b>535,248,894</b>	<b>569,157,475</b>	<b>33,908,581</b>	
500410	Annual Incentive Plan	19,621,442	16,886,838	(2,734,605)	4.2.6
	<b>Total Incentive</b>	<b>19,621,442</b>	<b>16,886,838</b>	<b>(2,734,605)</b>	
500250	Overtime Meals	1,547,581	1,547,581	-	
50040x	Bonus and Awards	5,912,567	5,912,567	-	4.2.6
501325	Physical Exam	72,102	72,102	-	
502300	Education Assistance	155,719	155,719	-	
580899	Mining Salary/Benefit Credit	(188,725)	(188,725)	-	
	<b>Total Other Labor</b>	<b>7,499,244</b>	<b>7,499,244</b>	<b>-</b>	
	<b>Subtotal Labor and Incentive</b>	<b>562,369,581</b>	<b>593,543,557</b>	<b>31,173,977</b>	
50110X	Pensions	6,136,263	4,818,137	(1,318,127)	4.2.7
501115	SERP Plan	-	-	-	4.2.7
50115X	Post Retirement Benefits	947,520	1,821,623	874,103	4.2.7
501160	Post Employment Benefits	6,401,045	4,691,617	(1,709,428)	4.2.7
	<b>Total Pensions</b>	<b>13,484,828</b>	<b>11,331,377</b>	<b>(2,153,451)</b>	4.2.7
501102	Pension Administration	2,012,320	897,077	(1,115,243)	4.2.7
50112X	Medical	55,789,610	61,261,629	5,472,019	4.2.7
50117X	Dental	3,569,680	4,346,190	776,510	4.2.7
50120X	Vision	257,722	525,727	268,005	4.2.7
50122X	Life	818,089	874,419	56,330	4.2.7
50125X	401(k)	39,576,899	42,301,967	2,725,069	4.2.7
501251	401(k) Administration	(0)	-	0	4.2.7
501275	Accidental Death & Disability	35,043	37,456	2,413	4.2.7
501300	Long-Term Disability	3,936,983	4,208,064	271,081	4.2.7
5016XX	Worker's Compensation	1,156,797	1,236,449	79,651	4.2.7
502900	Other Salary Overhead	611,077	611,077	-	4.2.7
	<b>Total Benefits</b>	<b>107,764,220</b>	<b>116,300,054</b>	<b>8,535,834</b>	4.2.7
	<b>Subtotal Pensions and Benefits</b>	<b>121,249,048</b>	<b>127,631,431</b>	<b>6,382,383</b>	4.2.7
580XXX	Payroll Tax Expense	38,502,103	40,709,542	2,207,439	4.2.8
580700	Payroll Tax Expense-Unemployment	3,138,484	3,138,484	-	
	<b>Total Payroll Taxes</b>	<b>41,640,586</b>	<b>43,848,026</b>	<b>2,207,439</b>	
	<b>Total Labor</b>	<b>725,259,215</b>	<b>765,023,015</b>	<b>39,763,799</b>	4.2.11
	Non-Utility and Capitalized Labor	255,390,134	269,392,413	14,002,279	4.2.11
	<b>Total Utility Labor</b>	<b>469,869,081</b>	<b>495,630,601</b>	<b>25,761,520</b>	4.2.11

Ref. 4.2

PacifiCorp  
Oregon General Rate Case - December 2023  
Escalation of Regular, Overtime, and Premium Labor  
(Figures are in thousands)

Base Period: 12 Months Ended June 2021  
Pro Forma: 12 Months Ending December 2023

Labor (12 Months Ended June 2021)

Acct	Account Desc.	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
5001XX	Reg/Ordinary Time	38,876	35,124	36,232	36,915	35,229	38,617	34,599	33,011	39,286	36,563	34,667	36,155	435,273
5002XX	Overtime	6,242	6,429	15,102	5,147	4,945	5,939	5,000	7,912	4,792	7,095	4,582	5,690	78,874
5003XX	Premium Pay	1,197	1,093	1,763	936	981	919	746	784	892	1,062	909	1,210	12,492
<b>Grand Total</b>		<b>46,314</b>	<b>42,646</b>	<b>53,096</b>	<b>42,998</b>	<b>41,154</b>	<b>45,474</b>	<b>40,345</b>	<b>41,707</b>	<b>44,971</b>	<b>44,720</b>	<b>40,158</b>	<b>43,054</b>	<b>526,639</b>

Ref. 4.2.2  
Ref. 4.2.2  
Ref. 4.2.2  
Ref. 4.2.2

Labor (12 Months Ended June 2021)

Group Code	Labor Group	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
2	Officer/Exempt	17,919	15,412	16,226	17,279	15,197	17,435	15,739	14,376	18,183	16,801	14,865	15,518	194,950
3	IBEW 125	3,485	3,436	4,193	3,315	3,137	3,329	3,216	4,122	3,460	3,463	3,437	3,542	42,135
4	IBEW 659	4,066	3,980	9,088	3,713	3,786	3,848	3,704	5,244	3,713	3,535	3,439	3,808	51,923
5	UWUA 197	180	225	249	196	240	188	247	263	191	174	156	170	2,480
8	UWUA 127	4,303	4,458	4,780	4,209	4,116	4,730	3,919	3,581	4,098	5,040	3,751	4,136	51,122
9	IBEW 57 WY	64	91	100	69	70	57	61	48	58	57	67	60	800
11	IBEW 57 PD	10,258	9,589	12,748	8,667	9,155	9,730	8,186	8,960	9,559	9,670	9,128	10,361	116,011
12	IBEW 57 PS	3,776	3,416	3,542	3,495	3,461	3,878	3,229	3,152	3,443	3,853	3,350	3,421	42,015
13	PCCC Non-Exempt	495	474	531	477	491	572	518	507	530	504	481	473	6,054
15	IBEW 57 CT	352	334	352	324	336	365	323	326	390	372	322	348	4,144
16	IBEW 77	135	131	137	128	129	152	138	130	126	122	126	136	1,590
18	Non-Exempt	1,281	1,101	1,151	1,126	1,036	1,190	1,065	997	1,219	1,130	1,036	1,083	13,414
<b>Grand Total</b>		<b>46,314</b>	<b>42,646</b>	<b>53,096</b>	<b>42,998</b>	<b>41,154</b>	<b>45,474</b>	<b>40,345</b>	<b>41,707</b>	<b>44,971</b>	<b>44,720</b>	<b>40,158</b>	<b>43,054</b>	<b>526,639</b>

Annualization Increase

Group Code	Labor Group	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
2	Officer/Exempt							1.49%					
3	IBEW 125								2.50%				
4	IBEW 659										2.50%		
5	UWUA 197											2.50%	
8	UWUA 127				2.00%								
9	IBEW 57 WY	3.10%											
11	IBEW 57 PD								2.50%				
12	IBEW 57 PS								2.50%				
13	PCCC Non-Exempt							1.16%					
15	IBEW 57 CT								2.50%				
16	IBEW 77								0.00%				
18	Non-Exempt							1.48%					

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Note: Please see Confidential Exhibit PAC/1004 for redacted information.

Annualized Labor June 2021

Group Code	Labor Group	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
2	Officer/Exempt	18,186	15,641	16,468	17,537	15,424	17,695	15,739	14,376	18,183	16,801	14,865	15,518	196,432
3	IBEW 125	3,572	3,521	4,297	3,398	3,215	3,413	3,296	4,122	3,460	3,463	3,437	3,542	42,738
4	IBEW 659	4,168	4,079	9,315	3,806	3,880	3,944	3,797	5,375	3,806	3,623	3,439	3,808	53,040
5	UWUA 197	184	231	255	201	246	193	254	270	196	178	160	170	2,538
8	UWUA 127	4,389	4,547	4,876	4,209	4,116	4,730	3,919	3,581	4,098	5,040	3,751	4,136	51,393
9	IBEW 57 WY	64	91	100	69	70	57	61	48	58	57	67	60	800
11	IBEW 57 PD	10,515	9,829	13,067	8,884	9,384	9,973	8,390	8,960	9,559	9,670	9,128	10,361	117,719
12	IBEW 57 PS	3,871	3,502	3,630	3,582	3,547	3,975	3,309	3,152	3,443	3,853	3,350	3,421	42,635
13	PCCC Non-Exempt	501	479	537	482	497	579	518	507	530	504	481	473	6,089
15	IBEW 57 CT	361	342	361	332	344	374	331	326	390	372	322	348	4,203
16	IBEW 77	135	131	137	128	129	152	138	130	126	122	126	136	1,590
18	Non-Exempt	1,300	1,117	1,168	1,142	1,052	1,207	1,065	997	1,219	1,130	1,036	1,083	13,516
<b>Grand Total</b>		<b>47,245</b>	<b>43,511</b>	<b>54,211</b>	<b>43,771</b>	<b>41,904</b>	<b>46,292</b>	<b>40,818</b>	<b>41,845</b>	<b>45,069</b>	<b>44,813</b>	<b>40,162</b>	<b>43,054</b>	<b>532,694</b>

Ref. 4.2.2

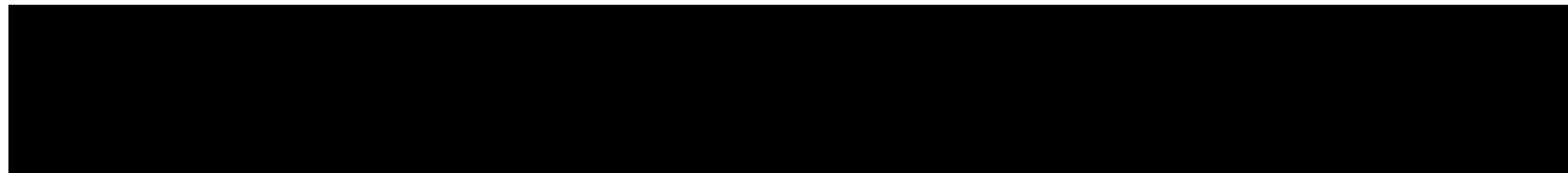
Pro Forma Increase to December 2023

Increases occur on the 26th of each month. For this exhibit, each increase is listed on the first day of the following month.

Group Code	Labor Group	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2	Officer/Exempt												
3	IBEW 125												
4	IBEW 659												
5	UWUA 197												
8	UWUA 127												
9	IBEW 57 WY												

Note: Please see Confidential Exhibit PAC/1004 for redacted information.

11	IBEW 57 PD	
12	IBEW 57 PS	
13	PCCC Non-Exempt	
15	IBEW 57 CT	
16	IBEW 77	
18	Non-Exempt	



Pro Forma Labor December 2023

Group Code	Labor Group	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Total
2	Officer/Exempt													
3	IBEW 125													
4	IBEW 659													
5	UWUA 197													
8	UWUA 127													
9	IBEW 57 WY													
11	IBEW 57 PD													
12	IBEW 57 PS													
13	PCCC Non-Exempt													
15	IBEW 57 CT													
16	IBEW 77													
18	Non-Exempt													
<b>Grand Total</b>														<b>562,900</b>

Ref. 4.2.2

**PacifiCorp  
Oregon General Rate Case - December 2023  
Wage and Employee Benefit Adjustment**

*Note: Please see Confidential Exhibit PAC/1004 for redacted information.*

**Composite Labor Increases**

Regular Time/Overtime/Premium Pay Annualize - Actual	526,638,732		<b>Ref.</b>
Regular Time/Overtime/Premium Pay December 2023 - Pro Forma	562,900,461	<sup>1</sup> CAGR	4.2.2
% Increase	6.89%	2.70%	4.2.2

**Miscellaneous Bare Labor Escalation**

<b>Description</b>	<b>Account</b>	<b>June 2021 Actual</b>	<b>Pro Forma Increase</b>	<b>December 2023 Pro Forma</b>	<b>Pro Forma Adjustment</b>	<b>Ref.</b>
Unused Sick Leave Accrual	5005XX	3,238,340	6.89%	3,461,316	<b>222,976</b>	4.2.2
Severance	500700	2,823,587	n/a	324,311	<b>(2,499,276)</b>	4.2.2 <sup>3</sup>
Joint Owner Cutbacks	50109X	(1,116,081)	6.89%	(1,192,928)	<b>(76,848)</b>	4.2.2
		<u>4,945,847</u>		<u>2,592,699</u>	<u>(2,353,148)</u>	

**Annual Incentive Plan Escalation**

<b>Description</b>	<b>Account</b>	<b>June 2021 Actual</b>	<b>December 2023 Pro Forma</b>	<b><sup>2</sup> Remove (NEO's) and One-half of Remaining AIP</b>	<b>Pro Forma Adjustment</b>	<b>Ref.</b>
Annual Incentive Plan Compensation	500410	19,621,442		16,886,838	(2,734,605)	4.2.2

<sup>1</sup>Compound Annual Growth Rate

<sup>2</sup>Per Commission Order in GRC UE-374, Order No. 20-473

<sup>3</sup>Removes severance entries associated with the Cholla Unit 4 Closure

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Wage and Employee Benefit Adjustment**

Account	Description	A	B	C	D	D - A	Ref
		Actual June 2021 Net of Joint Venture	Actual June 2021 Gross	Projected December 2023 Gross	Projected December 2023 Net of Joint Venture	Pro Forma Adjustment	
50110X	Pensions	6,136,263	6,240,523	4,900,000	4,818,137	(1,318,127)	4.2.2
501115	SERP Plan	0	0	-	-	(0)	4.2.2
50115X	Post Retirement Benefits	947,520	985,704	1,895,032	1,821,623	874,103	4.2.2
501160	Post Employment Benefits	6,401,045	6,607,102	4,842,646	4,691,617	(1,709,428)	4.2.2
	Subtotal	13,484,828	13,833,328	11,637,678	11,331,377	(2,153,451)	4.2.2
501102	Pension Administration	2,012,320	2,077,285	926,038	897,077	(1,115,243)	4.2.2
50112X	Medical	55,789,610	57,591,269	63,240,000	61,261,629	5,472,019	4.2.2
50117X	Dental	3,569,680	3,687,796	4,490,000	4,346,190	776,510	4.2.2
50120X	Vision	257,722	264,719	540,000	525,727	268,005	4.2.2
50122X	Life	818,089	846,031	904,285	874,419	56,330	4.2.2
50125X	401(k)	39,576,899	40,857,477	43,670,720	42,301,967	2,725,069	4.2.2
501251	401(k) Administration	(0)	6	-	-	0	4.2.2
501275	Accidental Death & Disability	35,043	35,347	37,780	37,456	2,413	4.2.2
501300	Long-Term Disability	3,936,983	4,063,380	4,343,164	4,208,064	271,081	4.2.2
5016XX	Worker's Compensation	1,156,797	1,192,106	1,274,189	1,236,449	79,651	4.2.2
502900	Other Salary Overhead	611,077	612,112	612,112	611,077	-	4.2.2
	Subtotal	107,764,220	111,227,527	120,038,287	116,300,054	8,535,834	4.2.2
	Grand Total	<b>121,249,048</b>	125,060,855	131,675,965	<b>127,631,431</b>	<b>6,382,383</b>	4.2.2
		<b>Ref. 4.2.2</b>			<b>Ref. 4.2.2</b>	<b>Ref. 4.2.2</b>	

**PacifiCorp  
Oregon General Rate Case - December 2023  
Wage and Employee Benefit Adjustment**

	<u>Line No.</u>	<u>Ref</u>	<u>Social Security</u>	<u>Medicare</u>	<u>Total FICA Tax</u>	<u>Ref</u>
<b>FICA Calculated on December 2023 Pro Forma Labor</b>						
Pro Forma Wages Adjustment	a		33,685,605	33,685,605		4.2.2
Pro Forma Incentive Adjustment	b		(2,734,605)	(2,734,605)		4.2.2
	c	a + b	30,951,001	30,951,001		
Percentage of eligible wages	d		91.65%	100.00%		
Total eligible wages	e	c * d	28,365,320	30,951,001		
Tax rate	f		6.20%	1.45%		
Tax on eligible wages	g	e * f	1,758,650	448,790		
<b>Total FICA Tax on Pro Forma Labor</b>		g	<b>1,758,650</b>	<b>448,790</b>	<b>2,207,439</b>	<b>4.2.2</b>

PacifiCorp  
Oregon General Rate Case - December 2023  
Wage and Employee Benefit Adjustment

2020P Indicator	Actual		Pro Forma Adjustment	Pro Forma		Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2023 Oregon Allocated
	12 Months Ended June 2021	% Of Total		12 Months Ending December 2023				
500SG	13,632,623	1.880%	747,436	14,380,060	26.070%	194,859	3,748,931	
502SG	19,155,571	2.641%	1,050,243	20,205,814	26.070%	273,802	5,267,725	
503SE	89,493	0.012%	4,907	94,399	25.068%	1,230	23,664	
505SG	66,888	0.009%	3,667	70,555	26.070%	956	18,394	
506SG	30,372,547	4.188%	1,665,236	32,037,783	26.070%	434,133	8,352,360	
510SG	4,534,192	0.625%	248,596	4,782,788	26.070%	64,810	1,246,889	
511SG	8,134,447	1.122%	445,987	8,580,435	26.070%	116,270	2,236,949	
512SG	23,354,332	3.220%	1,280,448	24,634,781	26.070%	333,817	6,422,372	
513SG	10,913,109	1.505%	598,333	11,511,442	26.070%	155,988	3,001,072	
514SG	2,241,529	0.309%	122,896	2,364,425	26.070%	32,039	616,414	
535SG-P	5,273,065	0.727%	289,106	5,562,171	26.070%	75,371	1,450,077	
535SG-U	3,351,104	0.462%	183,731	3,534,835	26.070%	47,899	921,544	
536SG-P	65,898	0.009%	3,613	69,511	26.070%	942	18,122	
537SG-P	510,636	0.070%	27,997	538,633	26.070%	7,299	140,423	
537SG-U	28,114	0.004%	1,541	29,655	26.070%	402	7,731	
539SG-P	6,399,565	0.882%	350,869	6,750,434	26.070%	91,473	1,759,861	
539SG-U	4,965,120	0.685%	272,223	5,237,343	26.070%	70,969	1,365,393	
542SG-P	327,201	0.045%	17,939	345,141	26.070%	4,677	89,979	
542SG-U	46,799	0.006%	2,566	49,364	26.070%	669	12,869	
543SG-P	318,638	0.044%	17,470	336,108	26.070%	4,554	87,624	
543SG-U	144,486	0.020%	7,922	152,407	26.070%	2,065	39,733	
544SG-P	944,095	0.130%	51,762	995,857	26.070%	13,495	259,623	
544SG-U	173,217	0.024%	9,497	182,714	26.070%	2,476	47,634	
545SG-P	960,823	0.132%	52,679	1,013,502	26.070%	13,734	264,223	
545SG-U	197,353	0.027%	10,820	208,173	26.070%	2,821	54,272	
546SG	5,787	0.001%	317	6,104	26.070%	83	1,591	
548SG	5,657,523	0.780%	310,185	5,967,708	26.070%	80,866	1,555,802	
549OR	19,124	0.003%	1,048.52	20,173	Situs	1,048.52	20,173	
549SG	4,376,273	0.603%	239,938	4,616,211	26.070%	62,553	1,203,462	
552SG	1,064,019	0.147%	58,337	1,122,356	26.070%	15,209	292,602	
553SG	2,089,352	0.288%	114,553	2,203,905	26.070%	29,864	574,566	
554SG	85,332	0.012%	4,679	90,011	26.070%	1,220	23,466	
556SG	263,837	0.036%	14,465	278,302	26.070%	3,771	72,554	
557ID	69,384	0.010%	3,804	73,188	Situs	-	-	
557SG	29,009,710	4.000%	1,590,516	30,600,226	26.070%	414,653	7,977,583	
560SG	8,483,712	1.170%	465,137	8,948,848	26.070%	121,263	2,332,995	
561SG	10,621,907	1.465%	582,367	11,204,275	26.070%	151,825	2,920,993	
562SG	1,730,531	0.239%	94,880	1,825,411	26.070%	24,735	475,891	
563SG	505,793	0.070%	27,731	533,525	26.070%	7,230	139,092	
566SG	74,754	0.010%	4,099	78,852	26.070%	1,068	20,557	
567SG	101,169	0.014%	5,547	106,716	26.070%	1,446	27,821	
568SG	883,480	0.122%	48,439	931,919	26.070%	12,628	242,954	
569SG	2,754,076	0.380%	150,998	2,905,074	26.070%	39,366	757,363	
570SG	6,311,786	0.870%	346,056	6,657,843	26.070%	90,218	1,735,722	
571SG	3,581,589	0.494%	196,368	3,777,956	26.070%	51,194	984,926	
572SG	51,161	0.007%	2,805	53,966	26.070%	731	14,069	
580CA	(1,637)	0.000%	(90)	(1,727)	Situs	-	-	
580ID	45,109	0.006%	2,473	47,582	Situs	-	-	
580OR	319,311	0.044%	17,506.85	336,818	Situs	17,506.85	336,818	
580SNPD	7,549,492	1.041%	413,916	7,963,408	26.473%	109,574	2,108,121	
580UT	57,344	0.008%	3,144	60,488	Situs	-	-	
580WA	335,385	0.046%	18,388	353,773	Situs	-	-	
580WYP	86,611	0.012%	4,749	91,360	Situs	-	-	
581SNPD	12,876,362	1.775%	705,973	13,582,335	26.473%	186,889	3,595,597	
582CA	32,613	0.004%	1,788	34,401	Situs	-	-	
582ID	110,031	0.015%	6,033	116,063	Situs	-	-	
582OR	316,930	0.044%	17,376.34	334,307	Situs	17,376.34	334,307	
582SNPD	979	0.000%	54	1,032	26.473%	14	273	
582UT	757,951	0.105%	41,556	799,508	Situs	-	-	
582WA	99,612	0.014%	5,461	105,073	Situs	-	-	
582WYP	390,342	0.054%	21,401	411,743	Situs	-	-	
583CA	636,751	0.088%	34,911	671,662	Situs	-	-	
583ID	217,551	0.030%	11,928	229,479	Situs	-	-	
583OR	1,323,385	0.182%	72,557.26	1,395,942	Situs	72,557.26	1,395,942	
583SNPD	163	0.000%	9	172	26.473%	2	45	
583UT	4,466,428	0.616%	244,881	4,711,309	Situs	-	-	
583WA	256,645	0.035%	14,071	270,716	Situs	-	-	
583WYP	255,410	0.035%	14,003	269,414	Situs	-	-	
583WYU	58,617	0.008%	3,214	61,830	Situs	-	-	

Oregon General Rate Case - December 2023  
Wage and Employee Benefit Adjustment

2020P Indicator	Actual		Pro Forma Adjustment	Pro Forma 12 Months Ending December 2023	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2023 Oregon Allocated
	12 Months Ended June 2021	% Of Total					
585SNPD	249,361	0.034%	13,672	263,033	26.473%	3,619	69,632
586CA	82,097	0.011%	4,501	86,598	Situs	-	-
586ID	139,542	0.019%	7,651	147,193	Situs	-	-
586OR	1,027,193	0.142%	56,317.95	1,083,511	Situs	56,317.95	1,083,511
586UT	405,264	0.056%	22,219	427,483	Situs	-	-
586WA	297,130	0.041%	16,291	313,421	Situs	-	-
586WYP	201,095	0.028%	11,025	212,121	Situs	-	-
586WYU	66,447	0.009%	3,643	70,091	Situs	-	-
587CA	438,562	0.060%	24,045	462,607	Situs	-	-
587ID	681,114	0.094%	37,343	718,457	Situs	-	-
587OR	5,038,483	0.695%	276,244.97	5,314,728	Situs	276,244.97	5,314,728
587UT	4,431,429	0.611%	242,962	4,674,391	Situs	-	-
587WA	1,065,097	0.147%	58,396	1,123,493	Situs	-	-
587WYP	963,538	0.133%	52,828	1,016,366	Situs	-	-
587WYU	92,288	0.013%	5,060	97,348	Situs	-	-
588CA	(17,937)	-0.002%	(983)	(18,921)	Situs	-	-
588ID	(8,402)	-0.001%	(461)	(8,862)	Situs	-	-
588OR	(69,351)	-0.010%	(3,802.33)	(73,154)	Situs	(3,802.33)	(73,154)
588SNPD	2,544,950	0.351%	139,532	2,684,482	26.473%	36,938	710,652
588UT	247,754	0.034%	13,584	261,337	Situs	-	-
588WA	7,200	0.001%	395	7,595	Situs	-	-
588WYP	(365)	0.000%	(20)	(385)	Situs	-	-
588WYU	(53,280)	-0.007%	(2,921)	(56,201)	Situs	-	-
589CA	20,049	0.003%	1,099	21,148	Situs	-	-
589ID	14,424	0.002%	791	15,215	Situs	-	-
589OR	114,722	0.016%	6,289.86	121,012	Situs	6,289.86	121,012
589UT	335,267	0.046%	18,382	353,649	Situs	-	-
589WA	10,734	0.001%	589	11,322	Situs	-	-
589WYP	88,779	0.012%	4,868	93,647	Situs	-	-
589WYU	11,861	0.002%	650	12,511	Situs	-	-
590CA	102,277	0.014%	5,608	107,885	Situs	-	-
590ID	218,231	0.030%	11,965	230,196	Situs	-	-
590OR	700,167	0.097%	38,388.07	738,555	Situs	38,388.07	738,555
590SNPD	2,586,908	0.357%	141,832	2,728,740	26.473%	37,547	722,368
590UT	913,615	0.126%	50,091	963,706	Situs	-	-
590WA	166,440	0.023%	9,125	175,565	Situs	-	-
590WYP	349,882	0.048%	19,183	369,065	Situs	-	-
591SNPD	421	0.000%	23	445	26.473%	6	118
592CA	516,199	0.071%	28,302	544,501	Situs	-	-
592ID	273,616	0.038%	15,002	288,617	Situs	-	-
592OR	2,002,428	0.276%	109,787.17	2,112,216	Situs	109,787.17	2,112,216
592SNPD	1,335,668	0.184%	73,231	1,408,899	26.473%	19,386	372,972
592UT	1,461,818	0.202%	80,147	1,541,965	Situs	-	-
592WA	413,294	0.057%	22,660	435,954	Situs	-	-
592WYP	583,579	0.080%	31,996	615,575	Situs	-	-
593CA	4,642,317	0.640%	254,524	4,896,841	Situs	-	-
593ID	4,566,290	0.630%	250,356	4,816,646	Situs	-	-
593OR	28,068,609	3.870%	1,538,918.13	29,607,528	Situs	1,538,918.13	29,607,528
593SNPD	1,847,350	0.255%	101,285	1,948,635	26.473%	26,813	515,854
593UT	27,802,996	3.834%	1,524,355	29,327,352	Situs	-	-
593WA	4,351,067	0.600%	238,556	4,589,623	Situs	-	-
593WYP	6,864,745	0.947%	376,373	7,241,119	Situs	-	-
593WYU	612,106	0.084%	33,560	645,665	Situs	-	-
594CA	318,476	0.044%	17,461	335,937	Situs	-	-
594ID	412,481	0.057%	22,615	435,096	Situs	-	-
594OR	3,901,319	0.538%	213,897.67	4,115,216	Situs	213,897.67	4,115,216
594SNPD	18,455	0.003%	1,012	19,467	26.473%	268	5,153
594UT	6,585,836	0.908%	361,082	6,946,918	Situs	-	-
594WA	864,643	0.119%	47,406	912,049	Situs	-	-
594WYP	597,900	0.082%	32,781	630,682	Situs	-	-
594WYU	91,719	0.013%	5,029	96,747	Situs	-	-
595SNPD	959,144	0.132%	52,587	1,011,731	26.473%	13,921	267,832
596CA	37,045	0.005%	2,031	39,077	Situs	-	-
596ID	44,578	0.006%	2,444	47,022	Situs	-	-
596OR	442,012	0.061%	24,234.21	466,246	Situs	24,234.21	466,246
596UT	162,385	0.022%	8,903	171,288	Situs	-	-
596WA	27,712	0.004%	1,519	29,232	Situs	-	-
596WYP	247,587	0.034%	13,574	261,162	Situs	-	-
596WYU	31,037	0.004%	1,702	32,739	Situs	-	-

Oregon General Rate Case - December 2023  
Wage and Employee Benefit Adjustment

2020P Indicator	Actual		Pro Forma Adjustment	Pro Forma 12 Months Ending December 2023	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2023 Oregon Allocated
	12 Months Ended June 2021	% Of Total					
597CA	12,800	0.002%	702	13,502	Situs	-	-
597ID	27,373	0.004%	1,501	28,874	Situs	-	-
597OR	173,588	0.024%	9,517.29	183,105	Situs	9,517.29	183,105
597SNPD	(70,295)	-0.010%	(3,854)	(74,149)	26.473%	(1,020)	(19,629)
597UT	262,165	0.036%	14,374	276,539	Situs	-	-
597WA	21,109	0.003%	1,157	22,267	Situs	-	-
597WYP	17,829	0.002%	978	18,807	Situs	-	-
597WYU	18,826	0.003%	1,032	19,859	Situs	-	-
598CA	5,497	0.001%	301	5,799	Situs	-	-
598OR	23,466	0.003%	1,286.60	24,753	Situs	1,286.60	24,753
598SNPD	(1,572,321)	-0.217%	(86,206)	(1,658,526)	26.473%	(22,821)	(439,055)
598WA	27,182	0.004%	1,490	28,673	Situs	-	-
901CN	1,689,675	0.233%	92,640	1,782,315	30.990%	28,709	552,338
902CA	314,956	0.043%	17,268	332,224	Situs	-	-
902CN	303,805	0.042%	16,657	320,461	30.990%	5,162	99,311
902ID	1,610,394	0.222%	88,293	1,698,687	Situs	-	-
902OR	1,407,414	0.194%	77,164.32	1,484,578	Situs	77,164.32	1,484,578
902UT	4,421,298	0.610%	242,407	4,663,705	Situs	-	-
902WA	888,713	0.123%	48,725	937,439	Situs	-	-
902WYP	772,799	0.107%	42,370	815,169	Situs	-	-
902WYU	144,870	0.020%	7,943	152,813	Situs	-	-
903CA	17,721	0.002%	972	18,693	Situs	-	-
903CN	25,159,388	3.469%	1,379,414	26,538,802	30.990%	427,479	8,224,356
903ID	220,123	0.030%	12,069	232,192	Situs	-	-
903OR	303,686	0.042%	16,650.21	320,336	Situs	16,650.21	320,336
903UT	1,076,476	0.148%	59,020	1,135,496	Situs	-	-
903WA	85,485	0.012%	4,687	90,172	Situs	-	-
903WYP	264,505	0.036%	14,502	279,007	Situs	-	-
903WYU	51,717	0.007%	2,836	54,553	Situs	-	-
907CN	2,858	0.000%	157	3,015	30.990%	49	934
908CA	27	0.000%	1	29	Situs	-	-
908CN	1,913,425	0.264%	104,907	2,018,332	30.990%	32,511	625,480
908ID	14,124	0.002%	774	14,898	Situs	-	-
908OR	2,133,756	0.294%	116,987.47	2,250,743	Situs	116,987.47	2,250,743
908OTHER	33,413	0.005%	1,832	35,245	0.000%	-	-
908UT	2,846,724	0.393%	156,077	3,002,802	Situs	-	-
908WA	319,510	0.044%	17,518	337,028	Situs	-	-
908WYP	957,109	0.132%	52,475	1,009,585	Situs	-	-
909CN	1,693,067	0.233%	92,826	1,785,893	30.990%	28,767	553,447
920OR	907,381	0.125%	49,748.97	957,130	Situs	49,748.97	957,130
920SO	75,668,430	10.433%	4,148,674	79,817,104	27.173%	1,127,323	21,688,767
920UT	1,534,150	0.212%	84,113	1,618,263	Situs	-	-
920WYP	509,969	0.070%	27,960	537,929	Situs	-	-
921SO	3,300,981	0.455%	180,983	3,481,963	27.173%	49,179	946,157
922SO	(27,772,793)	-3.829%	(1,522,699)	(29,295,492)	27.173%	(413,764)	(7,960,488)
928CA	3,589	0.000%	197	3,785	Situs	-	-
928ID	139,776	0.019%	7,664	147,440	Situs	-	-
928OR	304,110	0.042%	16,673.46	320,784	Situs	16,673.46	320,784
928SO	383,123	0.053%	21,006	404,129	27.173%	5,708	109,814
928UT	368,546	0.051%	20,206	388,752	Situs	-	-
928WA	88,677	0.012%	4,862	93,538	Situs	-	-
928WYP	461,408	0.064%	25,298	486,705	Situs	-	-
929SO	(3,391,347)	-0.468%	(185,937)	(3,577,284)	27.173%	(50,525)	(972,058)
935CA	5,461	0.001%	299	5,760	Situs	-	-
935OR	10,008	0.001%	548.72	10,557	Situs	548.72	10,557
935SO	2,070,162	0.285%	113,501	2,183,662	27.173%	30,842	593,368
935WA	3,264	0.000%	179	3,443	Situs	-	-
<b>Utility Labor</b>	<b>469,869,081</b>	<b>64.786%</b>	<b>25,761,520</b>	<b>495,630,601</b>		<b>7,396,589</b>	<b>142,304,332</b>
						<b>Ref 4.2</b>	
Capital/Non Utility	255,390,134	35.214%	14,002,279	269,392,413			
<b>Total Labor</b>	<b>725,259,215</b>	<b>100.00%</b>	<b>39,763,799</b>	<b>765,023,015</b>			
	<b>Ref 4.2.2</b>	<b>Ref 4.2.2</b>	<b>Ref 4.2.2</b>	<b>Ref 4.2.2</b>			



**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Pension Related Non-Service Expense**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Pension Non-Service Expense	926	3	2,871,029	SO	27.173%	780,147	4.3.1
Post-Retirement Non-Service Exp.	926	3	867,276	SO	27.173%	235,666	4.3.1
SERP Non-Service Expense	926	3	<u>(2,768,076)</u>	SO	27.173%	<u>(752,171)</u>	4.3.1
			970,230			263,641	
Pension Settle. Loss Amortization Exp.	926	3	1,271,364	SO	27.173%	345,469	4.3.3

**Description of Adjustment:**

This adjustment includes the pension and post-retirement non-service expenses at the 2023 forecast level.

These expenses have historically been included in the company's Results of Operations report in the Wage and Employee Benefit Adjustments (WEBA) adjustment no.'s 4.2. Since these expenses are not included in the Company's capitalization calculations they will be accounted for in this new adjustment going forward. All other pension related service expenses will continue to be included in the WEBA adjustment.

This adjustment also adds pension settlement loss amortization expense on losses either incurred or forecasted from the start of the base period through December 2022, with each loss amortized over a 20 year period from occurrence. This approach is consistent with the Company's proposed accounting treatment in deferral application Docket No. UM 2185.

PacifiCorp  
Oregon General Rate Case - December 2023  
Pension Related Non-Service Expense

Description	GL 554012	GL 554022	GL 554032	Total Actual	FERC Acct	Factor
	Post-Retirement					
	Pension Non-Service Expense	Non-Service Expense	SERP Non-Service Expense			
	Actual Twelve Months Ended June 2021	Actual Twelve Months Ended June 2021	Actual Twelve Months Ended June 2021			
Jul-2020	(399,614)	(369,812)	231,616	(537,811)	926	SO
Aug-2020	(399,614)	(364,341)	231,616	(532,339)	926	SO
Sep-2020	(399,614)	(364,341)	231,616	(532,339)	926	SO
Oct-2020	(399,614)	(364,341)	231,616	(532,339)	926	SO
Nov-2020	(399,614)	(364,341)	231,616	(532,339)	926	SO
Dec-2020	(399,614)	(364,341)	231,616	(532,339)	926	SO
Jan-2021	(701,505)	(107,969)	229,730	(579,744)	926	SO
Feb-2021	(701,505)	(107,969)	229,730	(579,744)	926	SO
Mar-2021	(701,505)	(107,969)	229,730	(579,744)	926	SO
Apr-2021	(701,505)	(107,969)	229,730	(579,744)	926	SO
May-2021	(701,505)	(107,969)	229,730	(579,744)	926	SO
Jun-2021	(701,505)	(142,103)	229,730	(613,878)	926	SO
Total Actual	<b>(6,606,714)</b>	<b>(2,873,466)</b>	<b>2,768,076</b>	<b>(6,712,105)</b>		

Description	GL 554012	GL 554022	GL 554032	Total Forecast	FERC Acct	Factor
	Post-Retirement					
	Pension Non-Service Expense	Non-Service Expense	SERP Non-Service Expense			
	Actual Twelve Months Ending December 2023	Actual Twelve Months Ending December 2023	Actual Twelve Months Ending December 2023			
Jan-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Feb-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Mar-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Apr-2023	(311,307)	(167,183)	-	(478,490)	926	SO
May-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Jun-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Jul-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Aug-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Sep-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Oct-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Nov-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Dec-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Total Forecasted	<b>(3,735,685)</b>	<b>(2,006,190)</b>	<b>-</b>	<b>(5,741,875)</b>		
Total Incremental Change	<b>2,871,029</b>	<b>867,276</b>	<b>(2,768,076)</b>	<b>970,230</b>		
	<b>Ref 4.3</b>	<b>Ref 4.3</b>	<b>Ref 4.3</b>	<b>Ref 4.3</b>		

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Pension Related Non-Service Expense**  
**Settlement Loss Amortization Expense**

<b>Description</b>	<b>Actual 12 Months Ended June 2021</b>	<b>Current Period Amortization (over 20 Years)</b>	<b>FERC Acct</b>	<b>Factor</b>
Pension Settlement Losses:				
Jul-20	-	-	926	SO
Aug-20	-	-	926	SO
Sep-20	-	-	926	SO
Oct-20	-	-	926	SO
Nov-20	-	-	926	SO
Dec-20	-	-	926	SO
Jan-21	-	-	926	SO
Feb-21	-	-	926	SO
Mar-21	-	-	926	SO
Apr-21	-	-	926	SO
May-21	-	-	926	SO
Jun-21	-	-	926	SO
Total Incurred	-	-		

<b>Description</b>	<b>July 2021 to Dec 2022</b>	<b>Current Period Amortization (over 20 Years):</b>	<b>FERC Acct</b>	<b>Factor</b>
Pension Settlement Losses:				
Jul-21	-	-	926	SO
Aug-21	8,947,043	-	926	SO
Sep-21	-	37,279	926	SO
Oct-21	-	37,279	926	SO
Nov-21	-	37,279	926	SO
Dec-21	6,699,344	37,279	926	SO
Jan-22	-	65,193	926	SO
Feb-22	-	65,193	926	SO
Mar-22	-	65,193	926	SO
Apr-22	-	65,193	926	SO
May-22	-	65,193	926	SO
Jun-22	-	65,193	926	SO
Jul-22	-	65,193	926	SO
Aug-22	-	65,193	926	SO
Sep-22	-	65,193	926	SO
Oct-22	-	65,193	926	SO
Nov-22	-	65,193	926	SO
Dec-22	9,780,891	65,193	926	SO
	25,427,278	931,437		

**PacifiCorp  
Oregon General Rate Case - December 2023  
Pension Related Non-Service Expense  
Settlement Loss Amortization Expense**

<b>Description</b>	<b>Forecasted 12 Months Ended December 2023</b>	<b>Current Period Amortization (over 20 Years):</b>	<b>FERC Acct</b>	<b>Factor</b>
Pension Settlement Losses:				
Jan-23	-	105,947	926	SO
Feb-23	-	105,947	926	SO
Mar-23	-	105,947	926	SO
Apr-23	-	105,947	926	SO
May-23	-	105,947	926	SO
Jun-23	-	105,947	926	SO
Jul-23	-	105,947	926	SO
Aug-23	-	105,947	926	SO
Sep-23	-	105,947	926	SO
Oct-23	-	105,947	926	SO
Nov-23	-	105,947	926	SO
Dec-23	-	105,947	926	SO
Total Incurred	-	<b>1,271,364</b>		
		<b>Ref 4.3</b>		

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Remove Non-Recurring Entries**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Remove non-recurring settlement exp.	545	1	(33,000,000)	SG	26.070%	(8,603,213)	4.4.1

This adjustment removes the accrual of environmental costs related to the Klamath Settlement. Environmental remediation spending, once incurred and actual amounts known, are recorded to a regulatory asset and amortized straight-line over a 10-year period since approval in Docket No. UE-147. Expense resulting from amortization of environmental costs spent are included in FERC account 925 for recovery in rates.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Remove Non-Recurring Entries**

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<b>FERC Account</b>	<b>Account Number</b>	<b>Description</b>	<b>Amount</b>	<b>Alloc</b>	<b>REF</b>
5459000	545500	Reversal of Klamath Settlement Obligation Expense Accrual	33,000,000	SG	Ref. 4.4

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Insurance Expense**

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	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Remove Base Pd. Inj & Damage	925	1	(139,344,910)	SO	27.173%	(37,864,307)	4.5.1
Remove Base Pd. Inj & Damage	925	1	(1,484,743)	OR	Situs	(1,484,743)	4.5.1
Adj. Inj & Damage to 3-yr avg.	925	3	1,608,709	OR	Situs	1,608,709	4.5.2
<u>Adjust property damage expense to 10-year average</u>							
Property Insurance - Transmission	924	3	34,764	OR	Situs	34,764	4.5.3
Property Insurance - OR Dist.	924	3	2,355,785	OR	Situs	2,355,785	4.5.3
Property Insurance - Non-T&D	924	3	(85,052)	OR	Situs	(85,052)	4.5.3
<u>Property Reserve Balance Amortization</u>							
June 2021 Balance Amortization	924	3	2,093,761	OR	Situs	2,093,761	4.5.4
Adjust Liability Insurance Premium	925	3	20,792,083	SO	27.173%	5,649,850	4.5.5
Adjust Property Insurance Premium	924	3	(758,963)	SO	27.173%	(206,234)	4.5.5
<b>Adjustment to Rate Base:</b>							
Remove Injuries & Damages Reserve	2282	3	141,155,665	SO	27.173%	38,356,344	4.5.1
<b>Adjustment to Tax:</b>							
Schedule M - OR Prop Res Amort	SCHMAT	3	10,061,436	OR	Situs	10,061,436	
Def Inc Tax Exp-OR Prop Amort	41110	3	(2,473,765)	OR	Situs	(2,473,765)	
Remove ADIT Inj & Damages Res	190	3	(34,705,378)	SO	27.173%	(9,430,521)	

**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. The adjustment also recalculates the historical 10-year average Oregon-allocated property damage amount using the most recent 10-year time period. The June 2021 Oregon property reserve balance is also being amortized over 10 years. The insurance premiums in the base period have been adjusted to those in the Company's most current renewal.

**PacifiCorp  
 Oregon General Rate Case - December 2023  
 Insurance Expense  
 Injuries and Damages in Unadjusted Results**

Amount in Unadjusted Results

G/L Account	<u>Account Title</u>	<u>Allocator</u>	<u>Amount</u>
	Net Base Year Expense	SO	<u><b>139,344,910</b></u>
			<b>Ref 4.5</b>
545052	Inj/Damage Ins Prov - OR	OR	<b>1,484,743</b>
			<b>Ref 4.5</b>

Injuries & Damages Reserve

			<b>EOP Balance</b>
			<b>Jun-21</b>
	Net Base Year Reserve	SO	<u><b>(141,155,665)</b></u> <b>Ref 4.5</b>



**PacifiCorp  
Oregon General Rate Case - December 2023  
Insurance Expense  
Provision for Injuries & Damages  
3-Year Average Cash Paid**

	<u>Cash Paid - Injuries &amp; Damages</u>				<u>Third Party Insurance Claim Proceeds</u>			
	<u>Cash Expense</u>	<u>Amount not Seeking Recovery</u>	<u>3 - Year Avg to Recover</u>		<u>Claim Proceeds</u>	<u>Amount not Seeking Recovery</u>	<u>3 - Year Avg to Recover</u>	
12 Months Ended June 2019	3,413,952	51,750		(76,250)	(76,250)			
12 Months Ended June 2020	11,469,351	-		-	-			
12 Months Ended June 2021	2,929,134	-		-	-			
<b>Average Cash</b>	5,937,479	17,250	5,920,229	(25,417)	(25,417)	-	Below	
3 Year Average of Cash Paid for Injuries & Damages Reserve			5,920,229				Above	
3 Year Average of Cash Paid for Insurance Recovery			-				Above	
3 Year Normalized Average			5,920,229					
Oregon SO Allocation %			27.173%					
<b>Oregon Allocated Annual Accrual</b>			<u><u>1,608,709</u></u>					
			<b>Ref 4.5</b>					

**PacifiCorp  
Oregon General Rate Case - December 2023  
Insurance Expense  
Provision for Property Damages  
10-Year Average**

	<b>Actual Losses</b>			<b>Escalate to 2023</b>		
	System Transmission Losses	Oregon Distribution Losses	System Non-T&D Losses	End CPI-U Index	% Increase	2021
June 2011				225.722		
July 2011 - June 2012	411,470	7,582,565	86,000	229.478	1.66%	127.336%
July 2012 - June 2013	426,385	5,225,455	222,065	233.504	1.75%	125.252%
July 2013 - June 2014	163,517	4,472,174	2,297,475	238.343	2.07%	123.092%
July 2014 - June 2015	489,976	5,264,976	87,189	238.638	0.12%	120.593%
July 2015 - June 2016	440,896	9,217,139	1,272,026	241.018	1.00%	120.444%
July 2016 - June 2017	1,138,848	15,638,087	1,274,291	244.955	1.63%	119.255%
July 2017 - June 2018	1,087,346	2,629,908	39,747	251.989	2.87%	117.338%
July 2018 - June 2019	2,589,430	13,633,167	481,817	256.143	1.65%	114.063%
July 2019 - June 2020	976,712	8,743,858	90,409	257.797	0.65%	112.213%
July 2020 - June 2021	1,519,768	16,305,116	-	271.696	5.39%	111.493%
July 2021 - December 2023				287.426	5.79%	105.789%

	<b>Actual Losses Escalated to CY 2023</b>		
	System Transmission Losses	Oregon Distribution Losses	System Non-T&D Losses
July 2011 - June 2012	523,950	9,655,342	109,509
July 2012 - June 2013	534,055	6,544,983	278,141
July 2013 - June 2014	201,277	5,504,904	2,828,016
July 2014 - June 2015	590,878	6,349,206	105,144
July 2015 - June 2016	531,033	11,101,507	1,532,081
July 2016 - June 2017	1,358,131	18,649,172	1,519,654
July 2017 - June 2018	1,275,871	3,085,884	46,638
July 2018 - June 2019	2,953,575	15,550,365	549,574
July 2019 - June 2020	1,095,997	9,811,739	101,451
July 2020 - June 2021	1,694,435	18,179,061	-
Total in 2023 \$	10,759,202	104,432,164	7,070,208
10 Year Average	1,075,920	10,443,216	707,021
Oregon Allocation Factor	SG	Situs	SG
Oregon Allocation %	26.070%	100%	26.070%
June 2021 - Oregon Allocated 10 Year Average	280,496	10,443,216	184,323
UE - 374 - Oregon Allocated 10 Year Average	245,732	8,087,431	269,375
<b>Adjustment</b>	<b>34,764</b> <b>Ref 4.5</b>	<b>2,355,785</b> <b>Ref 4.5</b>	<b>(85,052)</b> <b>Ref 4.5</b>

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Insurance Expense**  
**Property Damage Reserve - Amortize the June 2021 EOP Balance Over 10 Years**

<u>OR Property Damages Reserve</u>		<b>EOP Balance</b>
288712	Reg Liab - OR Property Insurance Reserve	<b>Jun-21</b>
		<u>20,937,606</u>
	Annual Amount per Year	<b>2,093,761 Ref 4.5</b>

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Insurance Expense**  
**Adjust Base Period Liability Insurance Premium to CY 2021/2022 Level**

Adjusting the insurance premium in the base period to the renewed amount effective August 15, 2021

	<b>Premium Renewal <u>2021/2022</u></b>	<b>Included in Results 12 Months Ended <u>Jun-21</u></b>	<b><u>Adjustment</u></b>	
Excess Liability Insurance Premium	29,182,860	8,390,777	<b>20,792,083</b>	<b>Ref 4.5</b>
Property Insurance Premium	4,127,137	4,886,099	<b>(758,963)</b>	<b>Ref 4.5</b>
	<b>33,309,997</b>			

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Generation Overhaul Expense**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Generation Overhaul Expense - Steam	510	1	569,022	SG	26.070%	148,346	4.6.1
Generation Overhaul Expense - Other	553	1	<u>3,163,574</u>	SG	26.070%	<u>824,755</u>	4.6.1
			<u>3,732,596</u>			<u>973,101</u>	

**Description of Adjustment:**

This adjustment normalizes generation overhaul expenses in the 12 months ended June 2021 using a four-year average methodology. In this adjustment, overhaul expenses from July 2017 - June 2021 are restated in constant dollars to a June 2021 level using industry specific indices and then those constant dollars are averaged. The actual overhaul costs for the 12 months ended June 2021 are subtracted from the four-year average which results in this adjustment.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Generation Expense Normalization**

**FUNCTION: STEAM**

<b>Period</b>	<b>Overhaul Expense</b>	<b>Less Cholla</b>	<b>Overhaul Expense less Cholla</b>	<b>Restate to Constant Dollars (1)</b>	<b>Constant Dollars</b>
12 Months Ended June 2018	26,282,886	(3,205,000)	23,077,886	10.26%	25,446,076
12 Months Ended June 2019	32,510,459	(52,000)	32,458,459	6.64%	34,614,331
12 Months Ended June 2020	24,450,349	-	24,450,349	4.68%	25,595,197
12 Months Ended June 2021	27,793,172	-	27,793,172	0.00%	27,793,172
4 Year Average - Steam					28,362,194

12 Months Ended June 2021 Overhaul Expense - Steam	27,793,172	<b>Ref. 4.6.2</b>
<b>Adjustment</b>	<b>569,022</b>	<b>Ref. 4.6</b>

**FUNCTION: OTHER**

<b>Period</b>	<b>Overhaul Expense</b>	<b>Restate to Constant Dollars (1)</b>	<b>Constant Dollars</b>
12 Months Ended June 2018	5,647,997	8.78%	6,143,831
12 Months Ended June 2019	2,093,159	5.68%	2,212,147
12 Months Ended June 2020	10,103,281	3.62%	10,469,199
12 Months Ended June 2021	2,056,960	0.00%	2,056,960
4 Year Average			5,220,534

12 Months Ended June 2021 Overhaul Expense - Other	2,056,960	<b>Ref. 4.6.2</b>
<b>Adjustment</b>	<b>3,163,574</b>	<b>Ref. 4.6</b>

**Total Adjustment** **3,732,596** **Ref. 4.6**

(1) Ref. 4.6.3

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Generation Expense Normalization**

<b><u>Existing Units</u></b>	12 ME June 2018	12 ME June 2019	12 ME June 2020	12 ME June 2021	
<b><u>Steam Production</u></b>					
Blundell	248,814	251,321	42,023	1,664,859	
Dave Johnston	5,262,270	9,567,670	120,060	4,973,811	
Gadsby	70,424	592,107	90,772	1,026,066	
Hunter	8,450,624	6,164,112	9,739,253	242,353	
Huntington	-	8,850,109	12,579,293	20,018	
Jim Bridger	6,745,315	5,927,310	467,066	8,586,277	
Naughton	109,439	828	1,285,882	5,456,306	
Wyodak	-	-	-	-	
Cholla	3,205,000	52,000	-	-	
Colstrip	34,000	-	-	3,629,152	
Craig	819,000	1,105,000	126,000	1,350,355	
Hayden	1,338,000	-	-	843,976	
<b>Subtotal - Steam</b>	<b>26,282,886</b>	<b>32,510,459</b>	<b>24,450,349</b>	<b>27,793,172</b>	<b>Ref 4.6.1</b>
<b>Total Steam Production</b>	<b>26,282,886</b>	<b>32,510,459</b>	<b>24,450,349</b>	<b>27,793,172</b>	
<b><u>Other Production</u></b>					
Hermiston	1,368,000	2,028,897	3,453,637	1,339,432	
Currant Creek	9,809	5	1,703,462	89,493	
Lake Side	3,834,517	(154,086)	4,849,015	414,565	
Gadsby Peakers	-	29,376	-	-	
Chehalis	435,670	188,968	97,167	213,470	
<b>Total - Other Production</b>	<b>5,647,997</b>	<b>2,093,159</b>	<b>10,103,281</b>	<b>2,056,960</b>	<b>Ref 4.6.1</b>
<b>Grand Total</b>	<b>31,930,883</b>	<b>34,603,618</b>	<b>34,553,631</b>	<b>29,850,132</b>	

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Generation Expense Normalization**

<b>STEAM:</b>	<u>June 2018</u>	<u>June 2019</u>	<u>June 2020</u>	<u>June 2021</u>
Percentage Change to June 2021	10.26%	6.64%	4.68%	0.00%
<b>OTHER:</b>	<u>June 2018</u>	<u>June 2019</u>	<u>June 2020</u>	<u>June 2021</u>
Percentage Change to June 2021	8.78%	5.68%	3.62%	0.00%



**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Revenue-Sensitive Items & Uncollectibles**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Uncollectible Expense	904	3	(274,522)	OR	Situs	(274,522)	4.7.1
Other Taxes	408	3	(1,473,948)	OR	Situs	(1,473,948)	4.7.1
Regulatory Commission Exp	928	3	(227,655)	OR	Situs	(227,655)	4.7.1

**Description of Adjustment:**

This adjusts the Company's actual June 2021 uncollectible accounts expense to the December 2023 pro forma period by applying the unadjusted uncollectible rate (unadjusted uncollectible accounts expense/unadjusted general business revenues) to the normalized level of general business revenues. This adjustment also reflects an impact to other tax expense based on the normalized level of general business revenues and a three year historical average of the tax rates, per Commission Order UE-374.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Revenue Sensitive Items & Uncollectibles**

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Unadjusted Revenue	1,308,339,123	
Normalized Revenue	1,247,631,024	
Adjustments	<u>(60,708,099)</u>	
Uncollectible Expense in Base Period	5,916,318	
Uncollectible %	0.452%	
<b>Uncollectible Expense</b>	<b>(274,522)</b>	<b>Ref. 4.7</b>
Franchise Tax %	<b>2.3028%</b>	<b>Ref. 4.7.2</b>
Resource Supplier Tax %	<b>0.1252%</b>	<b>Ref. 4.7.2</b>
<b>Other Tax Expense</b>	<b>(1,473,948)</b>	<b>Ref. 4.7</b>
PUC Fees %	0.375%	
<b>PUC Fees Expense</b>	<b>(227,655)</b>	<b>Ref. 4.7</b>

**PacifiCorp  
Oregon General Rate Case - December 2023  
Revenue Sensitive Items & Uncollectibles**

**Three-Year Average Franchise Tax Rate**

	Composite Rate	2021	2020	2019	
Sales to Ultimate Consumers		\$ 1,289,111,435	\$ 1,293,711,531	\$ 1,270,397,389	(a)
Franchise Tax Expense		\$ 28,789,240	\$ 29,678,090	\$ 30,247,957	(b)
Franchise Tax Factor (2019-2021 Avg.- Last 3 Years)	<b>2.303%</b> Ref. 4.7.1 1/3(d) +1/3(e) + 1/3(f)	2.233%	2.294%	2.381%	(c) = (b)/(a)

**Three-Year Average ODOE (Resource Supplier Fees) Rate**

	Composite Rate	2021	2020	2019	
Gross Operating Revenue Subject to Assessment		\$ 1,307,954,317	\$ 1,328,949,705	\$ 1,285,011,449	(a)
Energy Resource Supplier Assessment		\$ 1,692,493	\$ 1,720,165	\$ 1,499,200	(b)
Oregon Department of Energy Tax Factor (2019-2021 Avg.- Last 3 Years)	<b>0.125%</b> Ref. 4.7.1 1/3(d) +1/3(e) + 1/3(f)	0.129%	0.129%	0.117%	(c) = (b)/(a)

**PacifiCorp  
Oregon General Rate Case - December 2023  
Membership & Subscriptions**

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	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Remove Total Memberships and Subscriptions</b>							
	930	1	(1,650,248)	SO	27.173%	(448,423)	
	930	1	(130)	OR	Situs	(130)	
Total			<u>(1,650,378)</u>			<u>(448,553)</u>	4.8.1
<b>Add Back 75% of National &amp; Regional Memberships</b>							
Various	930	1	<u>1,113,129</u>	SO	27.173%	<u>302,471</u>	
Total			<u>1,113,129</u>			<u>302,471</u>	4.8.2

**Description of Adjustment:**

This adjustment removes expenses in excess of Commission policy allowances as stated in the Commission order in UE-94. National and regional trade organizations are recognized at 75%. Western Electricity Coordinating Council and Northern Tier Transmission Group fees are included at 100%. The dues for these two organizations are no longer included in FERC account 930, but are now being booked to FERC account 561, and are not shown in this adjustment.

PacifiCorp  
Oregon General Rate Case - December 2023  
Memberships and Subscriptions

Account	Factor	Description	Amount	
<b>Remove Total Memberships and Subscriptions in Account 930.2</b>				
930.2	SO	Included in Unadjusted Results	(1,650,248)	
930.2	OR	Included in Unadjusted Results	(130)	
			<u>(1,650,378)</u>	<b>Ref 4.8</b>
<b>Allowed National and Regional Trade Memberships at 75%</b>				
930.2	SO	Albany Area Chamber of Commerce	2,225	
930.2	SO	Albany Downtown Association & Park Wise	180	
930.2	SO	American Wind Wildlife Institute	23,333	
930.2	SO	Astoria Downtown Historic District Association	500	
930.2	SO	Bay Area Chamber of Commerce	1,019	
930.2	SO	Bend Chamber of Commerce	1,725	
930.2	SO	Cannon Beach Chamber of Commerce	310	
930.2	SO	Central Point Chamber of Commerce	250	
930.2	SO	Clatsop Economic Development Resources	5,000	
930.2	SO	Columbia Corridor Association	3,000	
930.2	SO	Columbia River Maritime Museum	500	
930.2	SO	Common Ground Alliance	2,500	
930.2	SO	Corvallis Chamber of Commerce	3,500	
930.2	SO	Cottage Grove Chamber of Commerce	300	
930.2	SO	Dallas Area Visitors Center	600	
930.2	SO	Douglas Timber Operators	600	
930.2	SO	East-Linn Utilities Coordinating Council	125	
930.2	SO	Economic Development for Central Oregon	7,500	
930.2	SO	Edison Electric Institute	988,312	
930.2	SO	Energy Storage Association	3,375	
930.2	SO	Energy Systems Integration Group	1,618	
930.2	SO	Forth (Drive Oregon)	1,500	
930.2	SO	Grants Pass Josephine County Chamber of Commerce	275	
930.2	SO	Greater Albany Rotary Club	281	
930.2	SO	GridForward	5,000	
930.2	SO	Intermountain Electrical Association	9,500	
930.2	SO	International Economic Development Council	455	
930.2	SO	Klamath County Chamber of Commerce	799	
930.2	SO	Klamath County Economic Development Association	5,000	
930.2	SO	Klamath Forest Protective Association	26	
930.2	SO	Lake County Chamber of Commerce	500	
930.2	SO	Lane Utilities Coordinating Council	100	
930.2	SO	League of Oregon Cities	600	
930.2	SO	Lebanon Area Chamber of Commerce	1,600	
930.2	SO	Linkville Kiwanis Club-Klamath Falls	115	
930.2	SO	Linn-Benton Utilities Coordinating Council	125	
930.2	SO	Madras Jefferson County Chamber	385	
930.2	SO	Madras-Jefferson County Chamber of Commerce	385	
930.2	SO	Metropolitan Utility Coordinating Council	150	
930.2	SO	Monmouth- Independence Chamber of Commerce	1,200	
930.2	SO	Myrtle Creek-Tri City Area Chamber of Commerce	105	
930.2	SO	North American Transmission Forum	95,167	
930.2	SO	North Santiam Chamber of Commerce	1,000	
930.2	SO	Northwest Hydroelectric Association	1,200	
930.2	SO	Northwest Public Power Association	185	
930.2	SO	Oregon Business Council	24,879	
930.2	SO	Oregon Energy Fund	75	
930.2	SO	Oregon State University, Utility Pole Research Cooperative	15,000	
930.2	SO	Pacific Northwest Utilities Conference Committee	118,788	
930.2	SO	Pendleton Chamber of Commerce	635	
930.2	SO	Pilot Rock Chamber of Commerce	50	
930.2	SO	Portland Business Alliance: Partners in Diversity	36,243	
930.2	SO	Princeville Chamber of Commerce	240	
930.2	SO	Redmond Economic Development, Inc.	5,000	
930.2	SO	Rocky Mountain Electrical League	18,000	
930.2	SO	Roseburg Area Chamber of Commerce	1,090	
930.2	SO	Rotary Club of Albina	225	
930.2	SO	Rotary Club of Roseburg	345	
930.2	SO	Seaside Chamber of Commerce	395	
930.2	SO	Seaside Downtown Development Association	175	
930.2	SO	South Lincoln County Economic Development Corporation	1,000	
930.2	SO	Southern Oregon Regional Economic Development, Inc.	2,500	
930.2	SO	Sport Oregon	5,000	
930.2	SO	Stayton-Sublimity Chamber of Commerce	2,149	
930.2	SO	Strategic Economic Development Corporation	1,400	
930.2	SO	Sutherlin Chamber of Commerce	125	
930.2	SO	Takena Kiwanis	130	
930.2	SO	The Chamber of Medford/Jackson County	2,247	
930.2	SO	The Enterprise	750	
930.2	SO	The National Hydropower Association, Inc.	45,384	

**PacifiCorp  
Oregon General Rate Case - December 2023  
Memberships and Subscriptions**

<b>Account</b>	<b>Factor</b>	<b>Description</b>	<b>Amount</b>
930.2	SO	Tri-County Chamber of Commerce	255
930.2	SO	Umpqua Economic Development Partnership	2,500
930.2	SO	Umpqua Lions Club	75
930.2	SO	Utility Economic Development Association, Inc.	745
930.2	SO	Western Energy Supply Transmission Associates	20,548
930.2	SO	Western Labor And Management Public Affairs Committee	4,000
930.2	SO	Women's Energy Network	2,100
			<u><b>1,484,172</b></u>

**Allowed Memberships and Subscriptions - 75% of amount above 1,113,129 Ref 4.8**

PacifiCorp  
Oregon General Rate Case - December 2023  
Meals and Entertainment Adjustment

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Disallowance Removal	500	1	(53)	SG	26.070%	(14)	
	502	1	1	SG	26.070%	0	
	506	1	(1,586)	SG	26.070%	(413)	
	514	1	(22)	SG	26.070%	(6)	
	535	1	(53)	SG-P	26.070%	(14)	
	535	1	(2,222)	SG-U	26.070%	(579)	
	539	1	53	SG	26.070%	14	
	539	1	(0)	SG-U	26.070%	(0)	
	546	1	(12)	SG	26.070%	(3)	
	548	1	(278)	SG	26.070%	(72)	
	549	1	(2,310)	SG	26.070%	(602)	
	553	1	(514)	SG	26.070%	(134)	
	557	1	(13,561)	SG	26.070%	(3,535)	
	560	1	(892)	SG	26.070%	(233)	
	561	1	(142)	SG	26.070%	(37)	
	570	1	(0)	SG	26.070%	(0)	
	571	1	(0)	SG	26.070%	(0)	
	580	1	(2,728)	OR	Situs	(2,728)	
	580	1	(4,679)	SNPD	26.473%	(1,239)	
	581	1	(72)	SNPD	26.473%	(19)	
	585	1	(186)	SNPD	26.473%	(49)	
	588	1	1	OR	Situs	1	
	590	1	(7,290)	SNPD	26.473%	(1,930)	
	592	1	(1,620)	SNPD	26.473%	(429)	
	593	1	0	OR	Situs	0	
	593	1	(8,361)	SNPD	26.473%	(2,213)	
	595	1	(443)	SNPD	26.473%	(117)	
	598	1	(103)	SNPD	26.473%	(27)	
	901	1	(669)	CN	30.990%	(207)	
	903	1	(172)	CN	30.990%	(53)	
	908	1	(542)	CN	30.990%	(168)	
	908	1	(3,058)	OR	Situs	(3,058)	
	909	1	(578)	CN	30.990%	(179)	
	921	1	(9,661)	SO	27.173%	(2,625)	
			<u>(61,751)</u>			<u>(20,671)</u>	4.9.1

**Description of Adjustment:**

This adjustment removes the disallowance that was ordered by the Commission in Order UE 374 No. 20-473. The Commission ruled that all meals and entertainment expenses recognized as discretionary costs and all awards expense would be disallowed at 50%.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Meals & Entertainment Adjustment**  
**Summary of Adjustments**

Meals and Entertainment 50% Adjustment			Awards 50% Adjustment		
FERC Account	Allocation	Amount	FERC Account	Allocation	Amount
500	SG	106	506	SG	477
501	SE	-	548	SG	446
502	SG	(2)	560	SG	97
505	SG	-	903	CN	125
506	SG	2,694	921	SO	3,573
514	SG	43	929	SO	-
535	SG-P	105	Grand Total		4,718
535	SG-U	4,444			
537	SG-P	-			
539	SG-P	(107)			
539	SG-U	0			
546	SG	24			
548	SG	111	Meals & Entertainment	118,783	
549	OR	-	Disallowance	-50%	
549	SG	4,620	Removal	(59,392)	
553	SG	1,028			
557	SG	27,122	Awards	4,718	
560	SG	1,688	Disallowance	-50%	
561	SG	285	Removal	(2,359)	
568	SG	-			
569	SG	-	<b>Total Disallowance</b>	<b>(61,751)</b>	Ref 4.9
570	SG	0			
571	SG	0			
580	OR	5,457			
580	SNPD	9,358			
581	SNPD	143			
585	SNPD	373			
588	OR	(1)			
590	SNPD	14,580			
592	OR	-			
592	SNPD	3,241			
593	OR	(0)			
593	SNPD	16,721			
595	SNPD	886			
598	SNPD	205			
901	CN	1,337			
903	CN	218			
903	OR	-			
908	CN	1,084			
908	OR	6,117			
909	CN	1,155			
921	SO	15,750			
935	OR	-			
Grand Total		118,783			



**PacifiCorp  
Oregon General Rate Case - December 2023  
O&M Expense Escalation**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Steam Operations	500	3	19,118	SG	26.070%	4,984	
Steam Operations	500	3	88,937	SG	26.070%	23,186	
Steam Operations	501	3	1,374,066	SE	25.068%	344,453	
Steam Operations	501	3	21,692	SE	25.068%	5,438	
Steam Operations	501	3	509,037	OR	Situs	403,598	
Steam Operations	502	3	4,621,099	SG	26.070%	1,204,736	
Steam Operations	502	3	378,684	SG	26.070%	98,724	
Steam Operations	503	3	(7,339)	SE	25.068%	(1,840)	
Steam Operations	505	3	-	SG	26.070%	-	
Steam Operations	505	3	79,942	SG	26.070%	20,841	
Steam Operations	505	3	10,757	SG	26.070%	2,804	
Steam Operations	506	3	(4,102,827)	SG	26.070%	(1,069,621)	
Steam Operations	506	3	2,214,631	SG	26.070%	577,362	
Steam Operations	506	3	118,803	SG	26.070%	30,972	
Steam Operations	507	3	-	SG	26.070%	-	
Steam Operations	507	3	38,270	SG	26.070%	9,977	
Steam Operations	507	3	19	SG	26.070%	5	
Steam Maintenance	510	3	39,841	SG	26.070%	10,387	
Steam Maintenance	510	3	101,935	SG	26.070%	26,575	
Steam Maintenance	510	3	74,514	SG	26.070%	19,426	
Steam Maintenance	511	3	971,654	SG	26.070%	253,313	
Steam Maintenance	511	3	178,479	SG	26.070%	46,530	
Steam Maintenance	512	3	-	SG	26.070%	-	
Steam Maintenance	512	3	3,120,202	SG	26.070%	813,447	
Steam Maintenance	512	3	122,102	SG	26.070%	31,832	
Steam Maintenance	513	3	-	SG	26.070%	-	
Steam Maintenance	513	3	1,412,947	SG	26.070%	368,360	
Steam Maintenance	513	3	21,061	SG	26.070%	5,491	
Steam Maintenance	514	3	583,815	SG	26.070%	152,203	
Steam Maintenance	514	3	102,387	SG	26.070%	26,693	
Hydro Operations	535	3	397,265	SG	26.070%	103,568	
Hydro Operations	535	3	(162,715)	SG	26.070%	(42,420)	
Hydro Operations	536	3	21,672	SG	26.070%	5,650	
Hydro Operations	536	3	-	SG	26.070%	-	
Hydro Operations	537	3	345,922	SG	26.070%	90,183	
Hydro Operations	537	3	27,466	SG	26.070%	7,160	
Hydro Operations	539	3	510,190	SG	26.070%	133,008	
Hydro Operations	539	3	149,763	SG	26.070%	39,044	
Hydro Operations	539	3	5	SG	26.070%	1	
Hydro Operations	540	3	135,640	SG	26.070%	35,362	
Hydro Operations	540	3	6,055	SG	26.070%	1,579	
			<u>13,525,091</u>			<u>3,783,013</u>	

**Description of Adjustment:**

This adjustment calculates the non-labor O&M escalation from June 2021 to December 2023 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2021 actual data was separated into labor and non-labor components and costs that should not be included in June 2021 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 2023**  
**(cont.) O&M Expense Escalation**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Hydro Maintenance	541	3	28	SG	26.070%	7	
Hydro Maintenance	541	3	-	SG	26.070%	-	
Hydro Maintenance	542	3	30,367	SG	26.070%	7,917	
Hydro Maintenance	542	3	1,912	SG	26.070%	499	
Hydro Maintenance	543	3	27,439	SG	26.070%	7,153	
Hydro Maintenance	543	3	15,397	SG	26.070%	4,014	
Hydro Maintenance	544	3	50,023	SG	26.070%	13,041	
Hydro Maintenance	544	3	5,672	SG	26.070%	1,479	
Hydro Maintenance	545	3	149,610	SG	26.070%	39,004	
Hydro Maintenance	545	3	46,778	SG	26.070%	12,195	
Hydro Maintenance	545	3	-	SG	26.070%	-	
Other Operations	546	3	27,446	SG	26.070%	7,155	
Other Operations	546	3	(1)	SG	26.070%	(0)	
Other Operations	547	3	-	SE	25.068%	-	
Other Operations	548	3	(24)	SG	26.070%	(6)	
Other Operations	547	3	-	SE	25.068%	-	
Other Operations	548	3	1,055,932	SG	26.070%	275,285	
Other Operations	548	3	23,782	SG	26.070%	6,200	
Other Operations	549	3	1,157	OR	Situs	1,157	
Other Operations	549	3	(2,683)	SG	26.070%	(699)	
Other Operations	549	3	(1,201)	SG	26.070%	(313)	
Other Operations	549	3	363,216	SG	26.070%	94,692	
Other Operations	550	3	32,953	OR	Situs	32,953	
Other Operations	550	3	-	SG	26.070%	-	
Other Operations	550	3	3,559	SG	26.070%	928	
Other Operations	550	3	647,675	SG	26.070%	168,851	
Other Operations	550	3	-	SG	26.070%	-	
Other Maintenance	552	3	-	SG	26.070%	-	
Other Maintenance	552	3	89,083	SG	26.070%	23,224	
Other Maintenance	552	3	1,159	SG	26.070%	302	
Other Maintenance	553	3	143,506	SG	26.070%	37,413	
Other Maintenance	553	3	741,438	SG	26.070%	193,295	
Other Maintenance	553	3	163,220	SG	26.070%	42,552	
Other Maintenance	553	3	10,225	SG	26.070%	2,666	
Other Maintenance	554	3	-	SG	26.070%	-	
Other Maintenance	554	3	69,933	SG	26.070%	18,232	
Other Maintenance	554	3	140,760	SG	26.070%	36,697	
Other Maintenance	554	3	2,546	SG	26.070%	664	
			<u>3,840,907</u>			<u>1,026,555</u>	

**Description of Adjustment:**

This adjustment calculates the non-labor O&M escalation from June 2021 to December 2023 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2021 actual data was separated into labor and non-labor components and costs that should not be included in June 2021 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 2023**  
**(cont.) O&M Expense Escalation**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Other Operations	556	3	28,994	SG	26.070%	7,559	
Other Operations	557	3	594,109	OR	Situs	266,179	
Other Operations	557	3	520,616	SG	26.070%	135,726	
Other Operations	557	3	746	SE	25.068%	187	
Other Operations	557	3	-	SG	26.070%	-	
Transmission Operations	560	3	23,182	SG	26.070%	6,044	
Transmission Operations	560	3	(41)	SG	26.070%	(11)	
Transmission Operations	561	3	330,817	SG	26.070%	86,245	
Transmission Operations	561	3	(7)	SG	26.070%	(2)	
Transmission Operations	562	3	69,347	SG	26.070%	18,079	
Transmission Operations	563	3	21,063	SG	26.070%	5,491	
Transmission Operations	566	3	163,442	SG	26.070%	42,610	
Transmission Operations	567	3	110,085	SG	26.070%	28,699	
Transmission Maintenance	568	3	(3,212)	SG	26.070%	(837)	
Transmission Maintenance	569	3	207,778	SG	26.070%	54,168	
Transmission Maintenance	570	3	335,311	SG	26.070%	87,417	
Transmission Maintenance	571	3	1,176,963	SG	26.070%	306,838	
Transmission Maintenance	571	3	(181,711)	SG	26.070%	(47,373)	
Transmission Maintenance	572	3	9,930	SG	26.070%	2,589	
Transmission Maintenance	573	3	14,801	SG	26.070%	3,859	
Distribution Operations	580	3	63,842	OR	Situs	8,153	
Distribution Operations	580	3	42,639	SNPD	26.473%	11,288	
Distribution Operations	581	3	-	OR	Situs	-	
Distribution Operations	581	3	(12,098)	SNPD	26.473%	(3,203)	
Distribution Operations	582	3	189,934	OR	Situs	59,179	
Distribution Operations	582	3	1,217	SNPD	26.473%	322	
Distribution Operations	583	3	161,279	OR	Situs	34,340	
Distribution Operations	583	3	0	SNPD	26.473%	0	
Distribution Operations	584	3	31	OR	Situs	31	
Distribution Operations	584	3	-	SNPD	26.473%	-	
Distribution Operations	585	3	5,576	SNPD	26.473%	1,476	
Distribution Operations	586	3	39,958	OR	Situs	18,458	
Distribution Operations	586	3	-	SNPD	26.473%	-	
Distribution Operations	587	3	288,809	OR	Situs	98,573	
Distribution Operations	587	3	-	SNPD	26.473%	-	
Distribution Operations	588	3	23,252	OR	Situs	(3,441)	
Distribution Operations	588	3	(141,447)	SNPD	26.473%	(37,445)	
Distribution Operations	589	3	220,246	OR	Situs	132,052	
Distribution Operations	589	3	1,903	SNPD	26.473%	504	
			<u>4,307,357</u>			<u>1,323,756</u>	

**Description of Adjustment:**

This adjustment calculates the non-labor O&M escalation from June 2021 to December 2023 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2021 actual data was separated into labor and non-labor components and costs that should not be included in June 2021 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 2023  
(cont.) O&M Expense Escalation**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Distribution Maintenance	590	3	28,963	OR	Situs	10,164	
Distribution Maintenance	590	3	(2,788)	SNPD	26.473%	(738)	
Distribution Maintenance	591	3	146,493	OR	Situs	41,741	
Distribution Maintenance	591	3	4,945	SNPD	26.473%	1,309	
Distribution Maintenance	592	3	162,579	OR	Situs	60,078	
Distribution Maintenance	592	3	19,019	SNPD	26.473%	5,035	
Distribution Maintenance	593	3	(770,503)	OR	Situs	(1,308,306)	
Distribution Maintenance	593	3	(79,436)	SNPD	26.473%	(21,029)	
Distribution Maintenance	594	3	1,352,799	OR	Situs	267,443	
Distribution Maintenance	594	3	401	SNPD	26.473%	106	
Distribution Maintenance	595	3	-	OR	Situs	-	
Distribution Maintenance	595	3	11,806	SNPD	26.473%	3,125	
Distribution Maintenance	596	3	73,071	OR	Situs	20,627	
Distribution Maintenance	597	3	13,154	OR	Situs	3,407	
Distribution Maintenance	597	3	8,079	SNPD	26.473%	2,139	
Distribution Maintenance	598	3	114,616	OR	Situs	(22,788)	
Distribution Maintenance	598	3	510,978	SNPD	26.473%	135,269	
Customer Accounts Operations	901	3	62	OR	Situs	-	
Customer Accounts Operations	901	3	57,410	CN	30.990%	17,791	
Customer Accounts Operations	902	3	336,764	OR	Situs	91,662	
Customer Accounts Operations	902	3	8,592	CN	30.990%	2,663	
Customer Accounts Operations	903	3	135,339	OR	Situs	45,383	
Customer Accounts Operations	903	3	1,426,201	CN	30.990%	441,979	
Customer Accounts Operations	904	3	1,204,875	OR	Situs	599,706	
Customer Accounts Operations	904	3	14,323	CN	30.990%	4,439	
Customer Accounts Operations	905	3	-	OR	Situs	-	
Customer Accounts Operations	905	3	2,584	CN	30.990%	801	
Customer Service Operations	907	3	4	CN	30.990%	1	
Customer Service Operations	908	3	143,654	OR	Situs	124,202	
Customer Service Operations	908	3	9,796	CN	30.990%	3,036	
Customer Service Operations	908	3	9,443,746	OTHER	0.000%	-	
Customer Service Operations	909	3	189,950	OR	Situs	67,492	
Customer Service Operations	909	3	85,185	CN	30.990%	26,399	
Customer Service Operations	910	3	-	OR	Situs	-	
Customer Service Operations	910	3	164	CN	30.990%	51	
			<u>14,652,825</u>			<u>623,186</u>	

**Description of Adjustment:**

This adjustment calculates the non-labor O&M escalation from June 2021 to December 2023 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2021 actual data was separated into labor and non-labor components and costs that should not be included in June 2021 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 2023**  
**(cont.) O&M Expense Escalation**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
A&G Operations	920	3	(41,808)	OR	Situs	(12,853)	
A&G Operations	920	3	50,175	SO	27.173%	13,634	
A&G Operations	921	3	6,431	CN	30.990%	1,993	
A&G Operations	921	3	172,499	OR	Situs	133,171	
A&G Operations	921	3	456,177	SO	27.173%	123,957	
A&G Operations	922	3	(607,195)	SO	27.173%	(164,994)	
A&G Operations	923	3	46,197	OR	Situs	10,155	
A&G Operations	923	3	1,004,185	SO	27.173%	272,868	
A&G Operations	924	3	-	SO	27.173%	-	
A&G Operations	925	3	-	SO	27.173%	-	
A&G Operations	926	3	(237,120)	SO	27.173%	(64,433)	
A&G Operations	926	3	358,654	OR	Situs	10,382	
A&G Operations	928	3	339,055	SG	26.070%	88,393	
A&G Operations	928	3	-	SO	27.173%	-	
A&G Operations	928	3	146,923	SO	27.173%	39,923	
A&G Operations	928	3	1,325,540	OR	Situs	434,107	
A&G Operations	929	3	(31,248)	SO	27.173%	(8,491)	
A&G Operations	930	3	1,076	OR	Situs	-	
A&G Operations	930	3	-	CN	30.990%	-	
A&G Operations	930	3	-	SG	26.070%	-	
A&G Operations	930	3	86,834	SO	27.173%	23,596	
A&G Operations	931	3	81,828	OR	Situs	36,065	
A&G Operations	931	3	163,396	SO	27.173%	44,400	
A&G Operations	935	3	18,831	OR	Situs	7,028	
A&G Operations	935	3	1,394	CN	30.990%	432	
A&G Operations	935	3	1,210,108	SO	27.173%	328,824	
			<u>4,551,932</u>			<u>1,318,158</u>	
			13,525,091			3,783,013	4.10
			3,840,907			1,026,555	4.10.1
			4,307,357			1,323,756	4.10.2
			14,652,825			623,186	4.10.3
			<u>4,551,932</u>			<u>1,318,158</u>	4.10.4
Total Adjustment			<u>40,878,111</u>			<u>8,074,669</u>	

**Description of Adjustment:**

This adjustment calculates the non-labor O&M escalation from June 2021 to December 2023 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2021 actual data was separated into labor and non-labor components and costs that should not be included in June 2021 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 2023  
O&M Expense Escalation

Function	Allocation Code																Escalation Percentages	4.10		
		4.1	4.2	4.4	4.5	4.6	4.8	4.9	4.11	4.13	5.1	8.9	8.10	8.13	O&M Escalation	O&M Escalation				
		Unadjusted O&M	Miscellaneous General Expenses & Revenue	emove & Benefits	Unadjst Non-Recurring	Remove Entries	Insurance Expense	Generation Overhaul Expense	Membership & Subscriptions	Meals and Entertainment Adjustment	Wildfire & Veg Management Expenses	Jim Bridger Units 1 & 2 O&M	Net Power Costs	Remove Rolling Hills	Deer Creek Mine Closure	Cholla Unit Retirement	O&M Before Escalation	Escalation Percentages	O&M Escalation	O&M After Escalation
Steam Operation																				
	NPICD	35,987	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35,987	0.00%	-	35,987
	NPCSE	642,488,321	-	-	-	-	-	-	-	-	-	-	-	-	-	-	642,488,321	0.00%	-	642,488,321
	NPCSSECH	31,040,758	-	-	-	-	-	-	-	-	-	-	-	-	-	-	31,040,758	0.00%	-	31,040,758
	NPCWYP	101,258	-	-	-	-	-	-	-	-	-	-	-	-	-	-	101,258	0.00%	-	101,258
	SE	16,755,152	-	(89,493)	-	-	-	-	-	-	-	-	-	-	-	-	16,665,660	8.20%	1,366,727	18,032,386
	SG	89,370,307	-	(32,788,194)	-	-	-	-	-	(1,585)	-	-	-	-	-	-	6,552,861	8.20%	537,391	7,090,251
	SNPPS	58,885,776	-	(30,439,434)	-	-	-	-	-	-	-	-	-	-	-	-	28,446,341	8.20%	2,332,843	30,779,185
	SSECH	264,509	-	-	-	-	-	-	-	-	-	-	-	-	-	-	264,509	8.20%	21,692	286,201
	SSGCH	7,282,240	-	-	-	-	-	-	-	(53)	-	-	-	-	-	-	7,282,187	8.20%	597,202	7,879,389
	CA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.20%	-	0
	ID	1,285,707	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,285,707	8.20%	105,439	1,391,146
	OR	4,921,418	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,921,418	8.20%	403,598	5,325,016
	WA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.20%	-	0
	WYP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.20%	-	0
	<b>Steam Operation Total</b>	<b>852,431,433</b>	-	<b>(63,317,121)</b>	-	-	-	-	-	<b>(1,838)</b>	-	-	-	-	<b>(35,379,413)</b>	<b>(14,648,254)</b>	<b>739,085,007</b>		<b>5,364,891</b>	<b>744,449,898</b>
Steam Maintenance																				
	SG	32,591,804	-	(10,375,976)	-	-	-	569,022	-	(22)	-	-	-	-	-	-	22,784,829	7.00%	1,595,310	24,380,139
	SNPPS	105,000,699	-	(38,800,647)	-	-	-	-	-	-	-	-	-	-	-	-	66,200,052	7.00%	4,635,084	70,835,136
	SSGCH	7,121,369	-	(987)	-	-	-	-	-	-	-	-	-	-	-	-	7,120,383	7.00%	498,543	7,618,926
	<b>Steam Maintenance Total</b>	<b>144,713,872</b>	-	<b>(49,177,610)</b>	-	-	-	<b>569,022</b>	-	<b>(22)</b>	-	-	-	-	-	-	<b>96,105,263</b>		<b>6,728,937</b>	<b>102,834,200</b>
Hydro Operations																				
	SG-P	27,122,423	-	(12,249,164)	-	-	-	-	-	(53)	-	-	-	-	-	-	14,873,206	9.48%	1,410,688	16,283,895
	SG-U	8,563,421	-	(8,344,338)	-	-	-	-	-	(2,222)	-	-	-	-	-	-	216,861	9.48%	20,569	237,430
	SG	-	-	-	-	-	-	-	-	53	-	-	-	-	-	-	-	9.48%	5	59
	<b>Hydro Operations Total</b>	<b>35,685,844</b>	-	<b>(20,593,502)</b>	-	-	-	-	-	<b>(2,221)</b>	-	-	-	-	-	-	<b>15,090,121</b>		<b>1,431,262</b>	<b>16,521,383</b>
Hydro Maintenance																				
	SG-P	6,069,764	-	(2,550,757)	-	-	-	-	-	-	-	-	-	-	-	-	3,519,007	7.32%	257,467	3,776,474
	SG-U	1,515,303	-	(561,855)	-	-	-	-	-	-	-	-	-	-	-	-	953,448	7.32%	69,759	1,023,207
	SG	33,000,000	-	-	(33,000,000)	-	-	-	-	-	-	-	-	-	-	-	-	7.32%	-	0
	<b>Hydro Maintenance Total</b>	<b>40,585,067</b>	-	<b>(3,112,612)</b>	<b>(33,000,000)</b>	-	-	-	-	-	-	-	-	-	-	-	<b>4,472,455</b>		<b>327,226</b>	<b>4,799,681</b>
Purchased Power																				
	NPCSE	62,781,784	-	-	-	-	-	-	-	-	-	-	-	-	-	-	62,781,784	0.00%	-	62,781,784
	NPCSG	621,018,560	-	-	-	-	-	-	-	-	-	-	(33,207,191)	-	-	-	587,811,369	0.00%	-	587,811,369
	NPICUT	10,277,762	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,277,762	0.00%	-	10,277,762
	OTHER	3,990,510	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,990,510	0.00%	-	3,990,510
	<b>Purchase Power Total</b>	<b>698,068,616</b>	-	-	-	-	-	-	-	-	-	-	<b>(33,207,191)</b>	-	-	-	<b>664,861,425</b>		-	<b>664,861,425</b>
Other Operations																				
	NPCSE	289,072,443	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289,072,443	0.00%	-	289,072,443
	NPCSSECT	1,980,087	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,980,087	0.00%	-	1,980,087
	SG-W	11,913,553	-	(327,547)	-	-	-	-	-	-	-	-	-	-	-	-	11,586,206	8.72%	1,010,891	12,597,097
	SNPPO	22,045,619	-	(9,601,596)	-	-	-	-	-	-	-	-	-	-	-	-	12,444,023	8.72%	1,085,735	13,529,758
	SSGCT	383,214	-	(110,639)	-	-	-	-	-	-	-	-	-	-	-	-	272,575	8.72%	23,782	296,357
	SE	8,552	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,552	8.72%	746	9,298
	SG	35,588,901	(2,509)	(29,273,546)	-	-	-	-	-	(16,161)	-	-	-	-	-	-	6,268,247	8.72%	546,902	6,815,149
	ID	3,738,628	-	(69,384)	-	-	-	-	-	-	-	-	-	-	-	-	3,669,244	8.72%	320,140	3,989,384
	OR	3,460,857	-	(19,124)	-	-	-	-	-	-	-	-	-	-	-	-	3,441,733	8.72%	300,290	3,742,022
	UT	35,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35,000	8.72%	3,054	38,054
	WYU	54,288	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54,288	8.72%	4,737	59,025
	<b>Other Operations Total</b>	<b>368,281,143</b>	<b>(2,509)</b>	<b>(39,401,637)</b>	-	-	-	-	-	<b>(16,161)</b>	-	-	-	<b>(28,437)</b>	-	-	<b>328,832,398</b>		<b>3,296,276</b>	<b>332,128,674</b>
Other Maintenance																				
	SNPPO	8,200,376	-	(2,584,230)	-	-	-	-	-	-	-	-	-	-	-	-	5,616,147	7.00%	393,064	6,009,210
	SSGCT	363,813	-	(164,782)	-	-	-	-	-	-	-	-	-	-	-	-	199,031	7.00%	13,930	212,961
	SG	-	-	-	-	-	-	3,163,574	-	(614)	-	-	-	-	-	-	2,050,439	7.00%	143,506	2,193,945
	SG-W	12,082,666	-	(489,692)	-	-	-	-	-	-	-	-	-	-	-	-	11,592,974	7.00%	811,371	12,404,344
	<b>Other Maintenance Total</b>	<b>20,646,854</b>	-	<b>(3,238,703)</b>	-	-	-	<b>3,163,574</b>	-	<b>(514)</b>	-	-	-	<b>(1,112,621)</b>	-	-	<b>19,458,590</b>		<b>1,361,870</b>	<b>20,820,461</b>
Transmission Operations																				
	NPCSE	15,971,607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,971,607	0.00%	-	15,971,607
	NPCSG	133,395,046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	133,395,046	0.00%	-	133,395,046
	SG	-	-	-	-	-	-	-	-	(1,035)	-	-	-	-	-	-	(1,035)	4.62%	(48)	(1,083)
	SNPT	37,042,928	-	(21,517,866)	-	-	-	-	-	-	-	-	-	-	-	-	15,525,062	4.62%	717,936	16,242,998
	<b>Transmission Operations Total</b>	<b>186,409,581</b>	-	<b>(21,517,866)</b>	-	-	-	-	-	<b>(1,035)</b>	-	-	-	-	-	-	<b>164,890,681</b>		<b>717,888</b>	<b>165,608,569</b>
Transmission Maintenance																				
	SNPT	34,418,467	-	(13,582,092)	-	-	-	-	-	-	-	-	-	-	-	-	20,836,375	8.36%	1,741,572	22,577,946
	SG	-	-	-	-	-	-	-	-	(0)	(2,174,016)	-	-	-	-	-	(2,174,016)	8.36%	(181,711)	(2,355,727)
	<b>Transmission Maintenance Total</b>	<b>34,418,467</b>	-	<b>(13,582,092)</b>	-	-	-	-	-	<b>(0)</b>	<b>(2,174,016)</b>	-	-	-	-	-	<b>18,662,358</b>		<b>1,559,860</b>	<b>20,222,219</b>
Distribution Operations																				
	CA	1,796,696	-	(1,190,497)	-	-	-	-	-	-	-	-	-	-	-	-	606,199	7.51%	45,552	651,751
	ID	1,672,891	-	(1,199,369)	-	-	-	-	-	-	-	-	-	-	-	-	473,522	7.51%	35,582	509,105
	OR	12,695,790	-	(8,070,673)	-	-														

PacifiCorp  
Oregon General Rate Case - December 2023  
O&M Expense Escalation

Function	Allocation Code	Unadjusted O&M	4.1	4.2	4.4	4.5	4.6	4.8	4.9	4.11	4.13	5.1	8.9	8.10	8.13	O&M		4.10	O&M	
			Miscellaneous General Expenses & Revenue	emove Unadj Employees Benefits	Remove Non-Recurring Entries	Insurance Expense	Generation Overhaul Expense	Membership & Subscriptions	Meals and Entertainment Adjustment	Wildfire & Veg Management Expenses	Jim Bridger Units 1 & 2 O&M	Net Power Costs	Remove Rolling Hills	Deer Creek Mine Closure	Cholla Unit Retirement	Escalation Before Escalation	Escalation Percentages	O&M Escalation	O&M After Escalation	
<b>Distribution Maintenance</b>																				
CA		10,043,545	-	(5,634,612)	-	-	-	-	-	-	-	-	-	-	-	-	4,408,933	8.34%	367,790	4,776,723
ID		5,669,727	-	(5,542,568)	-	-	-	-	-	-	-	-	-	-	-	-	127,159	8.34%	10,608	137,766
OR		66,832,280	-	(35,311,590)	-	-	-	-	0	(42,640,829)	-	-	-	-	-	-	(11,120,139)	8.34%	(927,634)	(12,047,773)
SNPD		12,340,220	-	(5,105,331)	-	-	-	-	(17,817)	(1,546,887)	-	-	-	-	-	-	5,670,185	8.34%	473,003	6,143,188
UT		53,369,512	-	(37,188,816)	-	-	-	-	-	-	-	-	-	-	-	-	16,180,696	8.34%	1,349,782	17,530,479
WA		8,487,156	-	(5,871,447)	-	-	-	-	-	-	-	-	-	-	-	-	2,615,708	8.34%	218,201	2,833,909
WYP		9,463,181	-	(8,661,524)	-	-	-	-	-	-	-	-	-	-	-	-	801,657	8.34%	66,874	868,531
WYU		1,179,856	-	(753,688)	-	-	-	-	-	-	-	-	-	-	-	-	426,169	8.34%	35,551	461,720
<b>Distribution Maintenance Total</b>		<b>167,385,477</b>	-	<b>(104,069,575)</b>	-	-	-	-	<b>(17,817)</b>	<b>(44,187,716)</b>	-	-	-	-	-	-	<b>19,110,370</b>		<b>1,594,174</b>	<b>20,704,543</b>
<b>Customer Accounts Operations</b>																				
CA		670,321	-	(332,677)	-	-	-	-	-	-	-	-	-	-	-	-	337,643	10.14%	34,225	371,869
CN		42,041,620	-	(27,152,867)	-	-	-	-	-	(840)	-	-	-	-	-	-	14,887,913	10.14%	1,509,111	16,397,024
ID		2,980,413	-	(1,830,517)	-	-	-	-	-	-	-	-	-	-	-	-	1,149,895	10.14%	116,559	1,266,454
OR		8,993,775	(14,359)	(1,711,100)	-	-	-	-	-	-	-	-	-	-	-	-	7,268,316	10.14%	736,751	8,005,067
UT		10,517,710	-	(5,497,774)	-	-	-	-	-	-	-	-	-	-	-	-	5,019,936	10.14%	508,845	5,528,780
WA		3,171,306	-	(974,198)	-	-	-	-	-	-	-	-	-	-	-	-	2,197,108	10.14%	222,709	2,419,817
WYP		1,545,826	-	(1,037,303)	-	-	-	-	-	-	-	-	-	-	-	-	508,523	10.14%	51,546	560,069
WYU		259,768	-	(196,588)	-	-	-	-	-	-	-	-	-	-	-	-	63,180	10.14%	6,404	69,584
<b>Customer Accounts Operations Total</b>		<b>70,180,739</b>	<b>(14,359)</b>	<b>(38,733,025)</b>	-	-	-	-	<b>(840)</b>	-	-	-	-	-	-	-	<b>31,432,514</b>		<b>3,186,151</b>	<b>34,618,665</b>
<b>Customer Service Operations</b>																				
CA		130,550	19,017	(27)	-	-	-	-	-	-	-	-	-	-	-	-	149,540	9.30%	13,911	163,451
CN		4,707,282	(73,991)	(3,609,350)	-	-	-	-	(1,119)	-	-	-	-	-	-	-	1,022,821	9.30%	95,150	1,117,972
ID		125,838	1,052	(14,124)	-	-	-	-	-	-	-	-	-	-	-	-	112,766	9.30%	10,490	123,256
OR		4,151,715	45,719	(2,133,756)	-	-	-	-	-	(3,058)	-	-	-	-	-	-	2,060,619	9.30%	191,694	2,252,313
OTHER		101,549,342	-	(33,413)	-	-	-	-	-	-	-	-	-	-	-	-	101,515,929	9.30%	9,443,746	110,959,675
UT		3,613,822	11,080	(2,846,724)	-	-	-	-	-	-	-	-	-	-	-	-	778,178	9.30%	72,392	850,570
WA		459,332	10,746	(319,510)	-	-	-	-	-	-	-	-	-	-	-	-	150,568	9.30%	14,007	164,575
WYP		1,291,527	-	(957,109)	-	-	-	-	-	-	-	-	-	-	-	-	334,418	9.30%	31,110	365,528
WYU		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.30%	-	0
<b>Customer Service Operations Total</b>		<b>116,029,408</b>	<b>13,622</b>	<b>(9,914,013)</b>	-	-	-	-	<b>(4,178)</b>	-	-	-	-	-	-	-	<b>106,124,839</b>		<b>9,872,500</b>	<b>115,997,340</b>
<b>A&amp;G Operations &amp; Maintenance</b>																				
920		78,753,241	-	(78,619,930)	-	-	-	-	-	-	-	-	-	-	-	-	133,311	6.28%	8,368	141,679
921		10,663,458	1,284,000	(3,300,981)	-	-	-	-	(9,661)	-	-	-	-	-	-	-	8,636,816	7.35%	635,107	9,271,923
922		(37,446,530)	-	27,772,793	-	-	-	-	-	-	-	-	-	-	-	-	(9,673,738)	6.28%	(607,195)	(10,280,933)
923		23,788,045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23,768,045	4.42%	1,050,382	24,818,427
924		16,037,127	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16,037,127	0.00%	-	16,037,127
925		153,085,341	-	-	(140,829,653)	-	-	-	-	-	-	-	-	-	-	-	12,255,688	0.00%	-	12,255,688
926		(1,047,501)	-	-	-	-	-	-	-	-	-	-	-	2,967,013	-	-	1,919,513	6.33%	121,534	2,041,046
928		24,669,376	-	(1,749,228)	-	-	-	-	-	-	-	-	-	-	-	-	22,920,147	7.90%	1,811,517	24,731,664
929		(3,457,972)	317	3,391,347	-	-	-	-	-	-	-	-	-	(431,525)	-	-	(497,833)	6.28%	(31,248)	(529,081)
930		2,268,077	-	-	-	-	-	-	(537,249)	-	-	-	-	-	-	-	1,730,828	5.08%	87,911	1,818,738
931		3,092,716	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,092,716	7.93%	245,224	3,337,941
935		26,538,982	-	(2,088,894)	-	-	-	-	-	-	-	-	-	-	-	-	24,450,088	5.03%	1,230,333	25,680,420
<b>A&amp;G Operations &amp; Maintenance Total</b>		<b>296,924,361</b>	<b>1,284,317</b>	<b>(54,584,894)</b>	<b>(33,000,000)</b>	<b>(140,829,653)</b>	<b>(140,829,653)</b>	<b>3,732,596</b>	<b>(537,249)</b>	<b>(9,661)</b>	<b>(46,361,732)</b>	<b>(33,207,191)</b>	<b>(1,572,584)</b>	<b>(32,412,400)</b>	<b>(14,648,254)</b>	<b>(431,525)</b>	<b>2,967,013</b>	<b>104,772,709</b>	<b>4,551,932</b>	<b>109,324,641</b>
<b>Grand Total</b>		<b>3,092,164,237</b>	<b>1,281,071</b>	<b>(469,869,081)</b>	<b>(33,000,000)</b>	<b>(140,829,653)</b>	<b>(140,829,653)</b>	<b>3,732,596</b>	<b>(537,249)</b>	<b>(61,751)</b>	<b>(46,361,732)</b>	<b>(33,207,191)</b>	<b>(1,572,584)</b>	<b>(32,412,400)</b>	<b>(14,648,254)</b>	<b>2,324,678,009</b>	<b>40,878,111</b>	<b>2,365,556,120</b>		

Ref 4.10.4

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Escalation Factors**

PAGE 4.10.7

*Note: Please see Confidential Exhibit PAC/1005 for details of escalation factors.*

	<b>Escalation Factors</b>	
	<b>June 2021 to December 2023</b>	<b>FERC Accounts</b>
<b>STEAM PRODUCTION PLANT</b>		
Operation:	8.20%	500 - 507
Maintenance:	7.00%	510 - 514
<b>HYDRO PRODUCTION PLANT</b>		
Operation:	9.48%	535 - 540
Maintenance:	7.32%	541 - 545
<b>OTHER PRODUCTION PLANT</b>		
Operation:	8.72%	546 - 550; 556 - 557
Maintenance:	7.00%	551 - 554
<b>TRANSMISSION PLANT</b>		
Operation:	4.62%	560 - 567
Maintenance:	8.36%	568 - 573
<b>DISTRIBUTION PLANT</b>		
Operation:	7.51%	580 - 589
Maintenance:	8.34%	590 - 598
<b>CUSTOMER ACCOUNTS</b>		
Operation:	10.14%	901 - 905
<b>CUSTOMER SERVICE and INFORMATION</b>		
Operation:	9.30%	907 - 910
<b>SALES</b>		
Operation:	10.50%	911 - 916
<b>ADMINISTRATIVE and GENERAL</b>		
Operation:	6.28%	920, 922, 929
Operation:	7.35%	921
Operation:	4.42%	923
Operation:	6.33%	926
Operation:	11.69%	927
Operation:	7.90%	928
Operation:	5.08%	930
Operation:	7.93%	931
Maintenance:	5.03%	935



PacifiCorp  
Oregon General Rate Case - December 2023  
Vegetation & Wildfire Management O&M

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
<i><u>Remove Base Period Expenses</u></i>							
System	593	1	(1,546,887)	SNPD	26.473%	(409,501)	4.11.1
Distribution	593	1	(42,640,829)	OR	Situs	(42,640,829)	4.11.1
Transmission	571	1	(2,174,016)	SG	26.070%	(566,773)	4.11.1
			<u>(46,361,732)</u>			<u>(43,617,103)</u>	
<i><u>Add Test Period Expenses</u></i>							
System	593	3	2,475,000	SNPD	26.473%	655,197	4.11.1
Distribution	593	3	68,453,082	OR	Situs	68,453,082	4.11.1
Transmission	571	3	3,312,955	SG	26.070%	863,699	4.11.1
			<u>74,241,037</u>			<u>69,971,978</u>	

**Description of Adjustment:**

This adjustments resets Vegetation and Wildfire Management expenses from levels included in the base period data to expected levels into the test period 12 months ending Dec 2023.

PacifiCorp  
Oregon General Rate Case - December 2023  
Vegetation and Wildfire Management Expenses

Description	Function	FERC	Base Period	Test Period
			12 ME June 2021	12 ME Dec 2023
Vegetation Management - Admin	System	593SNPD	1,546,887	2,475,000
Non-WMP Vegetation Management	Distribution	593OR	40,661,656	48,956,097
Non-WMP Vegetation Management	Transmission	571SG	2,124,890	2,688,319
WMP Vegetation Management	Distribution	593OR	1,225,311	15,289,309
WMP Vegetation Management	Transmission	571SG	41,256	476,636
WMP Non-Veg Management	Distribution	593OR	753,862	4,207,676
WMP Non-Veg Management	Transmission	571SG	7,870	148,000
			<b>46,361,732</b>	<b>74,241,037</b>

**Summary By Function:**

System	593SNPD	1,546,887	2,475,000	4.11
Distribution	593OR	42,640,829	68,453,082	4.11
Transmission	571SG	2,174,016	3,312,955	4.11
		<b>46,361,732</b>	<b>74,241,037</b>	

Description	Function	FERC	Oregon Allocated	
			Base Period	Test Period
			12 ME June 2021	12 ME Dec 2023
Vegetation Management - Admin	System	593SNPD	409,501	655,197
Non-WMP Vegetation Management	Distribution	593OR	40,661,656	48,956,097
Non-WMP Vegetation Management	Transmission	571SG	553,966	700,854
WMP Vegetation Management	Distribution	593OR	1,225,311	15,289,309
WMP Vegetation Management	Transmission	571SG	10,756	124,261
WMP Non-Veg Management	Distribution	593OR	753,862	4,207,676
WMP Non-Veg Management	Transmission	571SG	2,052	38,584
			<b>43,617,103</b>	<b>69,971,978</b>

**Oregon-Allocated Expenses By Function:**

System	593SNPD	409,501	655,197	4.11
Distribution	593OR	42,640,829	68,453,082	4.11
Transmission	571SG	566,773	863,699	4.11
		<b>43,617,103</b>	<b>69,971,978</b>	

**PacifiCorp  
Oregon General Rate Case - December 2023  
Transmission Wheeling - Facebook**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Transmission of Electricity by Others	566	3	(4,743,194)	SG	26.070%	(1,236,567)	

**Description of Adjustment:**

The Company executed a renewable resource contract in Utah (Docket 16-035-27) dedicated to serve load associated with Facebook. As a result of the increased load from this dedicated resource to serve Facebook, PacifiCorp will be allocated a higher ratio of wholesale transmission costs relative to other wholesale users of the Company's transmission system. This adjustment reallocates the resulting wheeling expense from other jurisdictions which would have otherwise been situs assigned to Utah.

*Note: Please see Confidential Exhibit PAC/1006 for redacted information.*

**Adjustment Detail:**

Facebook Load @ Input	[REDACTED]
Utah Line Loss	5.09%
Estimated Facebook Load @ Sales	[REDACTED]
Average On-Peak and Off-Peak OATT Rate	[REDACTED]
Total Transmission Wheeling for Reallocation	4,743,194 Ref. 4.12.1

## Tab 5 - Net Power Cost

**PacifiCorp**  
**Oregon General Rate Case – December 2023**  
**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 2021 provide the starting point for establishing the adjustment amounts for the December 2023 test period.

- 5.1 Net Power Costs
- 5.2 BOSR & WRAP Fees

**Pacificorp**  
**Oregon General Rate Case - December 2023**  
**Tab 5 Adjustment Summary**

	5.1	5.2	
	Total Adjustments	Net Power Costs	BOSR & WRAP Fees
1 Operating Revenues:			
2 General Business Revenues	-	-	-
3 Interdepartmental	-	-	-
4 Special Sales	40,563,155	40,563,155	-
5 Other Operating Revenues	-	-	-
6 Total Operating Revenues	<u>40,563,155</u>	<u>40,563,155</u>	<u>-</u>
7			
8 Operating Expenses:			
9 Steam Production	(14,027,757)	(14,027,757)	-
10 Nuclear Production	-	-	-
11 Hydro Production	-	-	-
12 Other Power Supply	74,475,770	74,191,604	284,167
13 Transmission	3,021,006	3,021,006	-
14 Distribution	-	-	-
15 Customer Accounting	-	-	-
16 Customer Service & Info	-	-	-
17 Sales	-	-	-
18 Administrative & General	-	-	-
19			
20 Total O&M Expenses	<u>63,469,020</u>	<u>63,184,853</u>	<u>284,167</u>
21			
22 Depreciation	-	-	-
23 Amortization	-	-	-
24 Taxes Other Than Income	-	-	-
25 Income Taxes - Federal	(4,594,138)	(4,537,164)	(56,974)
26 Income Taxes - State	(1,040,445)	(1,027,542)	(12,903)
27 Income Taxes - Def Net	-	-	-
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	-
30			
31 Total Operating Expenses:	<u>57,834,436</u>	<u>57,620,147</u>	<u>214,289</u>
32			
33 Operating Rev For Return:	<u>(17,271,281)</u>	<u>(17,056,991)</u>	<u>(214,289)</u>
34			
35 Rate Base:			
36 Electric Plant In Service	-	-	-
37 Plant Held for Future Use	-	-	-
38 Misc Deferred Debits	-	-	-
39 Elec Plant Acq Adj	-	-	-
40 Nuclear Fuel	-	-	-
41 Prepayments	-	-	-
42 Fuel Stock	-	-	-
43 Material & Supplies	-	-	-
44 Working Capital	546,651	544,626	2,025
45 Weatherization Loans	-	-	-
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	<u>546,651</u>	<u>544,626</u>	<u>2,025</u>
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	-	-	-
52 Accum Prov For Amort	-	-	-
53 Accum Def Income Tax	-	-	-
54 Unamortized ITC	-	-	-
55 Customer Adv For Const	-	-	-
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	-	-	-
58			
59 Total Rate Base Deductions	<u>-</u>	<u>-</u>	<u>-</u>
60			
61 Total Rate Base:	<u>546,651</u>	<u>544,626</u>	<u>2,025</u>
62			
63 Return on Rate Base	-0.360%	-0.355%	-0.004%
64			
65 Return on Equity	-0.688%	-0.680%	-0.009%
66			
67 TAX CALCULATION:			
68 Operating Revenue	(22,905,864)	(22,621,698)	(284,167)
69 Other Deductions	-	-	-
70 Interest (AFUDC)	-	-	-
71 Interest	11,431	11,388	42
72 Schedule "M" Additions	-	-	-
73 Schedule "M" Deductions	-	-	-
74 Income Before Tax	<u>(22,917,295)</u>	<u>(22,633,086)</u>	<u>(284,209)</u>
75			
76 State Income Taxes	<u>(1,040,445)</u>	<u>(1,027,542)</u>	<u>(12,903)</u>
77 Taxable Income	<u>(21,876,850)</u>	<u>(21,605,544)</u>	<u>(271,306)</u>
78			
79 Federal Income Taxes + Other	<u>(4,594,138)</u>	<u>(4,537,164)</u>	<u>(56,974)</u>
APPROXIMATE PRICE CHANGE	23,732,287	23,438,304	293,982

PacifiCorp  
Oregon General Rate Case - December 2023  
Net Power Costs

PAGE 5.1

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
<b>Adjustment to Revenue:</b>							
<b>Sales for Resale (Account 447)</b>							
Existing Firm PPL	447NPC	3	6,189,133	SG	26.070%	1,613,528	5.1.1
Existing Firm UPL	447NPC	3	-	SG	26.070%	-	5.1.1
Post-Merger Firm	447NPC	3	145,837,137	SG	26.070%	38,020,240	5.1.1
Non-Firm	447NPC	3	3,707,443	SE	25.068%	929,387	5.1.1
<b>Total Sales for Resale</b>			<u>155,733,713</u>			<u>40,563,155</u>	
<b>Adjustment to Expense:</b>							
<b>Purchased Power (Account 555)</b>							
Existing Firm Demand PPL	555NPC	3	8,295,068	SG	26.070%	2,162,553	5.1.1
Existing Firm Demand UPL	555NPC	3	11,456,377	SG	26.070%	2,986,717	5.1.1
Existing Firm Energy	555NPC	3	44,724,911	SE	25.068%	11,211,701	5.1.1
Post-merger Firm	555NPC	3	298,036,729	SG	26.070%	77,699,195	5.1.1
Post-merger Firm - Situs	555NPC	3	(10,277,762)	UT	Situs	-	5.1.1
Secondary Purchases	555NPC	3	(62,781,784)	SE	25.068%	(15,738,222)	5.1.1
Seasonal Contracts	555NPC	3		SG	26.070%	-	5.1.1
Other Generation	555NPC	3		SG	26.070%	-	5.1.1
<b>Total Purchased Power Adjustments:</b>			<u>289,453,539</u>			<u>78,321,943</u>	
<b>Wheeling Expense (Account 565)</b>							
Existing Firm PPL	565NPC	3	23,886,724	SG	26.070%	6,227,351	5.1.1
Existing Firm UPL	565NPC	3	-	SG	26.070%	-	5.1.1
Post-merger Firm	565NPC	3	(8,853,324)	SG	26.070%	(2,308,092)	5.1.1
Non-Firm	565NPC	3	(3,583,246)	SE	25.068%	(898,253)	5.1.1
<b>Total Wheeling Expense Adjustments:</b>			<u>11,450,154</u>			<u>3,021,006</u>	
<b>Fuel Expense (Accounts 501, 503, 547)</b>							
Fuel - Overburden Amortization - Idaho	501NPC	3	(35,987)	ID	Situs	-	5.1.1
Fuel - Overburden Amortization - Wyoming	501NPC	3	(101,258)	WYP	Situs	-	5.1.1
Fuel Consumed - Coal	501NPC	3	(19,138,275)	SE	25.068%	(4,797,609)	5.1.1
Fuel Consumed - Gas	501NPC	3	(5,143,679)	SE	25.068%	(1,289,424)	5.1.1
Steam from Other Sources	503NPC	3	(635,805)	SE	25.068%	(159,385)	5.1.1
Natural Gas Consumed	547NPC	3	12,287,901	SE	25.068%	3,080,348	5.1.1
Simple Cycle Combustion Turbines	547NPC	3	7,486,648	SE	25.068%	1,876,763	5.1.1
Cholla / APS Exchange	501NPC	3	(31,040,758)	SE	25.068%	(7,781,339)	5.1.1
<b>Total Fuel Expense Adjustments:</b>			<u>(36,321,213)</u>			<u>(9,070,646)</u>	
<b>Total Power Cost Adjustment</b>			<u>108,848,767</u>			<u>31,709,147</u>	
Post-merger Firm Type 1	555NPC	1	(33,207,191)	SG	26.070%	(8,657,228)	5.1.1
Oregon Solar Project	555NPC	3	(430,221)	OR	Situs	(430,221)	5.1.4

**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 2023. The Aurora study for this adjustment is based on forecast loads for the test period.

As described in the testimony of Sherona L. Cheung, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; the Company is not requesting recovery of NPC as part of the general rate case.



PacifiCorp  
Oregon General Rate Case - December 2023  
Net Power Cost Adjustment

Description	FERC Account	(1) Total Account (B Tabs)	(2) Remove Non-NPC / NPC Mechanism Accruals	(3) Unadjusted NPC (1) + (2)	(4) Type 1 Adjustments	(5) Type 1 Normalized NPC (3) + (4)	(6) Type 3 Pro Forma NPC	(7) Type 3 Adjustment (6) - (5)	Factor
<b>Sales for Resale (Account 447)</b>									
Existing Firm Sales PPL	447.12	-	-	-	-	-	6,189,133	6,189,133	SG
Existing Firm Sales UPL	447.122	-	-	-	-	-	-	-	SG
Post-merger Firm Sales	447.13, .14, .20, .61, .62	203,582,709.68	-	203,582,710	-	203,582,710	349,419,847	145,837,137	SG
Non-firm Sales	447.5	(3,707,443)	-	(3,707,443)	-	(3,707,443)	-	3,707,443	SE
Transmission Services	447.9	124,586	(124,586)	-	-	-	-	-	S
On-system Wholesale Sales	447.1	12,315,816	(12,315,816)	-	-	-	-	-	S
<b>Total Revenue Adjustments</b>		<b>212,315,668</b>	<b>(12,440,401)</b>	<b>199,875,267</b>	<b>-</b>	<b>199,875,267</b>	<b>355,608,980</b>	<b>155,733,713</b>	
<b>Purchased Power (Account 555)</b>									
Existing Firm Demand PPL	555.66	-	-	-	-	-	8,295,068	8,295,068	SG
Existing Firm Demand UPL	555.68	-	-	-	-	-	11,456,377	11,456,377	SG
Existing Firm Energy	555.65, 555.69	-	-	-	-	-	44,724,911	44,724,911	SE
Post-merger Firm	555.26, .55, .59, .61, .62, .63, .64, .67, .8	621,018,560	-	621,018,560	-	621,018,560	885,848,099	264,829,538	SG
Post-merger Firm - Situs	555.27	10,277,762	-	10,277,762	-	10,277,762	-	(10,277,762)	UT
Secondary Purchases	555.7, 555.25	62,781,784	-	62,781,784	-	62,781,784	-	(62,781,784)	SE
NPC Deferral Mechanism	555.57	(171,224)	171,224	-	-	-	-	-	OTHER
Seasonal Contracts	-	-	-	-	-	-	-	-	SG
Wind Integration Charge	-	-	-	-	-	-	-	-	SG
RPS Compliance Purchases	555.22, 555.23, 555.24	4,161,734	(4,161,734)	-	-	-	-	-	OTHER
BPA Regional Adjustments	555.11, 555.12, 555.133	-	-	-	-	-	-	-	S
Post-merger Firm Type 1	-	-	-	-	(33,207,191)	(33,207,191)	-	33,207,191	SG
<b>Total Purchased Power Adjustment</b>		<b>698,068,616</b>	<b>(3,990,510)</b>	<b>694,078,107</b>	<b>(33,207,191)</b>	<b>660,870,916</b>	<b>950,324,455</b>	<b>289,453,539</b>	
<b>Wheeling (Account 565)</b>									
Existing Firm PPL	565.26	-	-	-	-	-	23,886,724	23,886,724	SG
Existing Firm UPL	565.27	-	-	-	-	-	-	-	SG
Post-merger Firm	565.0, 565.46, 565.1	133,395,046	-	133,395,046	-	133,395,046	124,541,723	(8,853,324)	SG
Non-firm	565.25	15,971,607	-	15,971,607	-	15,971,607	12,388,361	(3,583,246)	SE
<b>Total Wheeling Expense Adjustment</b>		<b>149,366,653</b>	<b>-</b>	<b>149,366,653</b>	<b>-</b>	<b>149,366,653</b>	<b>160,816,807</b>	<b>11,450,154</b>	
<b>Fuel Expense (Accounts 501, 503 and 547)</b>									
Fuel - Overburden Amortization - Idaho	501.12	35,987	-	35,987	-	35,987	-	(35,987)	ID
Fuel - Overburden Amortization - Wyoming	501.12	101,258	-	101,258	-	101,258	-	(101,258)	WY
Fuel Consumed - Coal	501.1	619,107,412	-	619,107,412	-	619,107,412	599,969,137	(19,138,275)	SE
Fuel Consumed - Gas	501.35	18,260,998	-	18,260,998	-	18,260,998	13,117,319	(5,143,679)	SE
Steam From Other Sources	503	5,119,912	-	5,119,912	-	5,119,912	4,484,106	(635,805)	SE
Natural Gas Consumed	547.1	289,072,443	-	289,072,443	-	289,072,443	301,360,345	12,287,901	SE
Simple Cycle Combustion Turbines	547.1	1,980,087	-	1,980,087	-	1,980,087	9,466,735	7,486,648	SE
Cholla/APS Exchange	501.1	31,040,758	-	31,040,758	-	31,040,758	-	(31,040,758)	SE
Fuel Regulatory Costs Deferral and Amort	501.15	6,207,125	(6,207,125)	-	-	-	-	-	S
Fuel Regulatory Costs Deferral and Amort	501.15	3,129,281	(3,129,281)	-	-	-	-	-	SE
Miscellaneous Fuel Costs	501.0, .2, .3, .4, .45, .5, .51	13,625,871	(13,625,871)	-	-	-	-	-	SE
Miscellaneous Fuel Costs - Cholla	501.2, 501.45	264,509	(264,509)	-	-	-	-	-	SE
<b>Total Fuel Expense</b>		<b>987,945,641</b>	<b>(23,226,786)</b>	<b>964,718,855</b>	<b>-</b>	<b>964,718,855</b>	<b>928,397,642</b>	<b>(36,321,213)</b>	
<b>Net Power Cost</b>		<b>1,623,065,242</b>	<b>(14,776,894)</b>	<b>1,608,288,348</b>	<b>(33,207,191)</b>	<b>1,575,081,157</b>	<b>1,683,929,924</b>	<b>108,848,767</b>	
					Ref 5.1		Ref 5.1.3	Ref 5.1	

Exhibit PAC/1002  
Cheung/125

**PacifiCorp  
Oregon General Rate Case - December 2023  
Net Power Cost Study**

**Study Results  
MERGED PEAK/ENERGY SPLIT  
(\$)**

	Merged 1/2023 - 12/2023	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
<b>SPECIAL SALES FOR RESALE</b>					
Pacific Pre Merger	6,189,133	6,189,133			
Post Merger	349,419,847				349,419,847
Utah Pre Merger	-	-			
NonFirm Sub Total	-			-	
<b>TOTAL SPECIAL SALES</b>	<b>355,608,980</b>	<b>6,189,133</b>	<b>-</b>	<b>-</b>	<b>349,419,847</b>
<b>PURCHASED POWER &amp; NET INTERCHANGE</b>					
BPA Peak Purchase	-	-			
Pacific Capacity	-	-			
Mid Columbia	2,265,569	679,671	1,585,898		
Misc/Pacific	154,785	32,097	122,688		
Q.F. Contracts/PPL	-	7,583,300	36,946,945		102,499,061
Small Purchases west	-	-			
<b>Pacific Sub Total</b>	<b>2,420,354</b>	<b>8,295,068</b>	<b>38,655,531</b>	<b>-</b>	<b>102,499,061</b>
Gemstate	1,145,216		1,145,216		
GSLM	-				
QF Contracts/UPL	-	11,456,377	4,909,876		163,582,622
IPP Layoff	-	-			
Small Purchases east	14,288		14,288		
UP&L to PP&L	-	-			
<b>Utah Sub Total</b>	<b>1,159,504</b>	<b>11,456,377</b>	<b>6,069,380</b>	<b>-</b>	<b>163,582,622</b>
APS Supplemental	-				-
Avoided Cost Resource	-				-
Appaloosa 1A Solar	1,565,395				1,565,395
Appaloosa 1B Solar	1,043,597				1,043,597
Castle Solar UoU	-				-
Castle Solar IHC	-				-
Cedar Springs Wind	11,723,272				11,723,272
Cedar Springs Wind III	8,908,094				8,908,094
Combine Hills Wind	5,518,680				5,518,680
Cove Mountain Solar	3,833,283				3,833,283
Cove Mountain Solar II	9,492,755				9,492,755
Deseret Purchase	35,399,601				35,399,601
Eagle Mountain - UAMPS/UMPA	-				-
Elektron Solar 20 yr	797,568				797,568
Elektron Solar 25yr	5,433,412				5,433,412
Horseshoe Solar	5,348,701				5,348,701
Hurricane Purchase	185,380				185,380
Hunter Solar	7,051,153				7,051,153
MagCorp	-				-
MagCorp Reserves	3,837,570				3,837,570
Milican Solar	2,814,730				2,814,730
Milford Solar	6,975,304				6,975,304
Old Mill Solar	-				-
Monsanto Reserves	20,600,000				20,600,000
Pavant III Solar	-				-
Prineville Solar	1,875,216				1,875,216
Rock River Wind	-				-
Rocket Solar	5,701,664				5,701,664
Skysol Solar	9,192,400				9,192,400
Soda Lake Geothermal	-				-
Top of the World Wind	40,663,534				40,663,534
Tri-State Purchase	-				-
Wolverine Creek Wind	10,515,791				10,515,791
PSCo Exchange	-				-
West Valley Toll	-				-
UT Solar Adjustment	(15,944,747)				(15,944,747)

	Merged <u>1/2023 - 12/2023</u>	Pre-Merger <u>Demand</u>	Pre-Merger <u>Energy</u>	<u>Non-Firm</u>	<u>Post-Merger</u>
<b>SPECIAL SALES FOR RESALE</b>					
Pacific Pre Merger	6,189,133	6,189,133			
Seasonal Purchased Power Constellation 2013-2016	-				-
Short Term Firm Purchases	397,201,954				397,201,954
-----		-----	-----	-----	-----
New Firm Sub Total	619,766,416	-	-	-	619,766,416
Integration Charge	-				-
Non Firm Sub Total	-			-	-
-----		-----	-----	-----	-----
TOTAL PURCHASED PW & NET INT.	623,346,275	19,751,445	44,724,911	-	885,848,099
<b>WHEELING &amp; U. OF F. EXPENSE</b>					
Pacific Firm Wheeling and Use of Facilities	23,886,724	23,886,724			
Utah Firm Wheeling and Use of Facilities	-	-			
Post Merger	124,541,723				124,541,723
Nonfirm Wheeling	12,388,361			12,388,361	
-----		-----	-----	-----	-----
TOTAL WHEELING & U. OF F. EXPENSE	160,816,807	23,886,724	-	12,388,361	124,541,723
<b>THERMAL FUEL BURN EXPENSE</b>					
Carbon	-				-
Cholla	-				-
Colstrip	18,388,036			18,388,036	
Craig	14,393,703			14,393,703	
Chehalis	60,877,049			60,877,049	
Currant Creek	55,731,824			55,731,824	
Dave Johnston	63,751,340			63,751,340	
Gadsby	13,117,319			13,117,319	
Gadsby CT	9,466,735			9,466,735	
Hayden	10,169,525			10,169,525	
Hermiston	28,824,508			28,824,508	
Hunter	126,226,934			126,226,934	
Huntington	110,658,947			110,658,947	
Jim Bridger	196,125,182			196,125,182	
Lake Side 1	68,555,547			68,555,547	
Lake Side 2	50,258,935			50,258,935	
Naughton - Gas	20,696,079			20,696,079	
Naughton	27,974,534			27,974,534	
Wyodak	32,280,937			32,280,937	
Gas Physical	(6,259,946)			(6,259,946)	
Gas Swaps	(17,010,410)			(17,010,410)	
Clay Basin Gas Storage	(452,163)			(452,163)	
Pipeline Reservation Fees	40,138,923			40,138,923	
-----		-----	-----	-----	-----
TOTAL FUEL BURN EXPENSE	923,913,535	-	-	923,913,535	-
<b>OTHER GENERATION EXPENSE</b>					
Blundell	4,484,106			4,484,106	
-----		-----	-----	-----	-----
TOTAL OTHER GEN. EXPENSE	4,484,106	-	-	4,484,106	-
=====		=====	=====	=====	=====
NET POWER COST	<b>1,683,929,924</b>	37,449,035	44,724,911	940,786,003	660,969,975
=====		=====	=====	=====	=====

Ref 5.1.1

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Net Power Cost Adjustment**  
**Oregon Situs Adjustments**

	<b>Total</b>	<b>Jan-23</b>	<b>Feb-23</b>	<b>Mar-23</b>	<b>Apr-23</b>	<b>May-23</b>	<b>Jun-23</b>	<b>Jul-23</b>	<b>Aug-23</b>	<b>Sep-23</b>	<b>Oct-23</b>	<b>Nov-23</b>	<b>Dec-23</b>
Net Energy impact - Situs Solar	<b>17,320</b>	(4,003)	219	12,573	44,877	61,801	72,310	(62,349)	(89,397)	(41,864)	16,543	6,748	(139)
REP Adjustments (Total Company)	<b>(1,794,801)</b>	(96,427)	(94,986)	(106,988)	(123,482)	(200,250)	(252,202)	(184,018)	(143,309)	(127,841)	(161,091)	(137,569)	(166,637)
Allocated on SG Factor (26.070%)	<b>(467,911)</b>	(25,139)	(24,763)	(27,892)	(32,192)	(52,206)	(65,750)	(47,974)	(37,361)	(33,329)	(41,997)	(35,865)	(43,443)
REP Adjustments (Oregon Allocation)	<b>20,370</b>	(271)	268	1,915	2,914	4,898	4,018	(3,595)	(6,015)	(2,756)	87	332	18,577
<b>Total OR Situs Adjustment</b>	<b>(430,221)</b>	(29,413)	(24,276)	(13,404)	15,599	14,493	10,578	(113,918)	(132,774)	(77,949)	(25,367)	(28,785)	(25,005)

**PacifiCorp  
Oregon General Rate Case - December 2023  
BSOR & WRAP Fees**

<b>Adjustment to Expense:</b>	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
BOSR Fee	557	3	90,000	SG	26.070%	23,463	5.2.1
WRAP Fee	557	3	1,000,000	SG	26.070%	260,703	5.2.1

**Description of Adjustment:**

This adjustment adds the two new fees to O&M costs. The first one is for EIM Board of State Regulators (BOSR). The primary function of the Body of State Regulators is to provide a forum for state regulators to learn about the Western Energy Imbalance Market (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 NWPP region, through the development and implementation of a Western Resource Adequacy Program (WRAP). For further discussion on these fees, please refer to direct testimony of Mr. Michael G. Wilding.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**BOSR & WRAP Fees**

<b>Incremental O&amp;M</b>	<b>CY 2023</b>	
	<b>Amount</b>	
EIM Board of State Regulators	\$ 90,000	
Western Resource Adequacy Program	\$ 1,000,000	
	<b>\$ 1,090,000</b>	<b>Ref 5.2</b>

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**PacifiCorp**  
**Oregon General Rate Case – December 2023**  
**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 & Amortization Expense
- 6.2 Depreciation & Amortization Reserve
- 6.3 Depreciation Allocation Correction
- 6.4 Repowering Buy Downs
- 6.5 Coal Depreciable Life Update
- 6.6 Bridger Coal Reclamation Costs





**PacifiCorp  
Oregon General Rate Case - December 2023  
Depreciation & Amortization Expense  
Adjustment to Test Period Levels**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Steam Depreciation Expense	403SP	3	26,840,673	SG	26.070%	6,997,455	
Steam Depreciation Expense	403SP	3	19,020,532	SG	26.070%	4,958,718	
Steam Depreciation Expense	403SP	3	118,268,095	SG	26.070%	30,832,897	
Steam Depreciation Expense	403SP	3	(7,589,695)	SG	26.070%	(1,978,660)	
Hydro Depreciation Expense	403HP	3	28,228,285	SG-P	26.070%	7,359,210	
Hydro Depreciation Expense	403HP	3	(99,213)	SG-U	26.070%	(25,865)	
Hydro Depreciation Expense	403HP	3	(25,970,964)	SG-P	26.070%	(6,770,719)	
Hydro Depreciation Expense	403HP	3	1,945,365	SG-U	26.070%	507,163	
Other Depreciation Expense	403OP	3	-	SG	26.070%	-	
Other Depreciation Expense	403OP	3	2,570,714	SG	26.070%	670,194	
Other Depreciation Expense	403OP	3	39,134,400	SG-W	26.070%	10,202,472	
Other Depreciation Expense	403OP	3	-	OR	Situs	-	
Other Depreciation Expense	403OP	3	624,964	SG	26.070%	162,930	
Transmission Depreciation Expense	403TP	3	(353,434)	SG	26.070%	(92,141)	
Transmission Depreciation Expense	403TP	3	(318,735)	SG	26.070%	(83,095)	
Transmission Depreciation Expense	403TP	3	13,515,484	SG	26.070%	3,523,533	
Distribution Depreciation Expense	403360	3	243,644	OR	Situs	7,873	
Distribution Depreciation Expense	403361	3	461,852	OR	Situs	14,924	
Distribution Depreciation Expense	403362	3	3,832,165	OR	Situs	123,826	
Distribution Depreciation Expense	403364	3	5,008,218	OR	Situs	161,827	
Distribution Depreciation Expense	403365	3	3,151,495	OR	Situs	101,832	
Distribution Depreciation Expense	403366	3	1,563,558	OR	Situs	50,522	
Distribution Depreciation Expense	403367	3	3,647,465	OR	Situs	117,858	
Distribution Depreciation Expense	403368	3	5,521,053	OR	Situs	178,398	
Distribution Depreciation Expense	403369	3	3,414,086	OR	Situs	110,317	
Distribution Depreciation Expense	403370	3	934,553	OR	Situs	30,198	
Distribution Depreciation Expense	403371	3	32,312	OR	Situs	1,044	
Distribution Depreciation Expense	403373	3	231,403	OR	Situs	7,477	
General Depreciation Expense	403GP	3	44,174	CA	Situs	-	
General Depreciation Expense	403GP	3	602,059	OR	Situs	602,059	
General Depreciation Expense	403GP	3	16,660	WA	Situs	-	
General Depreciation Expense	403GP	3	269,935	WYP	Situs	-	
General Depreciation Expense	403GP	3	987,962	UT	Situs	-	
General Depreciation Expense	403GP	3	103,649	ID	Situs	-	
General Depreciation Expense	403GP	3	(20,100)	WYU	Situs	-	
General Depreciation Expense	403GP	3	(2,389)	SG	26.070%	(623)	
General Depreciation Expense	403GP	3	(23,398)	SG	26.070%	(6,100)	
General Depreciation Expense	403GP	3	603,633	SG	26.070%	157,369	
General Depreciation Expense	403GP	3	6,592,574	SO	27.173%	1,791,406	
General Depreciation Expense	403GP	3	(66,807)	SG	26.070%	(17,417)	
General Depreciation Expense	403GP	3	701	SG	26.070%	183	
General Depreciation Expense	403GP	3	(43,613)	CN	30.990%	(13,516)	
General Depreciation Expense	403GP	3	2,511	SE	25.068%	629	
			<u>252,925,826</u>			<u>59,684,178</u>	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 8.4. The annualized 2022 depreciation and amortization expense for the test period is calculated by applying the current composite depreciation and amortization rates to the December 2022 projected plant balances.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Depreciation & Amortization Expense**  
**Adjustment to Test Period Levels**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Intangible Amortization	404IP	3	-	CA	Situs	-	
Intangible Amortization	404IP	3	264,103	CN	30.990%	81,845	
Intangible Amortization	404IP	3	(1,673)	SG	26.070%	(436)	
Intangible Amortization	404IP	3	(78,646)	SG	26.070%	(20,503)	
Intangible Amortization	404IP	3	(8)	ID	Situs	-	
Intangible Amortization	404IP	3	2	OR	Situs	2	
Intangible Amortization	404IP	3	(14,686)	SE	25.068%	(3,682)	
Intangible Amortization	404IP	3	(8,908,817)	SG	26.070%	(2,322,559)	
Intangible Amortization	404IP	3	(14,435)	SG-P	26.070%	(3,763)	
Intangible Amortization	404IP	3	21,234	SG-U	26.070%	5,536	
Intangible Amortization	404IP	3	(13,762)	SG	26.070%	(3,588)	
Intangible Amortization	404IP	3	14,942,879	SO	27.173%	4,060,441	
Intangible Amortization	404IP	3	974	UT	Situs	-	
Intangible Amortization	404IP	3	16	WA	Situs	-	
Intangible Amortization	404IP	3	(2,422)	WYP	Situs	-	
Intangible Amortization	404IP	3	-	WYU	Situs	-	
Hydro Amortization	404HP	3	-	SG	26.070%	-	
Hydro Amortization	404HP	3	0	SG-P	26.070%	0	
Hydro Amortization	404HP	3	-	SG-U	26.070%	-	
Other Amortization	404OP	3	-	SG	26.070%	-	
General Amortization	404GP	3	(20)	CA	Situs	-	
General Amortization	404GP	3	-	CN	30.990%	-	
General Amortization	404GP	3	29,179	OR	Situs	29,179	
General Amortization	404GP	3	(138,845)	SO	27.173%	(37,729)	
General Amortization	404GP	3	(832)	UT	Situs	-	
General Amortization	404GP	3	3,665	WA	Situs	-	
General Amortization	404GP	3	0	WYP	Situs	-	
General Amortization	404GP	3	-	WYU	Situs	-	
			<u>6,087,906</u>			<u>1,784,744</u>	6.1.5

**Description of Adjustment:**

This adjustment reflects the incremental depreciation expense that is calculated on the plant additions included in this filing in adjustment 8.4. The annualized 2022 depreciation and amortization expense for the test period is calculated by applying the current composite depreciation and amortization rates to the December 2022 projected plant balances.

**PacifiCorp  
Oregon General Rate Case - December 2023  
Depreciation and Amortization Expense Summary**

Description	Account	Factor	12 ME Jun 2021 Expense	Test Period Expense	Adjustment to Test Period
<b>DEPRECIATION EXPENSE</b>					
<b>Steam Production Plant:</b>					
Pre-merger Pacific	403SP	SG	40,420,413	67,261,085	26,840,673
Pre-merger Utah	403SP	SG	33,611,594	52,632,126	19,020,532
Post-merger	403SP	SG	223,954,796	342,222,891	118,268,095
Post-merger	403SP	SG	7,589,695	-	(7,589,695)
Total Steam Plant			305,576,498	462,116,102	156,539,604
<b>Hydro Production Plant:</b>					
Pre-merger Pacific	403HP	SG-P	(24,185,191)	4,043,093	28,228,285
Pre-merger Utah	403HP	SG-U	1,348,641	1,249,428	(99,213)
Post-merger	403HP	SG-P	47,425,286	21,454,323	(25,970,964)
Post-merger	403HP	SG-U	6,654,516	8,599,880	1,945,365
Total Hydro Plant			31,243,252	35,346,724	4,103,473
<b>Other Production Plant:</b>					
Pre-merger Utah	403OP	SG	-	-	-
Post-merger	403OP	SG	65,951,638	68,522,352	2,570,714
Post-merger Wind	403OP	SG-W	97,958,758	137,093,159	39,134,400
Post-merger Wind	403OP	OR	-	-	-
Post-merger	403OP	SG	3,697,797	4,322,762	624,964
Total Other Production Plant			167,608,194	209,938,272	42,330,078
<b>Transmission Plant:</b>					
Pre-merger Pacific	403TP	SG	8,458,141	8,104,707	(353,434)
Pre-merger Utah	403TP	SG	10,613,292	10,294,556	(318,735)
Post-merger	403TP	SG	106,315,401	119,830,885	13,515,484
Total Transmission Plant			125,386,834	138,230,148	12,843,315
<b>Distribution Plant:</b>					
California	403364	CA	7,856,350	9,254,102	1,397,752
Oregon	403364	OR	55,521,949	56,428,045	906,096
Washington	403364	WA	15,183,453	16,032,588	849,135
Eastern Wyoming	403364	WYP	18,117,193	19,227,174	1,109,981
Utah	403364	UT	72,275,031	93,266,338	20,991,307
Idaho	403364	ID	8,951,667	11,380,194	2,428,527
Western Wyoming	403364	WYU	3,785,512	4,144,520	359,008
Total Distribution Plant			181,691,155	209,732,961	28,041,805
<b>General Plant:</b>					
California	403GP	CA	429,862	474,036	44,174
Oregon	403GP	OR	5,548,245	6,150,304	602,059
Washington	403GP	WA	1,100,960	1,117,620	16,660
Eastern Wyoming	403GP	WYP	1,986,530	2,256,466	269,935
Utah	403GP	UT	5,162,843	6,150,804	987,962
Idaho	403GP	ID	988,458	1,092,107	103,649
Western Wyoming	403GP	WYU	404,794	384,695	(20,100)
Pre-merger Pacific	403GP	SG	18,231	15,841	(2,389)
Pre-merger Utah	403GP	SG	51,315	27,917	(23,398)
Post-merger	403GP	SG	10,111,049	10,714,682	603,633
General Office	403GP	SO	16,310,325	22,902,899	6,592,574
General Office	403GP	SG	66,807	-	(66,807)
General Office	403GP	SG	8,187	8,888	701
Customer Service	403GP	CN	966,692	923,079	(43,613)
Fuel Related	403GP	SE	108,300	110,810	2,511
Total General Plant			43,262,598	52,330,149	9,067,551
<b>Total Depreciation Expense</b>			<b>854,768,531</b>	<b>1,107,694,357</b>	<b>252,925,826</b>

Ref 6.1

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Depreciation and Amortization Expense Summary**

Description	Account	Factor	12 ME Jun 2021 Expense	Test Period Expense	Adjustment to Test Period
<b>AMORTIZATION EXPENSE</b>					
<b>Intangible Plant:</b>					
California	404IP	CA	1,765	1,765	-
Customer Service	404IP	CN	13,528,148	13,792,251	264,103
Pre-merger Utah	404IP	SG	14,143	12,470	(1,673)
Pre-merger Pacific	404IP	SG	78,646	-	(78,646)
Idaho	404IP	ID	23,042	23,033	(8)
Oregon	404IP	OR	11,685	11,687	2
Fuel Related	404IP	SE	1,821	(12,865)	(14,686)
Post-merger	404IP	SG	16,038,025	7,129,208	(8,908,817)
Hydro Relicensing	404IP	SG-P	2,694,702	2,680,267	(14,435)
Hydro Relicensing	404IP	SG-U	293,112	314,346	21,234
Post-merger	404IP	SG	13,762	-	(13,762)
General Office	404IP	SO	14,405,872	29,348,751	14,942,879
Utah	404IP	UT	37,828	38,802	974
Washington	404IP	WA	3,133	3,148	16
Eastern Wyoming	404IP	WYP	110,823	108,401	(2,422)
Western Wyoming	404IP	WYU	-	-	-
Total Intangible Plant			<u>47,256,507</u>	<u>53,451,266</u>	<u>6,194,759</u>
<b>Hydro Production Plant:</b>					
Pre-merger Pacific	404HP	SG	-	-	-
Post-merger	404HP	SG-P	311,696	311,696	0
Post-merger	404HP	SG-U	-	-	-
Total Hydro Plant			<u>311,696</u>	<u>311,696</u>	<u>0</u>
<b>Other Production Plant:</b>					
Post-merger	404OP	SG	-	-	-
Total Other Plant			<u>-</u>	<u>-</u>	<u>-</u>
<b>General Plant:</b>					
California	404GP	CA	20	-	(20)
General Office	404GP	CN	-	-	-
Oregon	404GP	OR	293,726	322,905	29,179
General Office	404GP	SO	247,138	108,292	(138,845)
Utah	404GP	UT	832	-	(832)
Washington	404GP	WA	92,604	96,268	3,665
Eastern Wyoming	404GP	WYP	53,169	53,169	0
Western Wyoming	404GP	WYU	-	-	-
Total General Plant			<u>687,488</u>	<u>580,634</u>	<u>(106,854)</u>
<b>Total Amortization</b>			<u>48,255,690</u>	<u>54,343,596</u>	<u>6,087,906</u>
					<b>Ref 6.1.1</b>
<b>Total Depreciation and Amortization</b>			<u>903,024,221</u>	<u>1,162,037,953</u>	<u>259,013,732</u>
				<b>Ref. 6.1.13</b>	

PacifiCorp  
Oregon General Rate Case - December 2023  
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjusted EPIS Balance			Depreciation Expense			Adjusted EPIS Balance			Depreciation Expense			Adjusted EPIS Balance			Depreciation Expense		
			Jun 2021	Jun 2021	Adjustments	Jul 2021	Jul 2021	Adjustments	Aug 2021	Aug 2021	Adjustments	Sep 2021	Sep 2021	Adjustments	Oct 2021	Oct 2021				
<b>DEPRECIATION EXPENSE</b>																				
<b>Steam Production Plant:</b>																				
Pre-merger Pacific	SG	6.692%	1,012,491,439	5,646,445	(411,968)	1,012,079,471	5,645,296	(411,968)	1,011,667,503	5,642,998	(411,968)	1,011,255,535	5,640,701	(411,968)	1,010,843,566	5,638,404				
Pre-merger Utah	SG	5.015%	1,059,174,518	4,426,524	(538,554)	1,058,635,963	4,425,398	(538,554)	1,058,097,409	4,423,148	(538,554)	1,057,558,855	4,420,897	(538,554)	1,057,020,301	4,418,646				
Post-merger	SG	6.992%	4,781,690,336	27,861,819	(1,451,787)	4,780,238,549	27,857,590	(745,709)	4,779,492,840	27,851,187	(2,698,237)	4,776,794,603	27,841,154	10,783,833	4,787,578,436	27,864,710				
Geothermal - Blundell	SG	6.992%	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319				
Carbon	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Pollution Control Equipment	SG	6.992%	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Pollution Control Equipment	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Post-merger	SG	0.000%	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-				
Total Steam Plant			6,884,025,173	38,106,107	(2,402,310)	6,881,622,863	38,099,602,79	(1,696,232)	6,879,926,632	38,088,652,44	(3,648,759)	6,876,277,873	38,074,070,70	9,833,310	6,886,111,183	38,093,078,97				
<b>Hydro Production Plant:</b>																				
Pre-merger Pacific	SG	2.210%	183,823,226	338,586	(50,121)	183,773,105	338,540	(50,121)	183,722,984	338,448	(50,121)	183,672,864	338,355	(50,121)	183,622,743	338,263				
Pre-merger Utah	SG	3.181%	39,865,127	105,687	(32,867)	39,832,260	105,644	(32,867)	39,799,393	105,557	(32,867)	39,766,526	105,470	(32,867)	39,733,659	105,382				
Post-merger	SG-P	2.741%	635,303,685	1,450,889	(504,594)	634,799,091	1,450,313	(151,342)	634,647,749	1,449,564	1,089,763	635,737,502	1,450,636	1,777,547	637,515,049	1,453,910				
Post-merger	SG-U	4.692%	152,896,613	597,831	169,637	153,066,250	598,163	(106,448)	152,959,802	598,286	496,010	153,455,812	599,048	227,989	153,683,801	600,463				
Klamath - New Capital	SG-P	20.000%	2,703,876	45,065	-	2,703,876	45,065	-	2,703,876	45,065	-	2,984,900	47,406	73,294	3,058,193	50,359				
Klamath	SG	0.000%	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-				
Total Hydro Plant			1,106,097,117	2,538,059	(417,944)	1,105,679,172	2,537,724	(340,777)	1,105,338,395	2,536,919	1,783,800	1,107,122,194	2,540,915	1,995,842	1,109,118,036	2,548,378				
<b>Other Production Plant:</b>																				
Pre-merger Utah	SG	0.000%	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-				
Post-merger	SG	3.503%	1,925,969,509	5,622,163	(2,125,742)	1,923,843,767	5,619,061	(1,934,710)	1,921,909,056	5,613,134	(2,138,184)	1,919,770,872	5,607,190	26,545,686	1,946,316,558	5,642,814				
Post-merger Wind	SG-W	4.223%	3,160,796,216	11,123,277	30,038,624	3,190,834,840	11,176,132	6,448,004	3,197,282,844	11,240,332	11,542,859	3,208,825,703	11,271,989	18,837,113	3,227,662,816	11,325,444				
Black Cap Solar	OR	0.000%	74,986	-	-	74,986	-	-	74,986	-	-	74,986	-	-	74,986	-				
Post-merger	SG	4.825%	85,640,221	344,357	1,270,934	86,911,154	346,912	(39,401)	86,871,753	349,388	3,255,170	90,126,924	355,853	(39,401)	90,087,523	362,318				
Total Other Plant			5,172,716,061	17,089,797	29,183,815	5,201,899,876	17,142,104,22	4,473,893	5,206,373,769	17,202,854,43	12,659,845	5,219,033,614	17,235,031,18	45,343,398	5,264,377,012	17,330,576,47				
<b>Transmission Plant:</b>																				
Pre-merger Pacific	SG	1.700%	479,801,515	679,681	(168,182)	479,633,333	679,562	(168,182)	479,465,150	679,323	(168,182)	479,296,968	679,085	(168,182)	479,128,786	678,847				
Pre-merger Utah	SG	1.673%	620,673,594	865,294	(295,470)	620,378,125	865,088	(295,470)	620,082,655	864,876	(295,470)	619,787,185	864,264	(295,470)	619,491,716	863,653				
Post-merger	SG	1.724%	6,545,677,086	9,402,321	10,333,361	6,556,010,447	9,409,743	(673,090)	6,555,337,357	9,416,681	17,630,223	6,572,967,580	9,428,859	39,607,968	6,612,575,548	9,489,968				
Total Transmission Plant			7,646,152,195	10,947,296	9,869,709	7,656,021,904	10,954,392,36	(1,136,742)	7,654,885,162	10,960,880,28	17,166,571	7,672,051,734	10,972,208,87	39,144,316	7,711,196,050	11,012,667,66				
<b>Distribution Plant:</b>																				
California	CA	2.704%	290,384,821	654,408	499,707	290,884,529	654,971	390,472	291,275,000	655,974	1,454,890	292,729,890	658,053	1,048,077	293,777,967	660,874				
Oregon	OR	2.271%	2,324,681,909	4,400,159	3,519,013	2,328,200,922	4,403,489	3,650,659	2,331,851,581	4,410,274	15,160,933	2,347,012,514	4,428,078	4,026,463	2,351,038,977	4,446,237				
Washington	WA	2.588%	571,387,038	1,232,462	1,855,530	573,242,568	1,234,463	1,253,696	574,496,264	1,237,916	1,410,468	575,906,732	1,240,690	935,329	576,842,061	1,243,220				
Eastern Wyoming	WYP	2.685%	672,061,808	1,503,917	2,076,156	674,137,963	1,506,240	1,281,841	675,419,805	1,509,997	2,349,680	677,769,484	1,514,061	2,018,870	679,788,354	1,518,948				
Utah	UT	2.540%	3,342,346,441	7,075,743	13,672,154	3,356,018,595	7,090,215	7,135,560	3,363,154,155	7,112,240	22,777,006	3,385,931,161	7,143,903	21,241,539	3,407,172,700	7,190,496				
Idaho	ID	2.561%	397,879,329	849,182	836,267	398,715,596	850,074	991,986	399,707,583	852,025	2,276,625	401,984,208	855,513	3,509,907	404,494,115	861,688				
Western Wyoming	WYU	2.682%	155,050,984	346,494	(27,785)	155,023,199	346,463	(27,785)	154,995,414	346,401	(27,785)	154,967,630	346,339	(27,785)	154,939,845	346,277				
Total Distribution Plant			7,753,792,330	16,062,365	22,431,042	7,776,223,372	16,085,916,17	14,676,430	7,790,899,802	16,124,728,90	45,401,816	7,836,301,618	16,186,636,43	32,752,400	7,869,054,018	16,267,740,03				
<b>General Plant:</b>																				
California	CA	2.021%	22,604,813	38,072	(36,203)	22,568,610	38,041	(23,819)	22,544,791	37,991	(24,813)	22,519,978	37,950	27,109	22,547,087	37,952				
Oregon	OR	2.577%	219,239,049	470,803	(183,854)	219,055,195	470,606	(157,612)	218,897,583	470,239	607,696	219,505,279	470,723	1,150,595	220,655,874	472,610				
Washington	WA	2.371%	46,321,284	91,537	(96,795)	46,224,489	91,441	(118,679)	46,105,810	91,228	194,682	46,300,502	91,303	76,298	46,376,800	91,571				
Eastern Wyoming	WYP	2.539%	80,936,320	171,242	(229,229)	80,707,091	171,000	(42,937)	80,664,154	170,712	348,900	81,013,054	171,035	480,034	81,493,088	171,912				
Utah	UT	2.215%	237,718,891	438,760	64,960	237,783,851	438,820	1,991,241	239,775,092	440,718	723,655	240,498,747	443,223	2,718,045	243,216,792	446,399				
Idaho	ID	1.990%	51,387,414	85,209	(47,717)	51,339,697	85,170	(24,323)	51,315,374	85,110	96,998	51,412,362	85,170	300,719	51,713,081	85,500				
Western Wyoming	WYU	2.182%	18,200,958	33,096	(31,708)	18,169,250	33,067	(31,708)	18,137,543	33,009	(31,708)	18,105,835	32,952	(31,708)	18,074,128	32,894				
Pre-merger Pacific	SG	2.093%	1,007,315	1,757	(13,917)	993,398	1,745	(13,917)	979,480	1,721	(13,917)	965,563	1,696	(13,917)	951,646	1,672				
Pre-merger Utah	SG	1.231%	2,821,996	2,895	(30,778)	2,791,218	2,879	(30,778)	2,760,439	2,847	(30,778)	2,729,661	2,816	(30,778)	2,698,882	2,784				
Post-merger	SG	3.438%	302,412,630	866,305	(300,976)	302,111,654	865,874	(282,844)	301,828,810	865,038	(462,012)	301,366,798	863,971	26,318	301,393,117	863,347				
General Office	SO	5.656%	349,037,338	1,645,217	(561,391)	348,475,947	1,643,894	201,323	348,677,270	1,643,406	4,910,321	353,587,591	1,655,093	23,430,785	377,018,376	1,721,887				
General Office	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
General Office	SG	3.982%	223,232	741	-	223,232	741	-	223,232	741	-	223,232	741	-	223,232	741				
Customer Service	CN	5.953%	17,295,589	85,802	(99,428)	17,196,160	85,555	(99,428)	17,096,732	85,062	(99,428)	16,997,303	84,569	(99,428)	16,897,875	84,075				
Fuel Related	SE	3.632%	3,318,698	10,046	(14,898)	3,303,800	10,023	(14,898)	3,288,902	9,978	(14,898)	3,274,005	9,933	(14,898)	3,259,107	9,888				
Total General Plant			1,352,525,526	3,941,482	(1,581,934)	1,350,943,593	3,938,855,96	1,351,621	1,352,295,213	3,937,439,13	6,204,698	1,358,499,912	3,951,174,28	28,019,175	1,386,519,087	4,023,232,92				
<b>Mining Plant:</b>																				
Coal Mine	SE	0.000%	1,822,901	-	-	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	-	-	1,822,901	-				
Total Depreciation Expense			29,917,131,303	88,685,105	57,082,378	29,974,213,681	88,758,596	17,328,192	29,991,541,874	88,851,274	79,567,971	30,071,109,845	88,960,036	157,088,442	30,228,198,287					

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Description	Factor	2018 Rate	Adjusted EPIS Balance			Depreciation Expense			Adjusted EPIS Balance			Depreciation Expense			Adjusted EPIS Balance			Depreciation Expense		
			Jun 2021	Jun 2021	Adjustments	Jul 2021	Jul 2021	Adjustments	Aug 2021	Aug 2021	Adjustments	Sep 2021	Sep 2021	Adjustments	Oct 2021	Oct 2021				
<b>AMORTIZATION EXPENSE</b>																				
<b>Intangible Plant:</b>																				
California	CA	0.367%	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	
Customer Service	CN	6.456%	214,248,773	1,152,666	(34,194)	214,214,579	1,152,574	(34,194)	214,180,385	1,152,390	(34,194)	214,146,192	1,152,206	(34,194)	214,111,998	1,152,022	-	214,111,998	1,152,022	
Pre-merger Utah	SG	2.611%	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Idaho	ID	0.527%	4,371,145	1,920	(86)	4,371,059	1,920	(86)	4,370,973	1,920	(86)	4,370,886	1,920	(86)	4,370,800	1,920	-	4,370,800	1,920	
Oregon	OR	0.254%	4,616,002	975	(363)	4,615,639	975	(363)	4,615,275	975	(363)	4,614,912	975	(363)	4,614,549	975	-	4,614,549	975	
Fuel Related	SE	20.000%	9,106	152	(4,079)	5,026	118	(4,079)	947	50	(4,079)	(3,132)	(18)	(4,079)	(7,212)	(86)	-	(7,212)	(86)	
Post-merger	SG	3.402%	210,683,247	597,312	(62,928)	210,620,319	597,223	(62,928)	210,557,391	597,044	(62,928)	210,494,464	596,866	(62,928)	210,431,536	596,688	-	210,431,536	596,688	
Hydro Relicensing	SG-P	2.593%	103,455,075	223,537	(4,666)	103,450,409	223,532	(4,666)	103,445,744	223,522	(4,666)	103,441,078	223,512	(4,666)	103,436,412	223,502	-	103,436,412	223,502	
Hydro Relicensing	SG-U	3.225%	10,014,897	26,917	(14,920)	9,999,977	26,897	(14,920)	9,985,056	26,857	(14,920)	9,970,136	26,817	(14,920)	9,955,215	26,777	-	9,955,215	26,777	
General Office	SO	6.156%	432,009,413	2,216,030	1,427,051	433,436,464	2,219,690	(1,972,925)	431,463,539	2,218,290	2,021,630	433,485,169	2,218,415	289,608	433,774,777	2,224,343	-	433,774,777	2,224,343	
Utah	UT	-0.148%	(26,162,598)	3,232	(561)	(26,163,360)	3,232	(561)	(26,163,721)	3,232	(561)	(26,164,283)	3,232	(561)	(26,164,844)	3,233	-	(26,164,844)	3,233	
Washington	WA	0.155%	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	
Eastern Wyoming	WYP	1.960%	5,668,980	9,261	(7,729)	5,661,251	9,254	(7,729)	5,653,523	9,242	(7,729)	5,645,794	9,229	(7,729)	5,638,066	9,217	-	5,638,066	9,217	
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Klamath		0.000%	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-	
Total Intangible Plant			1,036,021,539	4,233,451	1,297,524	1,037,319,063	4,236,865	(2,102,451)	1,035,216,612	4,234,971	1,892,103	1,037,108,715	4,234,603	160,082	1,037,268,798	4,240,038	-	1,037,268,798	4,240,038	
<b>Hydro Production Plant:</b>																				
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Post-merger	SG-P	2.126%	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	
Post-merger	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Hydro Plant			14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	
<b>Other Production Plant:</b>																				
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Other Plant			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
<b>General Plant:</b>																				
California	CA	0.000%	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	
General Office	CN	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Oregon	OR	5.852%	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	
General Office	SO	5.965%	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	
Utah	UT	0.000%	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	
Washington	WA	3.801%	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	
Eastern Wyoming	WYP	1.161%	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total General Plant			14,985,595	48,386	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	
<b>Total Amortization</b>			<b>1,065,666,123</b>	<b>4,307,812</b>	<b>1,297,524</b>	<b>1,066,963,647</b>	<b>4,311,225</b>	<b>(2,102,451)</b>	<b>1,064,861,196</b>	<b>4,309,332</b>	<b>1,892,103</b>	<b>1,066,753,300</b>	<b>4,308,964</b>	<b>160,082</b>	<b>1,066,913,382</b>	<b>4,314,398</b>	<b>-</b>	<b>1,066,913,382</b>	<b>4,314,398</b>	
<b>Total Depreciation &amp; Amortization</b>			<b>30,982,797,426</b>	<b>92,992,916</b>	<b>58,379,902</b>	<b>31,041,177,329</b>	<b>93,069,821</b>	<b>15,225,741</b>	<b>31,056,403,070</b>	<b>93,160,607</b>	<b>81,460,075</b>	<b>31,137,863,145</b>	<b>93,269,000</b>	<b>157,248,524</b>	<b>31,295,111,669</b>	<b>93,590,072</b>	<b>-</b>	<b>31,295,111,669</b>	<b>93,590,072</b>	

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Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjusted EPIS Balance		Depreciation Expense		Adjusted EPIS Balance		Depreciation Expense		Adjusted EPIS Balance		Depreciation Expense		Adjusted EPIS Balance	
			Nov 2021	Nov 2021	Nov 2021	Nov 2021	Dec 2021	Dec 2021	Dec 2021	Dec 2021	Jan 2022	Jan 2022	Jan 2022	Jan 2022	Feb 2022	Feb 2022
<b>DEPRECIATION EXPENSE</b>																
<b>Steam Production Plant:</b>																
Pre-merger Pacific	SG	6.692%	(411,968)	1,010,431.598	5,636,106	(411,968)	1,010,019.630	5,633,809	(411,968)	1,009,607.662	5,631,511	(411,968)	1,009,195.694	5,629,214	(411,968)	1,008,783.726
Pre-merger Utah	SG	5.015%	(538,554)	1,056,481.746	4,416,395	(538,554)	1,055,943.192	4,414,145	(538,554)	1,055,404.638	4,411,894	(538,554)	1,054,866.084	4,409,643	(538,554)	1,054,327.529
Post-merger	SG	6.992%	(342,184)	4,787,236.252	27,895,131	8,121,334	4,795,357.586	27,917,795	(3,677,827)	4,791,679.759	27,930,740	(3,402,284)	4,788,277.475	27,910,113	(3,017,763)	4,785,259.712
Geothermal - Blundell	SG	6.992%	-	29,402.029	171,319	-	29,402.029	171,319	-	29,402.029	171,319	-	29,402.029	171,319	-	29,402.029
Carbon	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	6.992%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	0.000%	-	1,266.851	-	-	1,266.851	-	-	1,266.851	-	-	1,266.851	-	-	1,266.851
<b>Total Steam Plant</b>			<b>(1,292,706)</b>	<b>6,884,818.477</b>	<b>38,118,951.33</b>	<b>7,170,812</b>	<b>6,891,989.289</b>	<b>38,137,066.81</b>	<b>(4,628,349)</b>	<b>6,887,360.939</b>	<b>38,145,464.26</b>	<b>(4,352,807)</b>	<b>6,883,008.133</b>	<b>38,120,288.97</b>	<b>(3,968,286)</b>	<b>6,879,039.847</b>
<b>Hydro Production Plant:</b>																
Pre-merger Pacific	SG	2.210%	(50,121)	183,572.622	338,171	(50,121)	183,522.501	338,078	(50,121)	183,472.380	337,986	(50,121)	183,422.260	337,894	(50,121)	183,372.139
Pre-merger Utah	SG	3.181%	(32,867)	39,700.792	105,295	(32,867)	39,667.926	105,208	(32,867)	39,635.059	105,121	(32,867)	39,602.192	105,034	(32,867)	39,569.325
Post-merger	SG-P	2.741%	3,657.993	641,173.043	1,460,117	13,361,713	654,534,755	1,479,551	(134,488)	654,400,268	1,494,655	2,669,311	657,069,578	1,497,550	1,196,416	658,265,994
Post-merger	SG-U	4.692%	1,352,365	155,036,166	603,553	6,961,581	161,997,747	619,807	(101,594)	161,896,153	633,218	(101,594)	161,794,558	632,821	(101,594)	161,692,964
Klamath - New Capital	SG-P	20.000%	1,112,940	4,171,133	60,244	-	4,171,133	69,519	-	4,171,133	69,519	-	4,171,133	69,519	-	4,171,133
Klamath	SG	0.000%	-	91,504.591	-	-	91,504.591	-	-	91,504.591	-	-	91,504.591	-	-	91,504.591
<b>Total Hydro Plant</b>			<b>6,040,310</b>	<b>1,115,158.347</b>	<b>2,567,380</b>	<b>20,240,306</b>	<b>1,135,398.653</b>	<b>2,612,163</b>	<b>(319,070)</b>	<b>1,135,079.583</b>	<b>2,640,499</b>	<b>2,484,729</b>	<b>1,137,564.312</b>	<b>2,642,817</b>	<b>1,011,834</b>	<b>1,138,576.146</b>
<b>Other Production Plant:</b>																
Pre-merger Utah	SG	0.000%	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	SG	3.503%	(1,732,913)	1,944,583.646	5,679,030	(1,571,078)	1,943,012.568	5,674,208	(2,062,920)	1,940,949.647	5,668,903	(2,062,920)	1,938,886.727	5,662,882	(2,062,920)	1,936,823.807
Post-merger Wind	SG-W	4.223%	3,211,844	3,230,874.661	11,364,241	3,413,055	3,234,287.716	11,375,898	1,002,446	3,235,290.162	11,383,667	1,002,446	3,236,292.608	11,387,195	1,002,446	3,237,295.054
Black Cap Solar	OR	0.000%	-	74,986	-	255,090	330,076	-	5,019	335,095	-	5,019	340,114	-	5,019	345,132
Post-merger	SG	4.825%	(39,401)	90,048.121	362,160	(39,401)	90,008.020	362,001	(42,147)	89,966.573	361,837	(42,147)	89,924.426	361,668	(42,147)	89,882.279
<b>Total Other Plant</b>			<b>1,439,531</b>	<b>5,265,816.543</b>	<b>17,405,430.60</b>	<b>2,057,666</b>	<b>5,267,874.210</b>	<b>17,412,106.74</b>	<b>(1,097,602)</b>	<b>5,266,776.607</b>	<b>17,414,408.10</b>	<b>(1,097,602)</b>	<b>5,265,679.005</b>	<b>17,411,744.44</b>	<b>(1,097,602)</b>	<b>5,264,581,402</b>
<b>Transmission Plant:</b>																
Pre-merger Pacific	SG	1.700%	(168,182)	478,960.604	678,609	(168,182)	478,792.422	678,370	(168,182)	478,624.239	678,132	(168,182)	478,456.057	677,894	(168,182)	478,287.875
Pre-merger Utah	SG	1.673%	(295,470)	619,196.246	863,441	(295,470)	618,900.776	863,029	(295,470)	618,605.307	862,617	(295,470)	618,309.837	862,205	(295,470)	618,014.367
Post-merger	SG	1.724%	40,742,304	6,653,317.852	9,527,677	38,166,406	6,691,484.258	9,584,349	2,920,669	6,694,404.927	9,613,859	4,228,954	6,698,633.881	9,618,993	8,115,236	6,706,749,117
<b>Total Transmission Plant</b>			<b>40,278,653</b>	<b>7,751,474.702</b>	<b>11,069,725.74</b>	<b>37,702,754</b>	<b>7,789,177.457</b>	<b>11,125,748.47</b>	<b>2,457,017</b>	<b>7,791,634.473</b>	<b>11,154,607.39</b>	<b>3,765,302</b>	<b>7,795,399.775</b>	<b>11,159,092.14</b>	<b>7,651,585</b>	<b>7,803,051,360</b>
<b>Distribution Plant:</b>																
California	CA	2.704%	11,314,127	305,092.944	674,803	1,056,089	306,148,183	688,742	881,709	307,029.892	690,925	1,192,832	308,222.724	693,263	3,787,545	312,010,268
Oregon	OR	2.271%	2,922,650	2,353,961.626	4,452,813	8,652,724	2,362,614,351	4,463,768	1,588,700	2,364,203.051	4,473,461	1,935,012	2,366,138.063	4,476,796	13,574,785	2,379,712,848
Washington	WA	2.588%	747,410	577,589.471	1,245,034	1,185,894	578,775,365	1,247,119	762,453	579,537.818	1,249,221	826,112	580,363.930	1,250,934	2,180,310	582,544,240
Eastern Wyoming	WYP	2.685%	1,934,474	681,722.828	1,523,372	13,254,205	694,977,033	1,540,366	1,273,313	696,250,347	1,556,621	1,252,858	697,503,205	1,559,447	1,494,568	698,997,773
Utah	UT	2.540%	10,585,271	3,417,757.971	7,224,185	22,399,037	3,440,157,008	7,259,099	11,050,843	3,451,207,851	7,294,505	14,412,404	3,465,620,255	7,321,458	22,599,508	3,488,219,763
Idaho	ID	2.561%	7,330,647	412,824.762	873,257	2,668,476	415,493,238	883,927	2,436,609	417,929,847	889,375	1,789,296	419,719,143	893,885	2,700,291	422,419,434
Western Wyoming	WYU	2.682%	(27,785)	154,912.060	346,215	(27,785)	154,884,276	346,153	(27,785)	154,856,491	346,091	(27,785)	154,828,706	346,029	(27,785)	154,800,922
<b>Total Distribution Plant</b>			<b>34,806,794</b>	<b>7,903,860.813</b>	<b>16,339,679.37</b>	<b>49,188,641</b>	<b>7,953,049.454</b>	<b>16,429,174.58</b>	<b>17,965,843</b>	<b>7,971,015.296</b>	<b>16,500,198.82</b>	<b>21,380,730</b>	<b>7,992,396.027</b>	<b>16,541,811.32</b>	<b>46,309,222</b>	<b>8,038,705,249</b>
<b>General Plant:</b>																
California	CA	2.021%	(32,129)	22,514,959	37,948	(36,884)	22,478,074	37,890	27,940	22,506,014	37,882	(17,041)	22,488,973	37,891	30,143	22,519,116
Oregon	OR	2.577%	811,710	221,467,584	474,717	7,175,233	228,642,817	483,293	229,532	228,872,349	491,244	(107,779)	228,764,570	491,375	255,379	229,019,949
Washington	WA	2.371%	31,569	46,408,369	91,677	70,377	46,478,746	91,778	(6,346)	46,472,400	91,841	(73,979)	46,398,421	91,762	(2,951)	46,395,470
Eastern Wyoming	WYP	2.539%	244,039	81,737,127	172,678	2,766,378	84,503,505	175,863	294,575	84,798,080	179,101	(24,893)	84,773,187	179,386	16,913	84,790,101
Utah	UT	2.215%	2,427,625	245,644,418	451,148	7,021,627	252,666,045	459,868	2,060,197	254,728,242	468,250	1,222,335	255,948,576	471,279	1,517,713	257,466,290
Idaho	ID	1.990%	208,581	51,921,662	85,922	1,135,561	53,057,223	87,037	149,285	53,206,508	88,102	42,967	53,249,475	88,261	57,433	53,306,909
Western Wyoming	WYU	2.182%	(31,708)	18,042,420	32,836	(31,708)	18,010,713	32,779	(31,708)	17,979,005	32,721	(31,708)	17,947,298	32,663	(31,708)	17,915,590
Pre-merger Pacific	SG	2.093%	(13,917)	937,729	1,648	(13,917)	923,811	1,624	(13,917)	909,894	1,599	(13,917)	895,977	1,575	(13,917)	882,060
Pre-merger Utah	SG	1.231%	(30,778)	2,668,104	2,753	(30,778)	2,637,326	2,721	(30,778)	2,606,547	2,689	(30,778)	2,575,769	2,658	(30,778)	2,544,990
Post-merger	SG	3.438%	378,735	301,771,852	863,927	4,951,199	306,723,051	871,561	(351,727)	306,371,325	878,149	(315,869)	306,055,456	877,193	(272,803)	305,782,654
General Office	SO	5.656%	5,875,563	382,893,939	1,790,956	7,050,289	389,944,228	1,821,419	(52,829)	389,891,399	1,837,911	(72,673)	389,818,727	1,837,615	(575,569)	389,243,158
General Office	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	3.982%	-	223,232	741	-	223,232	741	-	223,232	741	-	223,232	741	-	223,232
Customer Service	CN	5.953%	(99,428)	16,798,447	83,582	(99,428)	16,699,018	83,089	(99,428)	16,599,590	82,596	(99,428)	16,500,161	82,102	(99,428)	16,400,733
Fuel Related	SE	3.632%	(14,898)	3,244,210	9,843	(14,898)	3,229,312	9,798	(14,898)	3,214,414	9,753	(14,898)	3,199,517	9,708	(14,898)	3,184,619
<b>Total General Plant</b>			<b>9,754,964</b>	<b>1,396,274,051</b>	<b>4,100,376.49</b>	<b>29,943,051</b>	<b>1,426,217,102</b>	<b>4,159,460.10</b>	<b>2,159,897</b>	<b>1,428,376.999</b>	<b>4,202,578.71</b>	<b>462,340</b>	<b>1,428,839.339</b>	<b>4,204,209.39</b>	<b>835,531</b>	<b>1,429,674,871</b>
<b>Mining Plant:</b>																
Coal Mine	SE	0.000%	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,82



PacifiCorp  
Oregon General Rate Case - December 2023  
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjusted EPIS Balance		Depreciation Expense		Adjusted EPIS Balance		Depreciation Expense		Adjusted EPIS Balance		Depreciation Expense		Adjusted EPIS Balance	
			Adjustments	Nov 2021	Nov 2021	Adjustments	Dec 2021	Dec 2021	Adjustments	Jan 2022	Jan 2022	Adjustments	Feb 2022	Feb 2022	Adjustments	Mar 2022
<b>AMORTIZATION EXPENSE</b>																
<b>Intangible Plant:</b>																
California	CA	0.367%	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167
Customer Service	CN	6.456%	(34,194)	214,077,804	1,151,838	(34,194)	214,043,611	1,151,654	(34,194)	214,009,417	1,151,470	(34,194)	213,975,223	1,151,286	(34,194)	213,941,030
Pre-merger Utah	SG	2.611%	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	0.527%	(86)	4,370,714	1,920	(86)	4,370,628	1,920	(86)	4,370,541	1,920	(86)	4,370,455	1,920	(86)	4,370,369
Oregon	OR	0.254%	(363)	4,614,186	975	(363)	4,613,822	975	(363)	4,613,459	975	(363)	4,613,096	975	(363)	4,612,732
Fuel Related	SE	20.000%	(4,079)	(11,291)	(154)	(4,079)	(15,371)	(222)	(4,079)	(19,450)	(290)	(4,079)	(23,529)	(358)	(4,079)	(27,609)
Post-merger	SG	3.402%	(62,928)	210,368,609	596,509	(62,928)	210,305,681	596,331	(62,928)	210,242,753	596,152	(62,928)	210,179,826	595,974	(62,928)	210,116,898
Hydro Relicensing	SG-P	2.593%	(4,666)	103,431,747	223,492	(4,666)	103,427,081	223,482	(4,666)	103,422,416	223,472	(4,666)	103,417,750	223,461	(4,666)	103,413,085
Hydro Relicensing	SG-U	3.225%	(14,920)	9,940,295	26,737	(14,920)	9,925,374	26,697	(14,920)	9,910,454	26,657	(14,920)	9,895,534	26,617	(14,920)	9,880,613
General Office	SO	6.156%	7,685,914	441,460,691	2,244,799	5,117,782	446,578,473	2,277,638	3,078,781	449,657,253	2,298,660	(596,409)	449,060,844	2,305,027	223,691	449,284,535
Utah	UT	-0.148%	(561)	(26,165,405)	3,233	(561)	(26,165,967)	3,233	(561)	(26,166,528)	3,233	(561)	(26,167,090)	3,233	(561)	(26,167,651)
Washington	WA	0.155%	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986
Eastern Wyoming	WYP	1.960%	(7,729)	5,630,337	9,204	(7,729)	5,622,608	9,191	(7,729)	5,614,880	9,179	(7,729)	5,607,151	9,166	(7,729)	5,599,423
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath		0.000%	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750
Total Intangible Plant			7,556,388	1,044,825,185	4,260,000	4,988,256	1,049,813,441	4,292,346	2,949,254	1,052,762,695	4,312,875	(725,936)	1,052,036,760	4,318,748	94,164	1,052,130,924
<b>Hydro Production Plant:</b>																
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.126%	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989
Post-merger	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989
<b>Other Production Plant:</b>																
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>General Plant:</b>																
California	CA	0.000%	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860
General Office	CN	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	5.852%	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847
General Office	SO	5.965%	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339
Utah	UT	0.000%	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127
Washington	WA	3.801%	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816
Eastern Wyoming	WYP	1.161%	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant			-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595
<b>Total Amortization</b>			<b>7,556,388</b>	<b>1,074,469,769</b>	<b>4,334,361</b>	<b>4,988,256</b>	<b>1,079,458,025</b>	<b>4,366,706</b>	<b>2,949,254</b>	<b>1,082,407,279</b>	<b>4,387,236</b>	<b>(725,936)</b>	<b>1,081,681,344</b>	<b>4,393,109</b>	<b>94,164</b>	<b>1,081,775,508</b>
<b>Total Depreciation &amp; Amortization</b>			<b>98,583,934</b>	<b>31,393,695,603</b>	<b>93,935,904</b>	<b>151,291,487</b>	<b>31,544,987,089</b>	<b>94,242,427</b>	<b>19,486,990</b>	<b>31,564,474,079</b>	<b>94,444,992</b>	<b>21,916,756</b>	<b>31,586,390,835</b>	<b>94,473,073</b>	<b>50,836,448</b>	<b>31,637,227,283</b>

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Jun 2021 - Dec 2022 Depreciation & Amortization Expense**

Description	Factor	2018 Rate	Depreciation Expense		Adjusted EPIS Balance		Depreciation Expense		Adjusted EPIS Balance		Depreciation Expense		Adjusted EPIS Balance		Depreciation Expense		Adjusted EPIS Balance		
			Mar 2022	Adjustments	Apr 2022	Apr 2022	Adjustments	May 2022	May 2022	Adjustments	Jun 2022	Jun 2022	Adjustments	Jul 2022	Jul 2022	Adjustments			
<b>DEPRECIATION EXPENSE</b>																			
<b>Steam Production Plant:</b>																			
Pre-merger Pacific	SG	6.692%	5,626,916	(411,968)	1,008,371,757	5,624,619	(411,968)	1,007,959,789	5,622,321	(411,968)	1,007,547,821	5,620,024	(411,968)	1,007,135,853	5,617,726	(411,968)			
Pre-merger Utah	SG	5.015%	4,407,392	(538,554)	1,053,788,975	4,405,142	(538,554)	1,053,250,421	4,402,891	(538,554)	1,052,711,867	4,400,640	(538,554)	1,052,173,312	4,398,390	(538,554)			
Post-merger	SG	6.992%	27,891,409	20,453,230	4,805,712,942	27,942,205	33,139,910	4,838,852,852	28,098,343	11,264,526	4,850,117,378	28,227,710	2,791,402	4,852,908,780	28,268,660	(3,421,544)			
Geothermal - Blundell	SG	6.992%	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-			
Carbon	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Pollution Control Equipment	SG	6.992%	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Pollution Control Equipment	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Post-merger	SG	0.000%	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-			
<b>Total Steam Plant</b>			<b>38,097,036.70</b>	<b>19,502,708</b>	<b>6,898,542,555</b>	<b>38,143,284.76</b>	<b>32,189,388</b>	<b>6,930,731,943</b>	<b>38,294,874.07</b>	<b>10,314,004</b>	<b>6,941,045,946</b>	<b>38,419,693.13</b>	<b>1,840,880</b>	<b>6,942,886,826</b>	<b>38,456,095.28</b>	<b>(4,372,067)</b>			
<b>Hydro Production Plant:</b>																			
Pre-merger Pacific	SG	2.210%	337,801	(50,121)	183,322,018	337,709	(50,121)	183,271,897	337,617	(50,121)	183,221,776	337,525	(50,121)	183,171,656	337,432	(50,121)			
Pre-merger Utah	SG	3.181%	104,947	(32,867)	39,536,458	104,860	(32,867)	39,503,591	104,773	(32,867)	39,470,725	104,685	(32,867)	39,437,858	104,598	(32,867)			
Post-merger	SG-P	2.741%	1,501,964	185,405	658,451,399	1,503,542	598,587	659,049,986	1,504,437	11,713,429	670,763,416	1,518,496	198,929	670,962,344	1,532,099	7,040,461			
Post-merger	SG-U	4.692%	632,424	(101,594)	161,591,370	632,026	(101,594)	161,489,775	631,629	(32,229)	161,457,546	631,367	1,125,735	162,583,282	633,505	(101,594)			
Klamath - New Capital	SG-P	20.000%	69,519	-	4,171,133	69,519	-	4,171,133	69,519	-	4,171,133	69,519	-	4,171,133	69,519	-			
Klamath	0.000%	-	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-			
<b>Total Hydro Plant</b>			<b>2,646,655</b>	<b>823</b>	<b>1,138,576,969</b>	<b>2,647,656</b>	<b>414,005</b>	<b>1,138,990,974</b>	<b>2,647,974</b>	<b>11,598,213</b>	<b>1,150,589,187</b>	<b>2,661,592</b>	<b>1,241,676</b>	<b>1,151,830,863</b>	<b>2,677,153</b>	<b>6,855,879</b>			
<b>Other Production Plant:</b>																			
Pre-merger Utah	SG	0.000%	-	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-	-			
Post-merger	SG	3.503%	5,656,860	21,353,942	1,958,177,749	5,685,016	1,498,455	1,959,676,204	5,718,371	(1,126,057)	1,958,550,147	5,718,914	(1,817,864)	1,956,732,283	5,714,617	(2,057,700)			
Post-merger Wind	SG-W	4.223%	11,390,723	1,002,446	3,238,297,500	11,394,251	1,057,446	3,239,354,946	11,397,875	1,002,446	3,240,357,392	11,401,500	1,002,446	3,241,359,838	11,405,027	1,002,446			
Black Cap Solar	OR	0.000%	-	5,019	350,151	-	5,019	355,170	-	5,019	360,189	-	5,019	365,207	-	5,019			
Post-merger	SG	4.825%	361,498	(42,147)	89,840,132	361,329	(42,147)	89,797,985	361,159	(19,753)	89,778,232	361,035	(42,147)	89,736,085	360,911	(42,147)			
<b>Total Other Plant</b>			<b>17,409,080.77</b>	<b>22,319,260</b>	<b>5,286,900,662</b>	<b>17,440,595.58</b>	<b>2,518,773</b>	<b>5,289,419,434</b>	<b>17,477,405.24</b>	<b>(138,348)</b>	<b>5,289,281,089</b>	<b>17,481,448.85</b>	<b>(852,546)</b>	<b>5,288,428,542</b>	<b>17,480,555.30</b>	<b>(1,092,382)</b>			
<b>Transmission Plant:</b>																			
Pre-merger Pacific	SG	1.700%	677,656	(168,182)	478,119,693	677,417	(168,182)	477,951,511	677,179	(168,182)	477,783,329	676,944	(168,182)	477,615,146	676,703	(168,182)			
Pre-merger Utah	SG	1.673%	861,793	(295,470)	617,718,898	861,381	(295,470)	617,423,428	860,969	(295,470)	617,127,958	860,557	(295,470)	616,832,489	860,145	(295,470)			
Post-merger	SG	1.724%	9,627,859	10,922,632	6,717,671,749	9,641,532	28,377,815	6,746,049,564	9,669,758	18,631,954	6,764,681,518	9,703,521	38,591,372	6,803,272,890	9,744,619	15,815,183			
<b>Total Transmission Plant</b>			<b>11,167,307.68</b>	<b>10,458,980</b>	<b>7,813,510,340</b>	<b>11,180,330.67</b>	<b>27,914,163</b>	<b>7,841,424,503</b>	<b>11,207,906.42</b>	<b>18,168,302</b>	<b>7,859,592,805</b>	<b>11,241,019.07</b>	<b>38,127,720</b>	<b>7,897,720,525</b>	<b>11,281,467.18</b>	<b>15,351,532</b>			
<b>Distribution Plant:</b>																			
California	CA	2.704%	698,875	1,032,357	313,042,626	704,306	5,565,135	318,607,761	711,740	6,749,241	325,357,002	725,616	4,952,388	330,309,390	738,801	737,552			
Oregon	OR	2.271%	4,491,474	5,440,658	2,385,153,507	4,509,470	27,394,986	2,412,548,493	4,540,546	18,831,691	2,431,380,183	4,584,295	10,538,021	2,441,918,204	4,612,090	5,828,050			
Washington	WA	2.588%	1,254,176	1,843,889	584,388,128	1,258,516	2,894,407	587,282,535	1,263,627	2,745,527	590,028,062	1,269,709	19,674,340	609,702,402	1,293,889	1,638,668			
Eastern Wyoming	WYP	2.685%	1,562,521	1,637,015	700,634,788	1,566,025	2,337,306	702,972,094	1,570,472	1,925,179	704,897,274	1,575,241	1,804,819	706,702,093	1,579,415	2,094,681			
Utah	UT	2.540%	7,360,635	15,699,539	3,503,919,302	7,401,175	34,281,300	3,538,200,602	7,454,080	19,992,362	3,557,792,964	7,511,105	16,819,169	3,574,612,134	7,549,646	15,227,001			
Idaho	ID	2.561%	898,676	2,077,140	424,496,574	903,774	3,053,427	427,550,001	909,249	1,999,241	429,549,241	914,641	2,019,668	431,568,909	918,929	2,027,729			
Western Wyoming	WYU	2.682%	345,967	(27,785)	154,773,137	345,904	(27,785)	154,745,352	345,842	(27,785)	154,717,568	345,780	(27,785)	154,689,783	345,718	(27,785)			
<b>Total Distribution Plant</b>			<b>16,612,324.07</b>	<b>27,702,812</b>	<b>8,066,408,061</b>	<b>16,689,170.82</b>	<b>75,498,777</b>	<b>8,141,906,838</b>	<b>16,795,565.07</b>	<b>51,815,456</b>	<b>8,193,722,295</b>	<b>16,926,386.59</b>	<b>55,780,620</b>	<b>8,249,002,914</b>	<b>17,038,488.50</b>	<b>27,525,896</b>			
<b>General Plant:</b>																			
California	CA	2.021%	37,902	(26,597)	22,492,519	37,905	(6,915)	22,485,604	37,877	37,130	22,522,734	37,902	74,104	22,596,839	37,996	322,168			
Oregon	OR	2.577%	491,533	461,547	229,481,496	492,303	652,889	230,134,386	493,499	1,144,411	231,278,797	495,429	775,644	232,054,441	497,491	440,656			
Washington	WA	2.371%	91,686	(18,788)	46,376,682	91,665	13,859	46,390,541	91,660	100,356	46,490,897	91,773	70,969	46,561,866	91,942	(14,324)			
Eastern Wyoming	WYP	2.539%	179,378	190,157	84,980,258	179,597	309,960	85,290,217	180,126	471,432	85,761,650	180,953	95,098	85,856,747	181,552	504,003			
Utah	UT	2.215%	473,808	1,763,441	259,229,731	476,836	2,574,412	261,804,142	480,839	2,972,976	264,777,119	485,958	2,319,195	267,096,313	490,842	1,317,607			
Idaho	ID	1.990%	88,344	56,532	53,363,441	88,439	96,578	53,460,019	88,566	150,958	53,610,977	88,771	83,534	53,694,511	88,965	150,189			
Western Wyoming	WYU	2.182%	32,606	(31,708)	17,883,883	32,548	(31,708)	17,852,175	32,490	(31,708)	17,820,467	32,433	(31,708)	17,788,760	32,375	(31,708)			
Pre-merger Pacific	SG	2.093%	1,551	(13,917)	868,143	1,526	(13,917)	854,225	1,502	(13,917)	840,308	1,478	(13,917)	826,391	1,454	(13,917)			
Pre-merger Utah	SG	1.231%	2,626	(30,778)	2,514,212	2,595	(30,778)	2,483,433	2,563	(30,778)	2,452,655	2,532	(30,778)	2,421,877	2,500	(30,778)			
Post-merger	SG	3.438%	876,350	(228,856)	305,553,798	875,631	(272,771)	305,281,027	874,913	(272,457)	305,008,570	874,132	(271,142)	304,737,429	873,353	(280,017)			
General Office	SO	5.656%	1,836,087	93,518	389,336,676	1,834,951	1,131,631	390,468,308	1,837,839	3,035,787	393,504,095	1,847,660	363,699	393,867,794	1,855,672	(171,889)			
General Office	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
General Office	SG	3.982%	741	-	223,232	741	-	223,232	741	-	223,232	741	-	223,232	741	-			
Customer Service	CN	5.953%	81,609	(99,428)	16,301,304	81,116	(99,428)	16,201,876	80,623	(99,428)	16,102,447	80,129	(99,428)	16,003,019	79,636	(99,428)			
Fuel Related	SE	3.632%	9,663	(14,898)	3,169,722	9,617	(14,898)	3,154,824	9,572	(14,898)	3,139,927	9,527	(14,898)						

PacifiCorp  
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Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Depreciation Expense			Adjusted EPIS Balance			Depreciation Expense			Adjusted EPIS Balance			Depreciation Expense			Adjusted EPIS Balance		
			Mar 2022	Adjustments	Apr 2022	Apr 2022	Apr 2022	Adjustments	May 2022	May 2022	Adjustments	Jun 2022	Jun 2022	Adjustments	Jul 2022	Jul 2022	Adjustments			
<b>AMORTIZATION EXPENSE</b>																				
<b>Intangible Plant:</b>																				
California	CA	0.367%	147	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	-	
Customer Service	CN	6.456%	1,151,102	(34,194)	213,906,836	1,150,918	(34,194)	213,872,642	1,150,734	(34,194)	213,838,449	1,150,550	(34,194)	213,804,255	1,150,366	(34,194)	213,770,061	1,150,182	(34,194)	
Pre-merger Utah	SG	2.611%	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Idaho	ID	0.527%	1,920	(86)	4,370,283	1,920	(86)	4,370,196	1,920	(86)	4,370,110	1,920	(86)	4,370,024	1,920	(86)	4,370,024	1,920	(86)	
Oregon	OR	0.254%	975	(363)	4,612,369	975	(363)	4,612,006	974	(363)	4,611,642	974	(363)	4,611,279	974	(363)	4,611,279	974	(363)	
Fuel Related	SE	20.000%	(426)	(4,079)	(31,688)	(494)	(4,079)	(35,767)	(562)	(4,079)	(39,847)	(630)	(4,079)	(43,926)	(698)	(4,079)	(43,926)	(698)	(4,079)	
Post-merger	SG	3.402%	595,796	(62,928)	210,053,970	595,617	(62,928)	209,991,043	595,439	(62,928)	209,928,115	595,260	(62,928)	209,865,187	595,082	(62,928)	209,802,259	594,904	(62,928)	
Hydro Relicensing	SG-P	2.593%	223,451	(4,666)	103,408,419	223,441	(4,666)	103,403,753	223,431	(4,666)	103,399,088	223,421	(4,666)	103,394,422	223,411	(4,666)	103,389,756	223,401	(4,666)	
Hydro Relicensing	SG-U	3.225%	26,577	(14,920)	9,865,693	26,536	(14,920)	9,850,772	26,496	(14,920)	9,835,852	26,456	(14,920)	9,820,931	26,416	(14,920)	9,806,010	26,376	(14,920)	
General Office	SO	6.156%	2,304,071	435,497	449,720,031	2,305,762	(38,349)	449,681,682	2,306,780	(38,349)	449,643,333	2,307,800	(38,349)	449,604,984	2,308,818	(38,349)	449,566,635	2,309,837	(38,349)	
Utah	UT	-0.148%	3,233	(561)	(26,168,212)	3,233	(561)	(26,168,774)	3,233	(561)	(26,169,335)	3,233	(561)	(26,169,897)	3,233	(561)	(26,170,420)	3,233	(561)	
Washington	WA	0.155%	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	
Eastern Wyoming	WYP	1.960%	9,153	(7,729)	5,591,694	9,141	(7,729)	5,583,966	9,128	(7,729)	5,576,237	9,116	(7,729)	5,568,509	9,103	(7,729)	5,560,780	9,090	(7,729)	
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Klamath		0.000%	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	
Total Intangible Plant			4,317,299	305,970	1,052,436,894	4,318,497	(167,876)	1,052,269,019	4,319,022	12,476,227	1,064,745,246	4,350,762	(450,306)	1,064,294,941	4,381,777	(513,256)	1,063,781,685	4,453,033	(576,512)	
<b>Hydro Production Plant:</b>																				
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Post-merger	SG-P	2.126%	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	
Post-merger	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Hydro Plant			25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	
<b>Other Production Plant:</b>																				
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Other Plant			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
<b>General Plant:</b>																				
California	CA	0.000%	-	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	-	
General Office	CN	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Oregon	OR	5.852%	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	
General Office	SO	5.965%	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	
Utah	UT	0.000%	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	
Washington	WA	3.801%	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	
Eastern Wyoming	WYP	1.161%	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total General Plant			48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	
<b>Total Amortization</b>			<b>4,391,660</b>	<b>305,970</b>	<b>1,082,081,479</b>	<b>4,392,858</b>	<b>(167,876)</b>	<b>1,081,913,603</b>	<b>4,393,383</b>	<b>12,476,227</b>	<b>1,094,389,831</b>	<b>4,425,123</b>	<b>(450,306)</b>	<b>1,093,939,525</b>	<b>4,456,138</b>	<b>(513,256)</b>	<b>1,093,426,269</b>	<b>4,532,874</b>	<b>(626,788)</b>	
<b>Total Depreciation &amp; Amortization</b>			<b>94,527,948</b>	<b>82,390,779</b>	<b>31,719,618,062</b>	<b>94,699,365</b>	<b>142,676,146</b>	<b>31,862,294,208</b>	<b>95,029,908</b>	<b>111,683,721</b>	<b>31,973,977,929</b>	<b>95,384,681</b>	<b>99,008,415</b>	<b>32,072,986,344</b>	<b>95,633,899</b>	<b>45,833,268</b>	<b>32,168,822,612</b>	<b>96,067,162</b>	<b>46,366,536</b>	

PacifiCorp  
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Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjusted EPIS Balance			Depreciation Expense			Adjusted EPIS Balance			Depreciation Expense			Adjusted EPIS Balance			Depreciation Expense		
			Aug 2022	Aug 2022	Adjustments	Sep 2022	Sep 2022	Adjustments	Oct 2022	Oct 2022	Adjustments	Nov 2022	Nov 2022	Adjustments	Dec 2022	Dec 2022				
<b>DEPRECIATION EXPENSE</b>																				
<b>Steam Production Plant:</b>																				
Pre-merger Pacific	SG	6.692%	1,006,723,885	5,615,429	(411,968)	1,006,311,917	5,613,132	(411,968)	1,005,899,948	5,610,834	(411,968)	1,005,487,980	5,608,537	(411,968)	1,005,076,012	5,606,239				
Pre-merger Utah	SG	5.015%	1,051,634,758	4,396,139	(538,554)	1,051,096,204	4,393,888	(538,554)	1,050,557,650	4,391,637	(538,554)	1,050,019,095	4,389,387	(538,554)	1,049,480,541	4,387,136				
Post-merger	SG	6.992%	4,849,487,236	28,266,825	(2,995,353)	4,846,491,883	28,248,130	989,081	4,847,480,964	28,242,285	4,671,246	4,852,152,210	28,258,775	12,849,455	4,865,001,665	28,309,820				
Geothermal - Blundell	SG	6.992%	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319				
Carbon	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Pollution Control Equipment	SG	6.992%	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Pollution Control Equipment	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
Post-merger	SG	0.000%	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-				
Total Steam Plant			6,938,514,759	38,449,711.24	(3,945,876)	6,934,568,884	38,426,468.15	38,559	6,934,607,442	38,416,074.91	3,720,724	6,938,328,166	38,428,017.43	11,898,933	6,950,227,099	38,474,513.81				
<b>Hydro Production Plant:</b>																				
Pre-merger Pacific	SG	2.210%	183,121,535	337,340	(50,121)	183,071,414	337,248	(50,121)	183,021,293	337,155	(50,121)	182,971,172	337,063	(50,121)	182,921,052	336,971				
Pre-merger Utah	SG	3.181%	39,404,991	104,511	(32,867)	39,372,124	104,424	(32,867)	39,339,257	104,337	(32,867)	39,306,390	104,250	(32,867)	39,273,524	104,163				
Post-merger	SG-P	2.741%	678,002,805	1,540,365	187,933	678,190,738	1,548,819	1,411,337	679,602,075	1,550,445	5,114,339	684,716,415	1,557,897	27,729,937	712,446,352	1,595,401				
Post-merger	SG-U	4.692%	162,481,687	635,507	(101,594)	162,380,093	635,110	3,396,591	165,776,684	641,552	(52,907)	165,723,777	648,089	17,582,814	183,286,592	682,321				
Klamath - New Capital	SG-P	20.000%	4,171,133	69,519	-	4,171,133	69,519	-	4,171,133	69,519	3,493,814	7,664,947	98,634	1,982,716	9,647,664	144,272				
Klamath	0.000%	91,504,591	-	-	91,504,591	-	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-				
Total Hydro Plant			1,158,686,742	2,687,242	3,351	1,158,690,093	2,694,920	4,724,941	1,163,415,034	2,703,008	8,472,259	1,171,887,293	2,745,932	47,192,480	1,219,079,773	2,863,127				
<b>Other Production Plant:</b>																				
Pre-merger Utah	SG	0.000%	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-				
Post-merger	SG	3.503%	1,954,674,583	5,708,961	(2,057,700)	1,952,616,883	5,702,954	757,437	1,953,374,320	5,701,056	(2,057,700)	1,951,316,621	5,699,158	4,809,958	1,956,126,579	5,703,176				
Post-merger Wind	SG-W	4.223%	3,242,362,283	11,408,555	1,002,446	3,243,364,729	11,412,083	1,002,446	3,244,367,175	11,415,611	1,002,446	3,245,369,621	11,419,138	1,002,446	3,246,372,067	11,422,666				
Black Cap Solar	OR	0.000%	370,226	-	5,019	375,245	-	5,019	380,264	-	5,019	385,282	-	5,019	390,301	-				
Post-merger	SG	4.825%	89,693,938	360,741	(42,147)	89,651,791	360,572	(42,147)	89,609,644	360,402	(42,147)	89,567,497	360,233	20,439	89,587,935	360,189				
Total Other Plant			5,287,336,160	17,478,256.93	(1,092,382)	5,286,243,778	17,475,608.50	1,722,755	5,287,966,533	17,477,068.95	(1,092,382)	5,286,874,150	17,478,529.40	5,837,862	5,292,712,012	17,486,030.61				
<b>Transmission Plant:</b>																				
Pre-merger Pacific	SG	1.700%	477,446,964	676,464	(168,182)	477,278,782	676,226	(168,182)	477,110,600	675,988	(168,182)	476,942,418	675,750	(168,182)	476,774,235	675,511				
Pre-merger Utah	SG	1.673%	616,537,019	859,733	(295,470)	616,241,549	859,321	(295,470)	615,946,080	858,909	(295,470)	615,650,610	858,498	(295,470)	615,355,140	858,086				
Post-merger	SG	1.724%	6,819,088,074	9,783,695	16,092,947	6,835,181,021	9,806,611	30,671,034	6,865,852,054	9,840,198	41,234,807	6,907,086,862	9,891,841	44,869,272	6,951,956,134	9,953,682				
Total Transmission Plant			7,913,072,057	11,319,892.26	15,629,295	7,928,701,352	11,342,158.78	30,207,382	7,958,908,734	11,375,094.90	40,771,156	7,999,679,890	11,426,088.12	44,405,620	8,044,085,510	11,487,278.63				
<b>Distribution Plant:</b>																				
California	CA	2.704%	331,046,942	745,212	823,811	331,870,753	746,972	2,040,972	333,911,724	750,200	1,672,946	335,584,670	754,385	6,614,111	342,198,781	763,722				
Oregon	OR	2.271%	2,447,746,254	4,627,579	10,039,794	2,457,786,048	4,642,597	5,759,640	2,463,545,688	4,657,549	4,365,110	2,467,910,797	4,667,131	16,417,329	2,484,328,127	4,686,800				
Washington	WA	2.588%	611,341,070	1,316,874	1,044,016	612,385,087	1,319,767	1,287,687	613,672,774	1,322,282	1,124,687	614,797,460	1,324,884	4,613,975	619,411,435	1,331,073				
Eastern Wyoming	WYP	2.685%	708,796,773	1,583,778	1,910,503	710,707,276	1,588,259	1,706,716	712,613,993	1,592,306	1,559,003	713,972,995	1,595,960	2,037,706	716,010,701	1,599,985				
Utah	UT	2.540%	3,589,839,134	7,583,567	14,330,857	3,604,169,991	7,614,854	22,009,376	3,626,179,367	7,653,320	25,375,579	3,651,554,946	7,703,477	19,772,073	3,671,327,019	7,751,266				
Idaho	ID	2.561%	433,596,638	923,248	2,751,098	436,347,737	928,348	2,072,825	438,420,561	933,496	1,799,694	440,220,256	937,628	4,123,486	444,343,741	943,949				
Western Wyoming	WYU	2.682%	154,661,999	345,656	(27,785)	154,634,214	345,594	(27,785)	154,606,429	345,532	(27,785)	154,578,645	345,470	(27,785)	154,550,860	345,408				
Total Distribution Plant			8,277,028,811	17,125,915.42	30,872,295	8,307,901,106	17,186,391.18	34,849,430	8,342,750,536	17,254,685.53	35,869,233	8,378,619,770	17,328,935.43	53,550,895	8,432,170,664	17,422,202.59				
<b>General Plant:</b>																				
California	CA	2.021%	22,919,007	38,330	93,132	23,012,139	38,680	65,976	23,078,115	38,813	46,603	23,124,718	38,908	328,809	23,454,527	39,225				
Oregon	OR	2.577%	232,495,096	498,797	782,824	233,277,921	500,110	680,009	233,957,929	501,681	1,158,966	235,116,896	503,656	3,550,850	238,667,745	508,713				
Washington	WA	2.371%	46,547,543	91,998	264,909	46,812,451	92,245	7,467	46,819,918	92,515	(24,443)	46,795,475	92,498	334,676	47,130,151	92,804				
Eastern Wyoming	WYP	2.539%	86,360,751	182,186	186,412	86,547,162	182,916	300,225	86,847,388	183,431	863,318	87,710,706	184,662	1,164,488	88,875,194	186,807				
Utah	UT	2.215%	268,413,920	494,198	1,857,229	270,271,149	497,128	1,853,285	272,124,434	500,553	1,610,688	273,735,122	503,749	3,972,042	277,707,164	508,901				
Idaho	ID	1.990%	53,844,700	89,159	98,136	53,942,836	89,365	150,448	54,093,284	89,571	217,098	54,310,382	89,876	574,710	54,885,092	90,532				
Western Wyoming	WYU	2.182%	17,757,052	32,317	(31,708)	17,725,345	32,260	(31,708)	17,693,637	32,202	(31,708)	17,661,930	32,144	(31,708)	17,630,222	32,087				
Pre-merger Pacific	SG	2.093%	812,474	1,429	(13,917)	798,556	1,405	(13,917)	784,639	1,381	(13,917)	770,722	1,357	(13,917)	756,805	1,332				
Pre-merger Utah	SG	1.231%	2,391,098	2,468	(30,778)	2,360,320	2,437	(30,778)	2,329,541	2,405	(30,778)	2,298,763	2,374	(30,778)	2,267,985	2,342				
Post-merger	SG	3.438%	304,457,412	872,564	66,636	304,524,048	872,258	218,262	304,742,310	872,666	1,343,547	306,085,857	874,903	5,607,129	311,692,986	884,859				
General Office	SO	5.656%	393,695,905	1,856,124	638,391	394,334,296	1,857,224	3,427,081	397,761,378	1,866,805	236,944	397,998,322	1,875,441	6,911,058	404,909,380	1,892,287				
General Office	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-				
General Office	SG	3.982%	223,232	741	-	223,232	741	-	223,232	741	-	223,232	741	-	223,232	741				
Customer Service	CN	5.953%	15,903,591	79,143	(99,428)	15,804,162	78,650	(99,428)	15,704,734	78,156	(99,428)	15,605,305	77,663	(99,428)	15,505,877	77,170				
Fuel Related	SE	3.632%	3,110,131	9,437	(14,898)	3,095,234	9,392	(14,898)	3,080,336	9,347	(14,898)	3,065,439	9,302	(14,898)	3,050,541	9,257				
Total General Plant			1,448,931,912	4,248,891.90	3,796,939	1,452,728,852	4,254,811.04	6,512,024	1,459,240,876	4,270,267.68	5,261,992	1,464,502,868	4,287,273.13	22,254,033	1,486,756,901	4,327,057.50				
<b>Mining Plant:</b>																				
Coal Mine	SE	0.000%	1,822,901	-	-	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	-	-	1,822,901	-				
Total Depreciation Expense			31,025,393,342	91,309,910	45,263,623	31,070,656,965	91,380,357	78,055,090	31,148,712,055	91,496,200	93,002,982	31								

PacifiCorp  
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Description	Factor	2018 Rate	Adjusted EPIS Balance			Depreciation Expense			Adjusted EPIS Balance			Depreciation Expense			Adjusted EPIS Balance			Depreciation Expense		
			Aug 2022	Aug 2022	Adjustments	Sep 2022	Sep 2022	Adjustments	Oct 2022	Oct 2022	Adjustments	Nov 2022	Nov 2022	Adjustments	Dec 2022	Dec 2022				
<b>AMORTIZATION EXPENSE</b>																				
<b>Intangible Plant:</b>																				
California	CA	0.367%	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	
Customer Service	CN	6.456%	213,770,061	1,150,182	(34,194)	213,735,868	1,149,998	(34,194)	213,701,674	1,149,814	(34,194)	213,667,480	1,149,630	(34,194)	213,633,287	1,149,446	-	213,633,287	1,149,446	
Pre-merger Utah	SG	2.611%	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Idaho	ID	0.527%	4,369,938	1,920	(86)	4,369,851	1,920	(86)	4,369,765	1,920	(86)	4,369,679	1,920	(86)	4,369,593	1,919	-	4,369,593	1,919	
Oregon	OR	0.254%	4,610,916	974	(363)	4,610,553	974	(363)	4,610,189	974	(363)	4,609,826	974	(363)	4,609,463	974	-	4,609,463	974	
Fuel Related	SE	20.000%	(48,006)	(766)	(4,079)	(52,085)	(834)	(4,079)	(56,164)	(902)	(4,079)	(60,244)	(970)	(4,079)	(64,323)	(1,038)	-	(64,323)	(1,038)	
Post-merger	SG	3.402%	209,802,260	594,904	(62,928)	209,739,332	594,725	(62,928)	209,676,404	594,547	(62,928)	209,613,477	594,368	(62,928)	209,550,549	594,190	-	209,550,549	594,190	
Hydro Relicensing	SG-P	2.593%	103,389,757	223,401	(4,666)	103,385,091	223,391	(4,666)	103,380,425	223,381	(4,666)	103,375,760	223,371	(4,666)	103,371,094	223,361	-	103,371,094	223,361	
Hydro Relicensing	SG-U	3.225%	9,806,011	26,376	(14,920)	9,791,091	26,336	(14,920)	9,776,170	26,296	(14,920)	9,761,250	26,256	(14,920)	9,746,329	26,216	-	9,746,329	26,216	
General Office	SO	6.156%	461,592,927	2,368,714	3,595,362	465,178,289	2,376,952	(475,199)	464,703,089	2,384,954	1,409,031	466,112,120	2,387,349	10,676,514	476,788,634	2,418,346	-	476,788,634	2,418,346	
Utah	UT	-0.148%	(26,170,458)	3,233	(561)	(26,171,019)	3,233	(561)	(26,171,581)	3,233	(561)	(26,172,142)	3,233	(561)	(26,172,704)	3,233	-	(26,172,704)	3,233	
Washington	WA	0.155%	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	
Eastern Wyoming	WYP	1.960%	5,560,780	9,090	(7,729)	5,553,052	9,078	(7,729)	5,545,323	9,065	(7,729)	5,537,594	9,052	(7,729)	5,529,866	9,040	-	5,529,866	9,040	
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Klamath		0.000%	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-	
Total Intangible Plant			1,063,781,685	4,379,477	3,465,835	1,067,247,521	4,387,221	(604,726)	1,066,642,795	4,394,730	1,279,504	1,067,922,300	4,396,632	10,546,987	1,078,469,287	4,427,136	-	1,078,469,287	4,427,136	
<b>Hydro Production Plant:</b>																				
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Post-merger	SG-P	2.126%	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	
Post-merger	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Hydro Plant			14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	
<b>Other Production Plant:</b>																				
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total Other Plant			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
<b>General Plant:</b>																				
California	CA	0.000%	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	
General Office	CN	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Oregon	OR	5.852%	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	
General Office	SO	5.965%	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	
Utah	UT	0.000%	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	
Washington	WA	3.801%	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	
Eastern Wyoming	WYP	1.161%	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total General Plant			14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	
<b>Total Amortization</b>			<b>1,093,426,270</b>	<b>4,453,838</b>	<b>3,465,835</b>	<b>1,096,892,105</b>	<b>4,461,582</b>	<b>(604,726)</b>	<b>1,096,287,379</b>	<b>4,469,091</b>	<b>1,279,504</b>	<b>1,097,566,884</b>	<b>4,470,993</b>	<b>10,546,987</b>	<b>1,108,113,871</b>	<b>4,501,497</b>	<b>-</b>	<b>1,108,113,871</b>	<b>4,501,497</b>	
<b>Total Depreciation &amp; Amortization</b>			<b>32,118,819,612</b>	<b>95,763,748</b>	<b>48,729,458</b>	<b>32,167,549,070</b>	<b>95,841,939</b>	<b>77,450,364</b>	<b>32,244,999,434</b>	<b>95,985,291</b>	<b>94,282,486</b>	<b>32,339,281,921</b>	<b>96,165,769</b>	<b>195,686,811</b>	<b>32,534,968,731</b>	<b>96,561,707</b>	<b>-</b>	<b>32,534,968,731</b>	<b>96,561,707</b>	

PacifiCorp  
Oregon General Rate Case - December 2023  
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Test Period Depreciation Expense
<b>DEPRECIATION EXPENSE</b>			
<b>Steam Production Plant:</b>			
Pre-merger Pacific	SG	6.692%	67,261,085
Pre-merger Utah	SG	5.015%	52,632,126
Post-merger	SG	6.992%	340,167,064
Geothermal - Blundell	SG	6.992%	2,055,827
Carbon	SG		-
Pollution Control Equipment	SG	6.992%	-
Pollution Control Equipment	SG	0.000%	-
Post-merger	SG	0.000%	-
Total Steam Plant			462,116,102
<b>Hydro Production Plant:</b>			
Pre-merger Pacific	SG	2.210%	4,043,093
Pre-merger Utah	SG	3.181%	1,249,428
Post-merger	SG-P	2.741%	19,524,790
Post-merger	SG-U	4.692%	8,599,880
Klamath - New Capital	SG-P	20.000%	1,929,533
Klamath		0.000%	-
Total Hydro Plant			35,346,724
<b>Other Production Plant:</b>			
Pre-merger Utah	SG	0.000%	-
Post-merger	SG	3.503%	68,522,352
Post-merger Wind	SG-W	4.223%	137,093,159
Black Cap Solar	OR	0.000%	-
Post-merger	SG	4.825%	4,322,762
Total Other Plant			209,938,272
<b>Transmission Plant:</b>			
Pre-merger Pacific	SG	1.700%	8,104,707
Pre-merger Utah	SG	1.673%	10,294,566
Post-merger	SG	1.724%	119,830,885
Total Transmission Plant			138,230,148
<b>Distribution Plant:</b>			
California	CA	2.704%	9,254,102
Oregon	OR	2.271%	56,428,045
Washington	WA	2.588%	16,032,588
Eastern Wyoming	WYP	2.685%	19,227,174
Utah	UT	2.540%	93,266,338
Idaho	ID	2.561%	11,380,194
Western Wyoming	WYU	2.682%	4,144,520
Total Distribution Plant			209,732,961
<b>General Plant:</b>			
California	CA	2.021%	474,036
Oregon	OR	2.577%	6,150,304
Washington	WA	2.371%	1,117,620
Eastern Wyoming	WYP	2.539%	2,256,466
Utah	UT	2.215%	6,150,804
Idaho	ID	1.990%	1,092,107
Western Wyoming	WYU	2.182%	384,695
Pre-merger Pacific	SG	2.093%	15,841
Pre-merger Utah	SG	1.231%	27,917
Post-merger	SG	3.438%	10,714,682
General Office	SO	5.656%	22,902,899
General Office	SG	0.000%	-
General Office	SG	3.982%	8,888
Customer Service	CN	5.953%	923,079
Fuel Related	SE	3.632%	110,810
Total General Plant			52,330,149
<b>Mining Plant:</b>			
Coal Mine	SE	0.000%	-
Total Mining Plant			-
<b>Total Depreciation Expense</b>			<b>1,107,694,357</b>

PacifiCorp  
Oregon General Rate Case - December 2023  
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Test Period Depreciation Expense
<b>AMORTIZATION EXPENSE</b>			
<b>Intangible Plant:</b>			
California	CA	0.367%	1,765
Customer Service	CN	6.456%	13,792,251
Pre-merger Utah	SG	2.611%	12,470
Pre-merger Pacific	SG	0.000%	-
Idaho	ID	0.527%	23,033
Oregon	OR	0.254%	11,687
Fuel Related	SE	20.000%	(12,865)
Post-merger	SG	3.402%	7,129,208
Hydro Relicensing	SG-P	2.593%	2,680,267
Hydro Relicensing	SG-U	3.225%	314,346
General Office	SO	6.156%	29,348,751
Utah	UT	-0.148%	38,802
Washington	WA	0.155%	3,148
Eastern Wyoming	WYP	1.960%	108,401
Western Wyoming	WYU	0.000%	-
Klamath		0.000%	-
Total Intangible Plant			53,451,266
<b>Hydro Production Plant:</b>			
Pre-merger Pacific	SG	0.000%	-
Post-merger	SG-P	2.126%	311,696
Post-merger	SG-U	0.000%	-
Total Hydro Plant			311,696
<b>Other Production Plant:</b>			
Post-merger	SG	0.000%	-
Total Other Plant			-
<b>General Plant:</b>			
California	CA	0.000%	-
General Office	CN	0.000%	-
Oregon	OR	5.852%	322,905
General Office	SO	5.965%	108,292
Utah	UT	0.000%	-
Washington	WA	3.801%	96,268
Eastern Wyoming	WYP	1.161%	53,169
Western Wyoming	WYU	0.000%	-
Total General Plant			580,634
<b>Total Amortization</b>			54,343,596
<b>Total Depreciation &amp; Amortization</b>			1,162,037,953
			Ref. 6.1.3
			1,162,037,953

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Depreciation and Amortization Reserve**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Steam Depreciation Reserve	108SP	3	(93,682,972)	SG	26.070%	(24,423,471)	
Steam Depreciation Reserve	108SP	3	(69,456,778)	SG	26.070%	(18,107,620)	
Steam Depreciation Reserve	108SP	3	(1,335,136,315)	SG	26.070%	(348,074,604)	
Steam Depreciation Reserve	108SP	3	-	SG	26.070%	-	
Hydro Depreciation Reserve	108HP	3	23,341,096	SG-P	26.070%	6,085,104	
Hydro Depreciation Reserve	108HP	3	(1,290,381)	SG-U	26.070%	(336,407)	
Hydro Depreciation Reserve	108HP	3	(53,037,520)	SG-P	26.070%	(13,827,063)	
Hydro Depreciation Reserve	108HP	3	(10,810,908)	SG-U	26.070%	(2,818,441)	
Other Depreciation Reserve	108OP	3	-	SG	26.070%	-	
Other Depreciation Reserve	108OP	3	(63,870,472)	SG	26.070%	(16,651,250)	
Other Depreciation Reserve	108OP	3	(199,200,573)	SG-W	26.070%	(51,932,271)	
Other Depreciation Reserve	108OP	3	-	OR	Situs	-	
Other Depreciation Reserve	108OP	3	(5,629,717)	SG	26.070%	(1,467,686)	
Transmission Depreciation Reserve	108TP	3	(9,151,224)	SG	26.070%	(2,385,755)	
Transmission Depreciation Reserve	108TP	3	(10,160,453)	SG	26.070%	(2,648,865)	
Transmission Depreciation Reserve	108TP	3	(154,513,575)	SG	26.070%	(40,282,217)	
Distribution Depreciation Reserve	108360	3	(1,702,246)	OR	Situs	(322,546)	
Distribution Depreciation Reserve	108361	3	(3,226,778)	OR	Situs	(611,418)	
Distribution Depreciation Reserve	108362	3	(26,773,824)	OR	Situs	(5,073,172)	
Distribution Depreciation Reserve	108364	3	(34,990,444)	OR	Situs	(6,630,078)	
Distribution Depreciation Reserve	108365	3	(22,018,252)	OR	Situs	(4,172,074)	
Distribution Depreciation Reserve	108366	3	(10,923,966)	OR	Situs	(2,069,901)	
Distribution Depreciation Reserve	108367	3	(25,483,401)	OR	Situs	(4,828,659)	
Distribution Depreciation Reserve	108368	3	(38,573,422)	OR	Situs	(7,308,990)	
Distribution Depreciation Reserve	108369	3	(23,852,875)	OR	Situs	(4,519,703)	
Distribution Depreciation Reserve	108370	3	(6,529,351)	OR	Situs	(1,237,198)	
Distribution Depreciation Reserve	108371	3	(225,751)	OR	Situs	(42,776)	
Distribution Depreciation Reserve	108373	3	(1,616,725)	OR	Situs	(306,341)	
General Depreciation Reserve	108GP	3	(822,830)	CA	Situs	-	
General Depreciation Reserve	108GP	3	(9,965,858)	OR	Situs	(9,965,858)	
General Depreciation Reserve	108GP	3	(1,079,525)	WA	Situs	-	
General Depreciation Reserve	108GP	3	(1,880,858)	WYP	Situs	-	
General Depreciation Reserve	108GP	3	(9,588,617)	UT	Situs	-	
General Depreciation Reserve	108GP	3	(2,523,222)	ID	Situs	-	
General Depreciation Reserve	108GP	3	(664,947)	WYU	Situs	-	
General Depreciation Reserve	108GP	3	192,685	SG	26.070%	50,234	
General Depreciation Reserve	108GP	3	382,208	SG	26.070%	99,643	
General Depreciation Reserve	108GP	3	(12,094,928)	SG	26.070%	(3,153,189)	
General Depreciation Reserve	108GP	3	(9,553,108)	SO	27.173%	(2,595,874)	
General Depreciation Reserve	108GP	3	-	SG	26.070%	-	
General Depreciation Reserve	108GP	3	(17,612)	SG	26.070%	(4,591)	
General Depreciation Reserve	108GP	3	360,700	CN	30.990%	111,781	
General Depreciation Reserve	108GP	3	43,824	SE	25.068%	10,986	
Mining Depreciation Reserve	108MP	3	-	SE	25.068%	-	
			<u>(2,225,728,915)</u>			<u>(569,440,273)</u>	6.2.2

**Description of Adjustment:**

This adjustment steps forward the depreciation reserve to a December 2022 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2021 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2021 to December 31, 2022. An incremental amount has been added to the December 31, 2022 balance to reflect the annualized depreciation expense in adjustment 6.1.



**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Depreciation and Amortization Reserve**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Intangible Amortization Reserve	111IP	3	(2,648)	CA	Situs	-	
Intangible Amortization Reserve	111IP	3	(20,089,447)	CN	30.990%	(6,225,705)	
Intangible Amortization Reserve	111IP	3	(43,567)	ID	Situs	-	
Intangible Amortization Reserve	111IP	3	(31,176)	SG	26.070%	(8,128)	
Intangible Amortization Reserve	111IP	3	(10,998)	OR	Situs	(10,998)	
Intangible Amortization Reserve	111IP	3	86,607	SE	25.068%	21,711	
Intangible Amortization Reserve	111IP	3	(9,577,171)	SG	26.070%	(2,496,801)	
Intangible Amortization Reserve	111IP	3	(3,937,327)	SG-P	26.070%	(1,026,475)	
Intangible Amortization Reserve	111IP	3	(206,561)	SG-U	26.070%	(53,851)	
Intangible Amortization Reserve	111IP	3	(22,536,499)	SO	27.173%	(6,123,861)	
Intangible Amortization Reserve	111IP	3	-	SG	26.070%	-	
Intangible Amortization Reserve	111IP	3	(48,092)	UT	Situs	-	
Intangible Amortization Reserve	111IP	3	(4,722)	WA	Situs	-	
Intangible Amortization Reserve	111IP	3	(24,624)	WYP	Situs	-	
Intangible Amortization Reserve	111IP	3	-	WYU	Situs	-	
Intangible Amortization Reserve	111IP	3	-	SG	26.070%	-	
Hydro Amortization Reserve	111HP	3	-	SG	26.070%	-	
Hydro Amortization Reserve	111HP	3	(467,544)	SG-P	26.070%	(121,890)	
Hydro Amortization Reserve	111HP	3	-	SG-U	26.070%	-	
Other Amortization Reserve	111OP	3	-	SG	26.070%	-	
General Amortization Reserve	111GP	3	-	CA	Situs	-	
General Amortization Reserve	111GP	3	-	CN	30.990%	-	
General Amortization Reserve	111GP	3	-	SG	26.070%	-	
General Amortization Reserve	111GP	3	(484,357)	OR	Situs	(484,357)	
General Amortization Reserve	111GP	3	(162,438)	SO	27.173%	(44,139)	
General Amortization Reserve	111GP	3	-	UT	Situs	-	
General Amortization Reserve	111GP	3	(144,403)	WA	Situs	-	
General Amortization Reserve	111GP	3	(79,754)	WYP	Situs	-	
General Amortization Reserve	111GP	3	-	WYU	Situs	-	
			<u>(57,764,719)</u>			<u>(16,574,495)</u>	6.2.3
Total Adjustment			<u>(2,283,493,634)</u>			<u>(586,014,768)</u>	

**Description of Adjustment:**

This adjustment steps forward the depreciation reserve to a December 2022 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2021 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2021 to December 31, 2022.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Depreciation and Amortization Reserve Summary**

<u>Description</u>	<u>Account</u>	<u>Factor</u>	<u>12 ME Jun 2021 Reserve</u>	<u>Test Period Reserve</u>	<u>Adjustment to Test Period</u>
<b>DEPRECIATION RESERVE</b>					
<b>Steam Production Plant:</b>					
Pre-merger Pacific	108SP	SG	(749,221,847)	(842,904,819)	(93,682,972)
Pre-merger Utah	108SP	SG	(719,880,716)	(789,337,495)	(69,456,778)
Post-merger	108SP	SG	(1,901,219,938)	(3,236,356,253)	(1,335,136,315)
Post-merger	108SP	SG	-	-	-
Total Steam Plant			<u>(3,370,322,501)</u>	<u>(4,868,598,566)</u>	<u>(1,498,276,065)</u>
<b>Hydro Production Plant:</b>					
Pre-merger Pacific	108HP	SG-P	(169,356,335)	(146,015,239)	23,341,096
Pre-merger Utah	108HP	SG-U	(31,496,322)	(32,786,703)	(1,290,381)
Post-merger	108HP	SG-P	(233,526,380)	(286,563,901)	(53,037,520)
Post-merger	108HP	SG-U	(62,385,722)	(73,196,630)	(10,810,908)
Total Hydro Plant			<u>(496,764,760)</u>	<u>(538,562,473)</u>	<u>(41,797,713)</u>
<b>Other Production Plant:</b>					
Pre-merger Utah	108OP	SG	-	-	-
Post-merger	108OP	SG	(482,707,852)	(546,578,324)	(63,870,472)
Post-merger - Wind	108OP	SG-W	383,543,335	184,342,762	(199,200,573)
Black Cap Solar	108OP	OR	-	-	-
Post-merger	108OP	SG	(43,837,829)	(49,467,546)	(5,629,717)
Total Other Plant			<u>(143,002,346)</u>	<u>(411,703,108)</u>	<u>(268,700,761)</u>
<b>Transmission Plant:</b>					
Pre-merger Pacific	108TP	SG	(353,157,214)	(362,308,437)	(9,151,224)
Pre-merger Utah	108TP	SG	(426,788,101)	(436,948,554)	(10,160,453)
Post-merger	108TP	SG	(1,221,447,907)	(1,375,961,482)	(154,513,575)
Total Transmission Plant			<u>(2,001,393,221)</u>	<u>(2,175,218,473)</u>	<u>(173,825,252)</u>
<b>Distribution Plant:</b>					
California	108364	CA	(150,707,932)	(160,244,726)	(9,536,795)
Oregon	108364	OR	(1,085,987,789)	(1,123,110,646)	(37,122,857)
Washington	108364	WA	(273,678,015)	(290,502,417)	(16,824,402)
Eastern Wyoming	108364	WYP	(289,764,719)	(308,800,678)	(19,035,960)
Utah	108364	UT	(1,071,716,019)	(1,167,331,507)	(95,615,488)
Idaho	108364	ID	(158,999,969)	(171,059,258)	(12,059,288)
Western Wyoming	108364	WYU	(62,150,629)	(67,872,874)	(5,722,245)
Total Distribution Plant			<u>(3,093,005,071)</u>	<u>(3,288,922,105)</u>	<u>(195,917,035)</u>
<b>General Plant:</b>					
California	108GP	CA	(7,256,531)	(8,079,361)	(822,830)
Oregon	108GP	OR	(98,593,172)	(108,559,029)	(9,965,858)
Washington	108GP	WA	(24,976,433)	(26,055,958)	(1,079,525)
Eastern Wyoming	108GP	WYP	(27,328,344)	(29,209,202)	(1,880,858)
Utah	108GP	UT	(92,748,344)	(102,336,961)	(9,588,617)
Idaho	108GP	ID	(19,950,503)	(22,473,724)	(2,523,222)
Western Wyoming	108GP	WYU	(6,737,606)	(7,402,553)	(664,947)
Pre-merger Pacific	108GP	SG	(715,242)	(522,557)	192,685
Pre-merger Utah	108GP	SG	(1,951,711)	(1,569,503)	382,208
Post-merger	108GP	SG	(127,433,166)	(139,528,094)	(12,094,928)
General Office	108GP	SO	(116,526,662)	(126,079,770)	(9,553,108)
General Office	108GP	SG	-	-	-
General Office	108GP	SG	(130,406)	(148,018)	(17,612)
Customer Service	108GP	CN	(7,270,206)	(6,909,506)	360,700
Fuel Related	108GP	SE	(1,538,215)	(1,494,391)	43,824
Total General Plant			<u>(533,156,539)</u>	<u>(580,368,628)</u>	<u>(47,212,089)</u>
<b>Mining Plant:</b>					
Coal Mine	108MP	SE	-	-	-
Total Mining Plant			<u>-</u>	<u>-</u>	<u>-</u>
<b>Total Depreciation Reserve</b>			<u>(9,637,644,438)</u>	<u>(11,863,373,353)</u>	<u>(2,225,728,915)</u>

Ref 6.2

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Depreciation and Amortization Reserve Summary**

<u>Description</u>	<u>Account</u>	<u>Factor</u>	<u>12 ME Jun 2021 Reserve</u>	<u>Test Period Reserve</u>	<u>Adjustment to Test Period</u>
<b>AMORTIZATION RESERVE</b>					
<b>Intangible Plant:</b>					
California	111IP	CA	(6,202)	(8,850)	(2,648)
Customer Service	111IP	CN	(162,639,670)	(182,729,117)	(20,089,447)
Idaho	111IP	ID	(976,939)	(1,020,506)	(43,567)
Pre-merger Utah	111IP	SG	(397,058)	(428,234)	(31,176)
Oregon	111IP	OR	(129,177)	(140,175)	(10,998)
Fuel Related	111IP	SE	(1,897)	84,709	86,607
Post-merger	111IP	SG	(105,977,548)	(115,554,719)	(9,577,171)
Hydro Relicensing	111IP	SG-P	(114,544,697)	(118,482,024)	(3,937,327)
Hydro Relicensing	111IP	SG-U	(5,755,401)	(5,961,962)	(206,561)
General Office	111IP	SO	(316,598,295)	(339,134,793)	(22,536,499)
Pre-merger Pacific	111IP	SG	-	-	-
Utah	111IP	UT	31,976,724	31,928,632	(48,092)
Washington	111IP	WA	(10,692)	(15,414)	(4,722)
Eastern Wyoming	111IP	WYP	(375,132)	(399,756)	(24,624)
Western Wyoming	111IP	WYU	-	-	-
General Office	111IP	SG	-	-	-
Total Intangible Plant			<u>(675,435,985)</u>	<u>(731,862,209)</u>	<u>(56,426,225)</u>
<b>Hydro Production Plant:</b>					
Pre-merger Pacific	111HP	SG	-	-	-
Post-merger	111HP	SG-P	(3,139,235)	(3,606,778)	(467,544)
Post-merger	111HP	SG-U	-	-	-
Total Hydro Plant			<u>(3,139,235)</u>	<u>(3,606,778)</u>	<u>(467,544)</u>
<b>Other Production Plant:</b>					
Post-merger	111OP	SG	-	-	-
Total Other Plant			<u>-</u>	<u>-</u>	<u>-</u>
<b>General Plant:</b>					
California	111GP	CA	(505,860)	(505,860)	-
General Office	111GP	CN	-	-	-
Idaho	111GP	ID	(333,771)	(333,771)	-
Oregon	111GP	OR	(4,741,005)	(5,225,362)	(484,357)
General Office	111GP	SO	(1,174,857)	(1,337,295)	(162,438)
Utah	111GP	UT	(33,127)	(33,127)	-
Washington	111GP	WA	(1,855,482)	(1,999,885)	(144,403)
Eastern Wyoming	111GP	WYP	(4,454,478)	(4,534,231)	(79,754)
Western Wyoming	111GP	WYU	-	-	-
Total General Plant			<u>(13,098,578)</u>	<u>(13,969,530)</u>	<u>(870,951)</u>
<b>Total Amortization Reserve</b>			<u>(691,673,798)</u>	<u>(749,438,517)</u>	<u>(57,764,719)</u>
					<b>Ref 6.2.1</b>
<b>Total Depreciation &amp; Amortization Reserve</b>			<u>(10,329,318,236)</u>	<u>(12,612,811,871)</u>	<u>(2,283,493,634)</u>
				<b>Ref. 6.2.9</b>	

PacifiCorp  
Oregon General Rate Case - December 2023  
Jun 2021 - December 2022 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jun 2021		Adjusted Reserve Balance Jul 2021		Adjusted Reserve Balance Aug 2021		Adjusted Reserve Balance Sep 2021		Adjusted Reserve Balance Oct 2021		Adjusted Reserve Balance Nov 2021		Adjusted Reserve Balance Dec 2021	
			Adjustments		Adjustments		Adjustments		Adjustments		Adjustments		Adjustments		Adjustments
<b>DEPRECIATION RESERVE</b>															
<b>Steam Production Plant:</b>															
Pre-merger Pacific	SG	(749,221,847)	(5,233,328)	(754,455,175)	(5,231,030)	(759,686,205)	(5,228,733)	(764,914,938)	(5,226,435)	(770,141,373)	(5,224,138)	(775,365,511)	(5,221,840)	(780,587,352)	(5,219,543)
Pre-merger Utah	SG	(719,880,716)	(3,886,844)	(723,767,560)	(3,884,593)	(727,652,154)	(3,882,343)	(731,534,497)	(3,880,092)	(735,414,588)	(3,877,841)	(739,292,430)	(3,875,590)	(743,168,020)	(3,873,340)
Post-merger	SG	(2,794,088,362)	(23,499,216)	(2,817,587,578)	(23,492,813)	(2,841,080,391)	(23,492,780)	(2,864,563,171)	(23,506,336)	(2,888,069,507)	(23,536,757)	(2,911,606,264)	(23,559,421)	(2,935,165,685)	(23,572,366)
Geothermal - Blundell	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Carbon	SG	(10,240,252)	(171,319)	(10,411,571)	(171,319)	(10,582,890)	(171,319)	(10,754,209)	(171,319)	(10,925,528)	(171,319)	(11,096,847)	(171,319)	(11,268,165)	(171,319)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total Steam Plant</b>		<b>(4,273,431,177)</b>	<b>(32,790,706)</b>	<b>(4,306,221,884)</b>	<b>(32,779,756)</b>	<b>(4,339,001,640)</b>	<b>(32,765,174)</b>	<b>(4,371,766,814)</b>	<b>(32,764,183)</b>	<b>(4,404,550,997)</b>	<b>(32,810,055)</b>	<b>(4,437,361,052)</b>	<b>(32,828,170)</b>	<b>(4,470,189,222)</b>	<b>(32,836,568)</b>
<b>Hydro Production Plant:</b>															
Pre-merger Pacific	SG	(140,844,465)	(288,419)	(141,132,884)	(288,327)	(141,421,211)	(288,235)	(141,709,446)	(288,142)	(141,997,588)	(288,050)	(142,285,638)	(287,958)	(142,573,595)	(287,865)
Pre-merger Utah	SG	(31,496,322)	(72,777)	(31,569,099)	(72,690)	(31,641,789)	(72,603)	(31,714,392)	(72,516)	(31,786,908)	(72,428)	(31,859,336)	(72,341)	(31,931,677)	(72,254)
Post-merger	SG-P	(168,283,208)	(1,117,512)	(169,400,720)	(1,116,763)	(170,517,483)	(1,117,835)	(171,635,318)	(1,121,109)	(172,756,426)	(1,127,316)	(173,883,742)	(1,146,750)	(175,030,402)	(1,161,854)
Post-merger	SG-U	(62,385,722)	(519,924)	(63,905,646)	(520,048)	(65,426,894)	(520,809)	(66,946,503)	(522,225)	(68,468,278)	(525,314)	(69,994,042)	(541,568)	(71,538,612)	(554,980)
Klamath - New Capital	SG-P	(324,034)	(45,065)	(369,098)	(45,065)	(414,163)	(47,406)	(461,569)	(50,359)	(511,128)	(60,244)	(572,173)	(69,519)	(641,682)	(69,519)
Klamath	SG	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-
<b>Total Hydro Plant</b>		<b>(496,764,760)</b>	<b>(2,043,697)</b>	<b>(498,808,457)</b>	<b>(2,042,892)</b>	<b>(500,851,349)</b>	<b>(2,046,888)</b>	<b>(502,896,237)</b>	<b>(2,054,350)</b>	<b>(504,952,587)</b>	<b>(2,073,353)</b>	<b>(507,025,940)</b>	<b>(2,118,136)</b>	<b>(509,144,076)</b>	<b>(2,146,472)</b>
<b>Other Production Plant:</b>															
Pre-merger Utah	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(482,707,852)	(3,480,877)	(486,188,729)	(3,474,950)	(489,663,679)	(3,469,005)	(493,132,684)	(3,504,630)	(496,637,314)	(3,540,846)	(500,178,160)	(3,536,023)	(503,714,183)	(3,530,719)
Post-merger Wind	SG-W	383,543,335	(10,862,430)	372,680,905	(10,926,631)	361,754,273	(10,968,287)	350,795,986	(11,011,743)	339,784,243	(11,050,540)	328,733,703	(11,062,197)	317,671,506	(11,069,966)
Black Cap Solar	OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(43,837,829)	(300,707)	(44,138,536)	(303,183)	(44,441,720)	(309,649)	(44,751,369)	(316,114)	(45,067,482)	(315,956)	(45,383,438)	(315,797)	(45,699,235)	(315,633)
<b>Total Other Plant</b>		<b>(143,002,346)</b>	<b>(14,644,015)</b>	<b>(157,646,361)</b>	<b>(14,704,765)</b>	<b>(172,351,126)</b>	<b>(14,736,941)</b>	<b>(187,088,067)</b>	<b>(14,832,487)</b>	<b>(201,920,554)</b>	<b>(14,907,341)</b>	<b>(216,827,895)</b>	<b>(14,914,017)</b>	<b>(231,741,912)</b>	<b>(14,916,318)</b>
<b>Transmission Plant:</b>															
Pre-merger Pacific	SG	(353,157,214)	(511,379)	(353,668,593)	(511,141)	(354,179,734)	(510,903)	(354,690,637)	(510,665)	(355,201,301)	(510,426)	(355,711,728)	(510,188)	(356,221,916)	(509,950)
Pre-merger Utah	SG	(426,788,101)	(569,619)	(427,357,719)	(569,207)	(427,926,926)	(568,795)	(428,496,721)	(568,383)	(429,066,104)	(567,971)	(429,636,075)	(567,559)	(430,199,634)	(567,147)
Post-merger	SG	(1,221,447,907)	(8,178,932)	(1,229,626,839)	(8,185,870)	(1,237,812,709)	(8,198,049)	(1,246,010,758)	(8,239,158)	(1,254,249,916)	(8,296,866)	(1,262,546,782)	(8,353,538)	(1,270,900,321)	(8,383,048)
<b>Total Transmission Plant</b>		<b>(2,001,393,221)</b>	<b>(9,259,930)</b>	<b>(2,010,653,151)</b>	<b>(9,266,218)</b>	<b>(2,019,919,369)</b>	<b>(9,277,747)</b>	<b>(2,029,197,116)</b>	<b>(9,318,205)</b>	<b>(2,038,515,321)</b>	<b>(9,375,264)</b>	<b>(2,047,890,585)</b>	<b>(9,431,286)</b>	<b>(2,057,321,871)</b>	<b>(9,460,145)</b>
<b>Distribution Plant:</b>															
California	CA	(150,707,932)	(448,820)	(151,156,751)	(449,823)	(151,606,574)	(451,902)	(152,056,476)	(454,722)	(152,513,198)	(458,652)	(152,981,850)	(462,591)	(153,464,441)	(466,520)
Oregon	OR	(1,085,987,789)	(1,852,942)	(1,087,840,731)	(1,859,727)	(1,089,700,458)	(1,877,531)	(1,091,577,989)	(1,895,690)	(1,093,473,678)	(1,912,266)	(1,095,375,944)	(1,931,221)	(1,097,289,166)	(1,922,914)
Washington	WA	(273,678,015)	(864,656)	(274,542,671)	(868,009)	(275,410,680)	(870,883)	(276,281,563)	(873,412)	(277,154,975)	(875,227)	(278,030,202)	(877,312)	(278,907,515)	(879,411)
Eastern Wyoming	WYP	(289,764,719)	(989,340)	(290,754,059)	(993,097)	(291,747,156)	(997,161)	(292,744,317)	(1,002,049)	(293,746,365)	(1,006,472)	(294,752,837)	(1,023,466)	(295,776,303)	(1,039,721)
Utah	UT	(1,071,716,019)	(4,830,716)	(1,076,546,735)	(4,852,741)	(1,081,399,476)	(4,884,403)	(1,086,289,879)	(4,930,997)	(1,091,214,876)	(4,964,686)	(1,096,179,561)	(4,999,599)	(1,101,179,161)	(5,035,006)
Idaho	ID	(158,999,969)	(600,219)	(159,600,189)	(602,170)	(160,202,359)	(605,658)	(160,808,017)	(611,833)	(161,419,850)	(623,402)	(162,043,252)	(634,072)	(162,677,324)	(639,520)
Western Wyoming	WYU	(62,150,629)	(318,679)	(62,469,308)	(318,617)	(62,787,924)	(318,554)	(63,106,479)	(318,492)	(63,424,971)	(318,430)	(63,743,401)	(318,368)	(64,067,769)	(318,306)
<b>Total Distribution Plant</b>		<b>(3,093,005,071)</b>	<b>(9,905,372)</b>	<b>(3,102,910,442)</b>	<b>(9,944,184)</b>	<b>(3,112,854,627)</b>	<b>(10,006,092)</b>	<b>(3,122,860,719)</b>	<b>(10,087,195)</b>	<b>(3,132,947,914)</b>	<b>(10,159,135)</b>	<b>(3,143,107,049)</b>	<b>(10,248,630)</b>	<b>(3,153,355,679)</b>	<b>(10,319,854)</b>
<b>General Plant:</b>															
California	CA	(7,256,531)	(44,765)	(7,301,296)	(44,714)	(7,346,010)	(44,733)	(7,390,684)	(44,675)	(7,435,359)	(44,671)	(7,480,030)	(44,613)	(7,524,643)	(44,605)
Oregon	OR	(98,593,172)	(524,682)	(99,117,853)	(524,315)	(99,642,168)	(524,798)	(100,166,967)	(526,686)	(100,693,653)	(528,793)	(101,222,446)	(537,369)	(101,759,815)	(545,320)
Washington	WA	(24,976,433)	(58,825)	(25,035,258)	(58,612)	(25,093,869)	(58,687)	(25,152,556)	(58,955)	(25,211,511)	(59,061)	(25,270,572)	(59,162)	(25,329,734)	(59,225)
Eastern Wyoming	WYP	(27,328,344)	(92,732)	(27,421,076)	(92,445)	(27,512,063)	(92,768)	(27,606,289)	(93,645)	(27,699,934)	(94,411)	(27,794,345)	(97,596)	(27,891,941)	(100,834)
Utah	UT	(92,748,344)	(480,911)	(93,229,255)	(482,809)	(93,712,063)	(485,314)	(94,197,377)	(488,490)	(94,685,868)	(493,239)	(95,175,107)	(501,959)	(95,681,066)	(510,340)
Idaho	ID	(19,950,503)	(136,126)	(20,086,628)	(136,066)	(20,222,694)	(136,126)	(20,358,820)	(136,456)	(20,494,976)	(136,778)	(20,632,154)	(137,992)	(20,770,146)	(139,058)
Western Wyoming	WYU	(6,737,606)	(37,662)	(6,775,268)	(37,605)	(6,812,873)	(37,547)	(6,850,420)	(37,489)	(6,887,909)	(37,432)	(6,925,341)	(37,374)	(6,962,714)	(37,316)
Pre-merger Pacific	SG	(7,152,242)	10,401	(7,162,643)	10,426	(7,173,044)	10,450	(7,183,445)	10,474	(7,193,846)	10,498	(7,204,247)	10,522	(7,214,648)	10,546
Pre-merger Utah	SG	(1,951,711)	20,839	(1,930,872)	20,871	(1,910,031)	20,902	(1,889,199)	20,934	(1,868,366)	20,965	(1,847,527)	20,997	(1,826,688)	21,029
Post-merger	SG	(127,433,166)	(654,015)	(128,087,181)	(653,178)	(128,740,359)	(652,111)	(129,392,471)	(651,487)	(130,043,958)	(650,862)	(130,696,026)	(650,237)	(131,348,100)	(649,612)
General Office	SO	(116,528,662)	(331,334)	(116,859,996)	(330,485)	(117,188,481)	(329,636)	(117,517,013)	(328,787)	(117,844,304)	(327,938)	(118,171,735)	(327,089)	(118,499,266)	(326,240)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(130,406)	(978)	(131,384)	(978)	(132,363)	(978)	(133,341)	(978)	(134,320)	(978)	(135,298)	(978)	(136,277)	(978)
Customer Service	CN	(7,270,206)	13,873	(7,256,333)	14,366	(7,241,966)	14,860	(7,227,107)	15,353	(7,212,754)	15,846	(7,198,301)	16,339	(7,183,848)	16,833
Fuel Related	SE	(1,538,215)	1,871	(1,536,344)	1,916	(1,534,428)	1,961	(1,532,467)	2,006	(1,530,460)	2,051	(1,528,409)	2,096	(1,526,313)	2,142
<b>Total General Plant</b>		<b>(533,156,539)</b>	<b>(2,315,045)</b>	<b>(535,471,584)</b>	<b>(2,313,628)</b>	<b>(537,785,212)</b>	<b>(2,327,363)</b>	<b>(540,112,575)</b>	<b>(2,339,422)</b>	<b>(542,511,997)</b>	<b>(2,476,565)</b>	<b>(544,988,562)</b>	<b>(2,535,649)</b>	<b>(547,524,211)</b>	<b>(2,578,788)</b>
<b>Mining Plant:</b>															
Coal Mine	SE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total Mining Plant</b>		<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
<b>Total Depreciation Reserve</b>		<b>(10,540,753,115)</b>	<b>(70,958,765)</b>	<b>(10,611,711,879)</b>	<b>(71,051,443)</b>	<b>(10,682,763,323)</b>	<b>(71,160,205)</b>	<b>(10,753,923,528)</b>	<b>(71,475,842)</b>	<b>(10,825,399,370)</b>	<b>(71,801,712)</b>	<b>(10,897,201,082)</b>	<b>(72,075,889)</b>	<b>(10,969,276,971)</b>	<b>(72,257,925)</b>

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Description	Factor	Adjusted Reserve Balance Jun 2021		Adjusted Reserve Balance Jul 2021		Adjusted Reserve Balance Aug 2021		Adjusted Reserve Balance Sep 2021		Adjusted Reserve Balance Oct 2021		Adjusted Reserve Balance Nov 2021		Adjusted Reserve Balance Dec 2021	
		Reserve Balance	Adjustments	Reserve Balance	Adjustments	Reserve Balance	Adjustments	Reserve Balance	Adjustments	Reserve Balance	Adjustments	Reserve Balance	Adjustments	Reserve Balance	Adjustments
<b>AMORTIZATION RESERVE</b>															
<b>Intangible Plant:</b>															
California	CA	(6,202)	(147)	(6,350)	(147)	(6,497)	(147)	(6,644)	(147)	(6,791)	(147)	(6,938)	(147)	(7,085)	(147)
Customer Service	CN	(162,639,670)	(1,118,380)	(163,758,050)	(1,118,196)	(164,876,246)	(1,118,012)	(165,994,258)	(1,117,828)	(167,112,096)	(1,117,644)	(168,229,730)	(1,117,460)	(169,347,190)	(1,117,276)
Idaho	ID	(978,939)	(1,834)	(978,773)	(1,834)	(980,607)	(1,834)	(982,440)	(1,834)	(984,274)	(1,834)	(986,108)	(1,834)	(987,942)	(1,834)
Pre-merger Utah	SG	(397,058)	(1,039)	(398,098)	(1,039)	(399,137)	(1,039)	(400,176)	(1,039)	(401,215)	(1,039)	(402,254)	(1,039)	(403,294)	(1,039)
Montana	MT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(129,177)	(612)	(129,789)	(612)	(130,400)	(612)	(131,012)	(612)	(131,624)	(612)	(132,236)	(612)	(132,847)	(612)
Fuel Related	SE	(1,897)	3,962	2,064	4,030	6,094	4,098	10,191	4,166	14,357	4,234	18,591	4,302	22,892	4,370
Post-merger	SG	(105,977,548)	(534,295)	(106,511,843)	(534,117)	(107,045,960)	(533,938)	(107,579,898)	(533,760)	(108,113,658)	(533,582)	(108,647,240)	(533,403)	(109,180,643)	(533,225)
Hydro Relicensing	SG-P	(40,432,947)	(218,866)	(40,651,813)	(218,856)	(40,870,670)	(218,846)	(41,089,516)	(218,836)	(41,308,352)	(218,826)	(41,527,178)	(218,816)	(41,745,994)	(218,806)
Hydro Relicensing	SG-U	(5,755,401)	(11,977)	(5,767,378)	(11,937)	(5,779,315)	(11,897)	(5,791,212)	(11,857)	(5,803,068)	(11,816)	(5,814,885)	(11,776)	(5,826,661)	(11,736)
General Office	SO	(316,598,295)	(1,096,611)	(317,694,906)	(1,095,211)	(318,790,117)	(1,093,336)	(319,885,453)	(1,101,264)	(320,986,716)	(1,112,719)	(322,108,436)	(1,121,719)	(323,262,994)	(1,131,719)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	UT	31,976,724	(2,671)	31,974,053	(2,671)	31,971,382	(2,671)	31,968,711	(2,671)	31,966,040	(2,671)	31,963,369	(2,671)	31,960,697	(2,671)
Washington	WA	(10,692)	(262)	(10,954)	(262)	(11,216)	(262)	(11,479)	(262)	(11,741)	(262)	(12,003)	(262)	(12,266)	(262)
Eastern Wyoming	WYP	(375,132)	(1,526)	(376,658)	(1,513)	(378,171)	(1,501)	(379,672)	(1,488)	(381,160)	(1,475)	(382,635)	(1,463)	(384,098)	(1,450)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-
Total Intangible Plant	-	(675,435,985)	(2,984,259)	(678,420,244)	(2,982,366)	(681,402,609)	(2,981,997)	(684,384,607)	(2,987,432)	(687,372,039)	(3,007,394)	(690,379,433)	(3,039,740)	(693,419,173)	(3,060,269)
<b>Hydro Production Plant:</b>															
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(3,139,235)	(25,975)	(3,165,210)	(25,975)	(3,191,184)	(25,975)	(3,217,159)	(25,975)	(3,243,133)	(25,975)	(3,269,108)	(25,975)	(3,295,083)	(25,975)
Post-merger	SG-U	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant	-	(3,139,235)	(25,975)	(3,165,210)	(25,975)	(3,191,184)	(25,975)	(3,217,159)	(25,975)	(3,243,133)	(25,975)	(3,269,108)	(25,975)	(3,295,083)	(25,975)
<b>Other Production Plant:</b>															
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>General Plant:</b>															
California	CA	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-
General Office	CN	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	ID	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-
Oregon	OR	(4,741,005)	(26,909)	(4,767,913)	(26,909)	(4,794,822)	(26,909)	(4,821,731)	(26,909)	(4,848,640)	(26,909)	(4,875,548)	(26,909)	(4,902,457)	(26,909)
General Office	SO	(1,174,857)	(9,024)	(1,183,881)	(9,024)	(1,192,905)	(9,024)	(1,201,930)	(9,024)	(1,210,954)	(9,024)	(1,219,978)	(9,024)	(1,229,003)	(9,024)
Utah	UT	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-
Washington	WA	(1,855,482)	(8,022)	(1,863,504)	(8,022)	(1,871,527)	(8,022)	(1,879,549)	(8,022)	(1,887,572)	(8,022)	(1,895,594)	(8,022)	(1,903,616)	(8,022)
Eastern Wyoming	WYP	(4,454,478)	(4,431)	(4,458,908)	(4,431)	(4,463,339)	(4,431)	(4,467,770)	(4,431)	(4,472,201)	(4,431)	(4,476,632)	(4,431)	(4,481,062)	(4,431)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant	-	(13,098,578)	(48,386)	(13,146,965)	(48,386)	(13,195,351)	(48,386)	(13,243,737)	(48,386)	(13,292,123)	(48,386)	(13,340,509)	(48,386)	(13,388,895)	(48,386)
<b>Total Amortization Reserve</b>	-	<b>(691,673,798)</b>	<b>(3,058,620)</b>	<b>(694,732,418)</b>	<b>(3,056,727)</b>	<b>(697,789,144)</b>	<b>(3,056,358)</b>	<b>(700,845,503)</b>	<b>(3,061,793)</b>	<b>(703,907,295)</b>	<b>(3,081,755)</b>	<b>(706,989,051)</b>	<b>(3,114,101)</b>	<b>(710,103,152)</b>	<b>(3,134,630)</b>
<b>Total Depreciation &amp; Amortization Reserve</b>	-	<b>(11,232,426,913)</b>	<b>(74,017,384)</b>	<b>(11,306,444,297)</b>	<b>(74,108,170)</b>	<b>(11,380,552,467)</b>	<b>(74,216,563)</b>	<b>(11,454,769,030)</b>	<b>(74,537,635)</b>	<b>(11,529,306,666)</b>	<b>(74,883,467)</b>	<b>(11,604,190,133)</b>	<b>(75,189,990)</b>	<b>(11,679,380,123)</b>	<b>(75,392,556)</b>

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Description	Factor	Adjusted Reserve Balance Jan 2022	Adjustments	Adjusted Reserve Balance Feb 2022	Adjustments	Adjusted Reserve Balance Mar 2022	Adjustments	Adjusted Reserve Balance Apr 2022	Adjustments	Adjusted Reserve Balance May 2022	Adjustments	Adjusted Reserve Balance Jun 2022	Adjustments	Adjusted Reserve Balance Jul 2022	Adjustments
<b>DEPRECIATION RESERVE</b>															
<b>Steam Production Plant:</b>															
Pre-merger Pacific	SG	(785,806,895)	(5,217,246)	(791,024,140)	(5,214,948)	(796,239,088)	(5,212,651)	(801,451,739)	(5,210,353)	(806,662,092)	(5,208,056)	(811,870,148)	(5,205,758)	(817,075,906)	(5,203,461)
Pre-merger Utah	SG	(747,041,360)	(3,871,089)	(750,912,449)	(3,868,838)	(754,781,287)	(3,866,587)	(758,647,874)	(3,864,337)	(762,512,211)	(3,862,086)	(766,374,297)	(3,859,835)	(770,234,133)	(3,857,585)
Post-merger	SG	(2,958,738,051)	(23,551,739)	(2,982,289,790)	(23,533,035)	(3,005,822,825)	(23,583,831)	(3,029,406,656)	(23,739,999)	(3,053,146,625)	(23,869,336)	(3,077,015,961)	(23,910,286)	(3,100,926,247)	(23,908,451)
Geothermal - Blundell	SG	(11,439,484)	(171,319)	(11,610,803)	(171,319)	(11,782,122)	(171,319)	(11,953,441)	(171,319)	(12,124,760)	(171,319)	(12,296,079)	(171,319)	(12,467,398)	(171,319)
Carbon	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total Steam Plant</b>		<b>(4,503,025,790)</b>	<b>(32,811,393)</b>	<b>(4,535,837,182)</b>	<b>(32,788,140)</b>	<b>(4,568,625,323)</b>	<b>(32,834,388)</b>	<b>(4,601,459,711)</b>	<b>(32,985,978)</b>	<b>(4,634,445,689)</b>	<b>(33,110,797)</b>	<b>(4,667,556,485)</b>	<b>(33,147,199)</b>	<b>(4,700,703,684)</b>	<b>(33,140,815)</b>
<b>Hydro Production Plant:</b>															
Pre-merger Pacific	SG	(142,861,461)	(287,773)	(143,149,234)	(287,681)	(143,436,914)	(287,588)	(143,724,503)	(287,496)	(144,011,999)	(287,404)	(144,299,402)	(287,311)	(144,586,714)	(287,219)
Pre-merger Utah	SG	(32,003,932)	(72,167)	(32,076,099)	(72,080)	(32,148,179)	(71,993)	(32,220,171)	(71,906)	(32,292,077)	(71,819)	(32,363,896)	(71,731)	(32,435,627)	(71,644)
Post-merger	SG-P	(176,192,346)	(1,164,749)	(177,357,095)	(1,169,163)	(178,526,257)	(1,170,741)	(179,696,998)	(1,171,836)	(180,868,634)	(1,185,695)	(182,054,329)	(1,199,297)	(183,253,626)	(1,207,564)
Post-merger	SG-U	(66,090,590)	(554,582)	(66,645,172)	(554,185)	(67,199,357)	(553,788)	(67,753,145)	(553,391)	(68,306,536)	(553,129)	(68,859,665)	(553,267)	(69,414,932)	(552,989)
Klamath - New Capital	SG-P	(7,111,211)	(69,519)	(7,180,729)	(69,519)	(7,250,248)	(69,519)	(7,319,767)	(69,519)	(7,389,286)	(69,519)	(7,458,805)	(69,519)	(7,528,324)	(69,519)
Klamath	SG	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-
<b>Total Hydro Plant</b>		<b>(511,290,548)</b>	<b>(2,148,790)</b>	<b>(513,439,338)</b>	<b>(2,152,627)</b>	<b>(515,591,965)</b>	<b>(2,153,629)</b>	<b>(517,745,594)</b>	<b>(2,153,947)</b>	<b>(519,899,541)</b>	<b>(2,167,565)</b>	<b>(522,067,106)</b>	<b>(2,183,126)</b>	<b>(524,250,232)</b>	<b>(2,193,215)</b>
<b>Other Production Plant:</b>															
Pre-merger Utah	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger Wind	SG-W	(507,244,902)	(3,524,897)	(510,769,800)	(3,518,675)	(514,288,275)	(3,546,832)	(517,835,107)	(3,580,186)	(521,415,293)	(3,580,730)	(524,996,023)	(3,576,433)	(528,572,457)	(3,570,777)
Black Cap Solar	OR	306,601,540	(11,073,494)	295,528,047	(11,077,022)	284,451,025	(11,080,549)	273,370,476	(11,084,174)	262,286,302	(11,087,798)	251,198,504	(11,091,326)	240,107,178	(11,094,854)
Post-merger	SG	(46,014,868)	(315,464)	(46,330,332)	(315,294)	(46,645,626)	(315,125)	(46,960,751)	(314,955)	(47,275,706)	(314,831)	(47,590,537)	(314,706)	(47,905,243)	(314,537)
<b>Total Other Plant</b>		<b>(246,658,230)</b>	<b>(14,913,655)</b>	<b>(261,571,885)</b>	<b>(14,910,991)</b>	<b>(276,482,876)</b>	<b>(14,942,506)</b>	<b>(291,425,382)</b>	<b>(14,979,316)</b>	<b>(306,404,697)</b>	<b>(14,983,359)</b>	<b>(321,388,057)</b>	<b>(14,982,466)</b>	<b>(336,370,522)</b>	<b>(14,980,167)</b>
<b>Transmission Plant:</b>															
Pre-merger Pacific	SG	(356,731,866)	(509,712)	(357,241,578)	(509,473)	(357,751,051)	(509,235)	(358,260,286)	(509,997)	(358,769,283)	(508,759)	(359,278,042)	(508,520)	(359,786,562)	(508,282)
Pre-merger Utah	SG	(430,766,781)	(566,735)	(431,333,516)	(566,323)	(431,899,839)	(565,911)	(432,465,751)	(565,499)	(433,031,250)	(565,088)	(433,596,337)	(564,676)	(434,161,013)	(564,264)
Post-merger	SG	(1,279,283,370)	(8,388,183)	(1,287,671,553)	(8,397,049)	(1,296,068,601)	(8,410,722)	(1,304,479,323)	(8,438,948)	(1,312,918,271)	(8,472,711)	(1,321,390,982)	(8,513,809)	(1,329,904,791)	(8,552,884)
<b>Total Transmission Plant</b>		<b>(2,066,762,016)</b>	<b>(9,464,630)</b>	<b>(2,076,246,646)</b>	<b>(9,472,845)</b>	<b>(2,085,719,492)</b>	<b>(9,485,868)</b>	<b>(2,095,205,360)</b>	<b>(9,513,444)</b>	<b>(2,104,718,804)</b>	<b>(9,546,557)</b>	<b>(2,114,265,361)</b>	<b>(9,587,005)</b>	<b>(2,123,852,366)</b>	<b>(9,625,430)</b>
<b>Distribution Plant:</b>															
California	CA	(153,949,215)	(487,112)	(154,436,326)	(492,724)	(154,929,050)	(498,155)	(155,427,205)	(503,589)	(155,932,793)	(509,164)	(156,439,258)	(514,800)	(156,954,907)	(520,435)
Oregon	OR	(1,099,212,079)	(1,926,249)	(1,101,138,328)	(1,940,927)	(1,103,079,255)	(1,958,923)	(1,105,038,178)	(1,989,999)	(1,107,028,177)	(2,033,748)	(1,109,061,925)	(2,061,543)	(1,111,123,468)	(2,077,032)
Washington	WA	(279,786,928)	(881,127)	(280,668,055)	(884,369)	(281,552,424)	(888,709)	(282,441,133)	(893,819)	(283,334,953)	(899,902)	(284,234,855)	(924,081)	(285,158,936)	(939,266)
Eastern Wyoming	WYP	(296,816,024)	(1,042,547)	(297,858,571)	(1,045,621)	(298,904,193)	(1,049,125)	(299,953,318)	(1,053,572)	(301,006,890)	(1,058,341)	(302,065,232)	(1,063,115)	(303,127,746)	(1,068,078)
Utah	UT	(1,106,214,167)	(5,061,959)	(1,111,276,126)	(5,101,136)	(1,116,377,262)	(5,141,676)	(1,121,518,938)	(5,194,580)	(1,126,713,518)	(5,251,606)	(1,131,965,124)	(5,299,147)	(1,137,265,271)	(5,324,088)
Idaho	ID	(163,316,844)	(644,030)	(163,960,874)	(648,820)	(164,609,694)	(653,919)	(165,263,613)	(659,394)	(165,923,006)	(664,786)	(166,587,792)	(669,074)	(167,256,866)	(673,393)
Western Wyoming	WYU	(64,380,075)	(318,244)	(64,698,319)	(318,182)	(65,016,501)	(318,120)	(65,334,621)	(318,058)	(65,652,679)	(317,996)	(65,970,674)	(317,934)	(66,288,608)	(317,871)
<b>Total Distribution Plant</b>		<b>(3,163,675,333)</b>	<b>(10,361,267)</b>	<b>(3,174,036,600)</b>	<b>(10,431,780)</b>	<b>(3,184,468,380)</b>	<b>(10,508,626)</b>	<b>(3,194,977,006)</b>	<b>(10,615,011)</b>	<b>(3,205,592,016)</b>	<b>(10,745,842)</b>	<b>(3,216,337,858)</b>	<b>(10,857,944)</b>	<b>(3,227,195,802)</b>	<b>(10,945,371)</b>
<b>General Plant:</b>															
California	CA	(7,569,249)	(44,615)	(7,613,863)	(44,626)	(7,658,489)	(44,629)	(7,703,118)	(44,600)	(7,747,718)	(44,626)	(7,792,344)	(44,720)	(7,837,064)	(45,053)
Oregon	OR	(102,305,135)	(545,450)	(102,850,585)	(545,609)	(103,396,194)	(546,379)	(103,942,573)	(547,575)	(104,490,148)	(549,505)	(105,039,653)	(551,567)	(105,591,220)	(552,873)
Washington	WA	(25,388,959)	(59,146)	(25,448,105)	(59,070)	(25,507,175)	(59,048)	(25,566,223)	(59,043)	(25,625,267)	(59,156)	(25,684,423)	(59,326)	(25,743,748)	(59,382)
Eastern Wyoming	WYP	(27,992,775)	(101,119)	(28,093,894)	(101,111)	(28,195,005)	(101,330)	(28,296,335)	(101,859)	(28,398,194)	(102,686)	(28,500,879)	(103,285)	(28,604,164)	(103,919)
Utah	UT	(96,191,407)	(513,370)	(96,704,776)	(515,898)	(97,220,675)	(518,926)	(97,739,601)	(522,930)	(98,262,531)	(528,049)	(98,790,580)	(533,933)	(99,323,513)	(538,289)
Idaho	ID	(20,909,204)	(139,217)	(21,048,421)	(139,300)	(21,187,721)	(139,395)	(21,327,116)	(139,522)	(21,466,638)	(139,727)	(21,606,365)	(139,921)	(21,746,286)	(140,115)
Western Wyoming	WYU	(7,000,031)	(37,259)	(7,037,289)	(37,201)	(7,074,490)	(37,143)	(7,111,634)	(37,086)	(7,148,719)	(37,028)	(7,185,747)	(36,970)	(7,222,718)	(36,913)
Pre-merger Pacific	SG	(641,923)	10,571	(631,352)	10,595	(620,757)	10,620	(610,137)	10,644	(599,493)	10,668	(588,825)	10,693	(578,132)	10,717
Pre-merger Utah	SG	(1,805,174)	21,060	(1,784,114)	21,092	(1,763,022)	21,123	(1,741,899)	21,155	(1,720,744)	21,186	(1,699,557)	21,218	(1,678,339)	21,250
Post-merger	SG	(132,022,017)	(665,333)	(132,687,351)	(664,490)	(133,351,841)	(663,772)	(134,015,613)	(663,053)	(134,678,666)	(662,272)	(135,340,938)	(661,494)	(136,002,432)	(660,704)
General Office	SG	(119,452,945)	(525,055)	(119,978,000)	(523,527)	(120,501,527)	(522,391)	(121,025,918)	(521,276)	(121,549,196)	(520,160)	(122,074,296)	(519,045)	(122,601,408)	(517,929)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(137,255)	(978)	(138,233)	(978)	(139,212)	(978)	(140,190)	(978)	(141,169)	(978)	(142,147)	(978)	(143,126)	(978)
Customer Service	CN	(7,162,735)	17,326	(7,145,409)	17,819	(7,127,590)	18,312	(7,109,278)	18,806	(7,090,472)	19,299	(7,071,173)	19,792	(7,051,380)	20,286
Fuel Related	SE	(1,524,171)	2,287	(1,521,884)	2,232	(1,519,753)	2,277	(1,517,476)	2,322	(1,515,154)	2,367	(1,512,787)	2,412	(1,510,375)	2,457
<b>Total General Plant</b>		<b>(550,102,979)</b>	<b>(2,580,398)</b>	<b>(552,683,377)</b>	<b>(2,580,072)</b>	<b>(555,263,450)</b>	<b>(2,581,659)</b>	<b>(557,845,109)</b>	<b>(2,588,999)</b>	<b>(560,434,108)</b>	<b>(2,605,607)</b>	<b>(563,039,715)</b>	<b>(2,620,191)</b>	<b>(565,659,905)</b>	<b>(2,625,081)</b>
<b>Mining Plant:</b>															
Coal Mine	SE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total Mining Plant</b>		<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
<b>Total Depreciation Reserve</b>		<b>(11,041,534,897)</b>	<b>(72,280,132)</b>	<b>(11,113,815,029)</b>	<b>(72,336,456)</b>	<b>(11,186,151,485)</b>	<b>(72,506,676)</b>	<b>(11,258,658,161)</b>	<b>(72,836,694)</b>	<b>(11,331,494,855)</b>	<b>(73,159,727)</b>	<b>(11,404,654,582)</b>	<b>(73,377,930)</b>	<b>(11,478,032,512)</b>	<b>(73,510,079)</b>

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Description	Factor	Adjusted Reserve Balance		Adjusted Reserve Balance		Adjusted Reserve Balance		Adjusted Reserve Balance		Adjusted Reserve Balance		Adjusted Reserve Balance		Adjusted Reserve Balance	
		Jan 2022	Adjustments	Feb 2022	Adjustments	Mar 2022	Adjustments	Apr 2022	Adjustments	May 2022	Adjustments	Jun 2022	Adjustments	Jul 2022	Adjustments
<b>AMORTIZATION RESERVE</b>															
<b>Intangible Plant:</b>															
California	CA	(7,232)	(147)	(7,379)	(147)	(7,526)	(147)	(7,673)	(147)	(7,821)	(147)	(7,968)	(147)	(8,115)	(147)
Customer Service	CN	(170,464,466)	(1,117,092)	(171,581,558)	(1,116,908)	(172,698,467)	(1,116,724)	(173,815,191)	(1,116,540)	(174,931,731)	(1,116,356)	(176,048,087)	(1,116,172)	(177,164,260)	(1,115,988)
Idaho	ID	(989,775)	(1,834)	(991,609)	(1,834)	(993,442)	(1,834)	(995,276)	(1,833)	(997,109)	(1,833)	(998,943)	(1,833)	(1,000,776)	(1,833)
Pre-merger Utah	SG	(404,333)	(1,039)	(405,372)	(1,039)	(406,411)	(1,039)	(407,450)	(1,039)	(408,490)	(1,039)	(409,529)	(1,039)	(410,568)	(1,039)
Montana	MT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(133,459)	(611)	(134,070)	(611)	(134,682)	(611)	(135,293)	(611)	(135,904)	(611)	(136,515)	(611)	(137,126)	(611)
Fuel Related	SE	27,262	4,438	31,699	4,506	36,205	4,574	40,778	4,642	45,220	4,710	50,129	4,777	54,907	4,845
Post-merger	SG	(109,713,867)	(533,046)	(110,246,914)	(532,868)	(110,779,782)	(532,689)	(111,312,471)	(532,511)	(111,844,982)	(532,333)	(112,377,315)	(532,154)	(112,909,469)	(531,976)
Hydro Relicensing	SG-P	(41,964,800)	(218,796)	(42,183,596)	(218,786)	(42,402,382)	(218,776)	(42,621,157)	(218,766)	(42,839,923)	(218,756)	(43,058,679)	(218,745)	(43,277,424)	(218,735)
Hydro Relicensing	SG-U	(5,838,397)	(11,696)	(5,850,094)	(11,656)	(5,861,750)	(11,616)	(5,873,366)	(11,576)	(5,884,942)	(11,536)	(5,896,477)	(11,496)	(5,907,973)	(11,456)
General Office	SO	(324,438,575)	(1,181,947)	(325,620,522)	(1,180,992)	(326,801,514)	(1,182,682)	(327,984,196)	(1,183,701)	(329,167,897)	(1,215,934)	(330,383,830)	(1,247,442)	(331,631,272)	(1,245,635)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	UT	31,958,026	(2,671)	31,955,355	(2,671)	31,952,683	(2,672)	31,950,012	(2,672)	31,947,340	(2,672)	31,944,668	(2,672)	31,941,997	(2,672)
Washington	WA	(12,528)	(262)	(12,791)	(262)	(13,053)	(262)	(13,315)	(262)	(13,578)	(262)	(13,840)	(262)	(14,102)	(262)
Eastern Wyoming	WYP	(385,548)	(1,437)	(386,985)	(1,425)	(388,410)	(1,412)	(389,822)	(1,400)	(391,222)	(1,387)	(392,609)	(1,374)	(393,983)	(1,362)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath	SG	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-
Total Intangible Plant		(696,479,443)	(3,066,143)	(699,545,586)	(3,064,694)	(702,610,280)	(3,065,891)	(705,676,171)	(3,066,417)	(708,742,587)	(3,098,156)	(711,840,744)	(3,129,171)	(714,969,915)	(3,126,871)
<b>Hydro Production Plant:</b>															
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(3,321,057)	(25,975)	(3,347,032)	(25,975)	(3,373,007)	(25,975)	(3,398,981)	(25,975)	(3,424,956)	(25,975)	(3,450,931)	(25,975)	(3,476,905)	(25,975)
Post-merger	SG-U	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant		(3,321,057)	(25,975)	(3,347,032)	(25,975)	(3,373,007)	(25,975)	(3,398,981)	(25,975)	(3,424,956)	(25,975)	(3,450,931)	(25,975)	(3,476,905)	(25,975)
<b>Other Production Plant:</b>															
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>General Plant:</b>															
California	CA	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-
General Office	CN	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	ID	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-
Oregon	OR	(4,929,366)	(26,909)	(4,956,275)	(26,909)	(4,983,183)	(26,909)	(5,010,092)	(26,909)	(5,037,001)	(26,909)	(5,063,909)	(26,909)	(5,090,818)	(26,909)
General Office	SO	(1,238,027)	(9,024)	(1,247,051)	(9,024)	(1,256,076)	(9,024)	(1,265,100)	(9,024)	(1,274,124)	(9,024)	(1,283,149)	(9,024)	(1,292,173)	(9,024)
Utah	UT	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-
Washington	WA	(1,911,639)	(8,022)	(1,919,661)	(8,022)	(1,927,683)	(8,022)	(1,935,706)	(8,022)	(1,943,728)	(8,022)	(1,951,750)	(8,022)	(1,959,773)	(8,022)
Eastern Wyoming	WYP	(4,485,493)	(4,431)	(4,489,924)	(4,431)	(4,494,355)	(4,431)	(4,498,785)	(4,431)	(4,503,216)	(4,431)	(4,507,647)	(4,431)	(4,512,078)	(4,431)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant		(13,437,282)	(48,386)	(13,485,668)	(48,386)	(13,534,054)	(48,386)	(13,582,440)	(48,386)	(13,630,826)	(48,386)	(13,679,213)	(48,386)	(13,727,599)	(48,386)
Total Amortization Reserve		(713,237,782)	(3,140,504)	(716,378,286)	(3,139,055)	(719,517,340)	(3,140,252)	(722,657,592)	(3,140,777)	(725,798,370)	(3,172,517)	(728,970,887)	(3,203,532)	(732,174,419)	(3,201,232)
Total Depreciation & Amortization Reserve		(11,754,772,678)	(75,420,636)	(11,830,193,314)	(75,475,511)	(11,905,668,825)	(75,646,928)	(11,981,315,754)	(75,977,471)	(12,057,293,225)	(76,332,244)	(12,133,625,468)	(76,581,462)	(12,210,206,931)	(76,711,311)

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Description	Factor	Adjusted Reserve Balance Aug 2022	Adjustments	Adjusted Reserve Balance Sep 2022	Adjustments	Adjusted Reserve Balance Oct 2022	Adjustments	Adjusted Reserve Balance Nov 2022	Adjustments	Adjusted Reserve Balance Dec 2022	CY 2022 YE Balance	Incremental Reserve For Annualized Depreciation	CY 2022 Adjusted Reserve Year End Balance
<b>DEPRECIATION RESERVE</b>													
<b>Steam Production Plant:</b>													
Pre-merger Pacific	SG	(822,279,367)	(5,201,163)	(827,480,531)	(5,198,866)	(832,679,396)	(5,196,568)	(837,875,965)	(5,194,271)	(843,070,236)	(843,070,236)	165,417	(842,904,819)
Pre-merger Utah	SG	(774,091,717)	(3,855,334)	(777,947,051)	(3,853,063)	(781,800,134)	(3,850,832)	(785,650,966)	(3,848,562)	(789,499,548)	(789,499,548)	162,053	(789,337,495)
Post-merger	SG	(3,124,834,898)	(23,889,756)	(3,148,724,654)	(23,883,911)	(3,172,608,364)	(23,900,401)	(3,196,508,765)	(23,951,446)	(3,220,460,211)	(3,220,460,211)	(2,572,049)	(3,223,032,260)
Geothermal - Blundell	SG	-	-	-	-	-	-	-	-	-	-	-	-
Carbon	SG	(12,638,717)	(171,319)	(12,810,036)	(171,319)	(12,981,355)	(171,319)	(13,152,674)	(171,319)	(13,323,992)	(13,323,992)	-	(13,323,992)
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-
Total Steam Plant		(4,733,844,499)	(33,117,572)	(4,766,962,071)	(33,107,178)	(4,800,069,249)	(33,119,121)	(4,833,188,370)	(33,165,617)	(4,866,353,988)	(4,866,353,988)	(2,244,579)	(4,868,598,566)
<b>Hydro Production Plant:</b>													
Pre-merger Pacific	SG	(144,873,933)	(287,127)	(145,161,060)	(287,034)	(145,448,094)	(286,942)	(145,735,036)	(286,850)	(146,021,886)	(146,021,886)	6,647	(146,015,239)
Pre-merger Utah	SG	(32,507,271)	(71,557)	(32,578,828)	(71,470)	(32,650,298)	(71,383)	(32,721,681)	(71,296)	(32,792,977)	(32,792,977)	6,274	(32,786,703)
Post-merger	SG-P	(184,461,190)	(1,215,818)	(185,677,008)	(1,217,644)	(186,894,652)	(1,225,066)	(188,119,748)	(1,262,600)	(189,382,348)	(189,382,348)	(11,179,319)	(190,561,660)
Post-merger	SG-U	(99,972,201)	(556,872)	(100,529,073)	(563,314)	(101,092,386)	(569,851)	(101,662,237)	(604,083)	(102,266,320)	(102,266,320)	(930,311)	(103,196,630)
Klamath - New Capital	SG-P	(1,197,843)	(69,519)	(1,267,362)	(69,519)	(1,336,880)	(69,534)	(1,406,414)	(144,272)	(1,579,786)	(1,579,786)	(991,438)	(2,571,224)
Klamath	SG	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	(93,431,009)	-	(93,431,009)
Total Hydro Plant		(526,443,447)	(2,200,893)	(528,644,340)	(2,208,981)	(530,853,321)	(2,251,905)	(533,105,226)	(2,369,100)	(535,474,326)	(535,474,326)	(3,088,147)	(538,562,473)
<b>Other Production Plant:</b>													
Pre-merger Utah	SG	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger Utah	SG	(532,143,233)	(3,564,770)	(535,708,003)	(3,562,872)	(539,270,875)	(3,560,974)	(542,831,849)	(3,564,991)	(546,396,841)	(546,396,841)	(181,484)	(546,578,324)
Post-merger Wind	SG-W	229,012,324	(11,098,382)	217,913,942	(11,101,509)	206,812,033	(11,105,437)	195,706,596	(11,108,965)	184,597,631	184,597,631	(254,869)	184,342,762
Black Cap Solar	OR	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(48,219,780)	(314,367)	(48,534,147)	(314,198)	(48,848,345)	(314,028)	(49,162,374)	(313,985)	(49,476,359)	(49,476,359)	8,813	(49,467,546)
Total Other Plant		(351,350,689)	(14,977,519)	(366,328,208)	(14,978,979)	(381,307,187)	(14,980,440)	(396,287,627)	(14,987,941)	(411,275,568)	(411,275,568)	(427,540)	(411,703,108)
<b>Transmission Plant:</b>													
Pre-merger Pacific	SG	(360,294,844)	(508,044)	(360,802,888)	(507,806)	(361,310,694)	(507,567)	(361,818,261)	(507,329)	(362,325,591)	(362,325,591)	17,154	(362,308,437)
Pre-merger Utah	SG	(434,725,277)	(563,822)	(435,289,129)	(563,440)	(435,852,568)	(563,028)	(436,415,596)	(562,616)	(436,978,212)	(436,978,212)	29,658	(436,948,554)
Post-merger	SG	(1,338,457,675)	(8,575,801)	(1,347,033,476)	(8,609,387)	(1,355,642,863)	(8,661,031)	(1,364,303,894)	(8,722,871)	(1,373,026,765)	(1,373,026,765)	(2,934,717)	(1,375,961,482)
Total Transmission Plant		(2,133,477,796)	(9,647,697)	(2,143,125,493)	(9,680,633)	(2,152,806,125)	(9,731,626)	(2,162,537,751)	(9,792,816)	(2,172,330,568)	(2,172,330,568)	(2,887,905)	(2,175,218,473)
<b>Distribution Plant:</b>													
California	CA	(157,523,968)	(540,820)	(158,064,789)	(544,048)	(158,608,837)	(548,233)	(159,157,070)	(557,571)	(159,714,641)	(159,714,641)	(530,085)	(160,244,726)
Oregon	OR	(1,113,200,500)	(2,092,049)	(1,115,292,550)	(2,107,002)	(1,117,399,552)	(2,116,584)	(1,119,516,136)	(2,136,253)	(1,121,652,389)	(1,121,652,389)	(1,458,257)	(1,123,110,646)
Washington	WA	(286,106,003)	(949,960)	(287,055,963)	(952,475)	(288,008,438)	(955,077)	(288,963,515)	(961,266)	(289,924,781)	(289,924,781)	(597,636)	(290,502,417)
Eastern Wyoming	WYP	(304,194,624)	(1,071,359)	(305,265,983)	(1,075,406)	(306,341,389)	(1,079,060)	(307,420,450)	(1,083,085)	(308,503,534)	(308,503,534)	(297,144)	(308,800,678)
Utah	UT	(1,142,579,339)	(5,355,355)	(1,147,934,694)	(5,393,821)	(1,153,328,515)	(5,443,978)	(1,158,772,493)	(5,491,767)	(1,164,264,259)	(1,164,264,259)	(3,067,247)	(1,167,331,507)
Idaho	ID	(167,930,260)	(678,493)	(168,608,753)	(683,641)	(169,292,394)	(687,773)	(169,980,167)	(694,094)	(170,674,261)	(170,674,261)	(384,997)	(171,059,258)
Western Wyoming	WYU	(66,606,479)	(317,809)	(66,924,289)	(317,747)	(67,242,036)	(317,685)	(67,559,721)	(317,623)	(67,877,344)	(67,877,344)	4,471	(67,872,874)
Total Distribution Plant		(3,238,141,173)	(11,005,847)	(3,249,147,020)	(11,074,141)	(3,260,221,161)	(11,148,391)	(3,271,369,552)	(11,241,658)	(3,282,611,210)	(3,282,611,210)	(6,310,896)	(3,288,922,105)
<b>General Plant:</b>													
California	CA	(7,882,117)	(45,403)	(7,927,520)	(45,537)	(7,973,057)	(45,632)	(8,018,689)	(45,949)	(8,064,637)	(8,064,637)	(14,724)	(8,079,361)
Oregon	OR	(106,144,092)	(554,186)	(106,698,279)	(555,757)	(107,254,036)	(557,732)	(107,811,767)	(562,789)	(108,374,556)	(108,374,556)	(184,474)	(108,559,029)
Washington	WA	(25,803,130)	(59,629)	(25,862,759)	(59,898)	(25,922,657)	(59,881)	(25,982,539)	(60,188)	(26,042,727)	(26,042,727)	(13,232)	(26,055,958)
Eastern Wyoming	WYP	(28,708,082)	(104,649)	(28,812,731)	(105,164)	(28,917,895)	(106,395)	(29,024,290)	(108,540)	(29,132,830)	(29,132,830)	(76,372)	(29,209,202)
Utah	UT	(99,859,802)	(539,219)	(100,399,022)	(542,643)	(100,941,665)	(545,840)	(101,487,505)	(550,992)	(102,038,498)	(102,038,498)	(298,463)	(102,336,961)
Idaho	ID	(21,886,401)	(140,321)	(22,026,722)	(140,527)	(22,167,249)	(140,832)	(22,308,081)	(141,488)	(22,449,570)	(22,449,570)	(24,154)	(22,473,724)
Western Wyoming	WYU	(7,259,630)	(38,855)	(7,298,485)	(38,797)	(7,337,283)	(38,740)	(7,376,022)	(38,682)	(7,406,704)	(7,406,704)	4,151	(7,402,553)
Pre-merger Pacific	SG	(567,415)	10,741	(556,674)	10,765	(545,909)	10,790	(535,119)	10,814	(524,305)	(524,305)	1,748	(522,557)
Pre-merger Utah	SG	(1,657,090)	21,281	(1,635,809)	21,313	(1,614,496)	21,344	(1,593,152)	21,376	(1,571,776)	(1,571,776)	2,273	(1,569,503)
Post-merger	SG	(136,663,136)	(660,399)	(137,323,535)	(660,807)	(137,984,341)	(663,044)	(138,647,385)	(672,999)	(139,320,385)	(139,320,385)	(207,710)	(139,528,094)
General Office	SO	(123,170,973)	(544,664)	(123,715,636)	(554,245)	(124,269,881)	(562,880)	(124,832,761)	(579,727)	(125,412,488)	(125,412,488)	(667,282)	(126,079,770)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(144,104)	(978)	(145,082)	(978)	(146,061)	(978)	(147,039)	(978)	(148,018)	(148,018)	-	(148,018)
Customer Service	CN	(7,031,095)	20,779	(7,010,316)	21,272	(6,989,044)	21,765	(6,967,279)	22,259	(6,945,020)	(6,945,020)	35,514	(6,909,506)
Fuel Related	SE	(1,507,918)	2,502	(1,505,415)	2,547	(1,502,868)	2,592	(1,500,275)	2,638	(1,497,638)	(1,497,638)	3,247	(1,494,391)
Total General Plant		(568,284,986)	(2,631,000)	(570,915,986)	(2,646,457)	(573,562,443)	(2,663,462)	(576,225,905)	(2,703,246)	(578,929,151)	(578,929,151)	(1,439,477)	(580,368,628)
<b>Mining Plant:</b>													
Coal Mine	SE	-	-	-	-	-	-	-	-	-	-	-	-
Total Mining Plant		-	-	-	-	-	-	-	-	-	-	-	-
Total Depreciation Reserve		(11,551,542,591)	(73,580,526)	(11,625,123,117)	(73,696,369)	(11,698,819,486)	(73,894,945)	(11,772,714,431)	(74,260,379)	(11,846,974,810)	(11,846,974,810)	(16,398,543)	(11,863,373,353)



PacifiCorp  
Oregon General Rate Case - December 2023  
Jun 2021 - December 2022 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance		Adjusted Reserve Balance		Adjusted Reserve Balance		Adjusted Reserve Balance		Adjusted Reserve Balance		CY 2022 YE Balance	Incremental Reserve For Annualized Depreciation	CY 2022 Adjusted Reserve Year End Balance
		Aug 2022	Adjustments	Sep 2022	Adjustments	Oct 2022	Adjustments	Nov 2022	Adjustments	Dec 2022				
<b>AMORTIZATION RESERVE</b>														
<b>Intangible Plant:</b>														
California	CA	(8,262)	(147)	(8,409)	(147)	(8,556)	(147)	(8,703)	(147)	(8,850)	(8,850)	-	-	(8,850)
Customer Service	CN	(178,280,248)	(1,115,804)	(179,396,053)	(1,115,820)	(180,511,873)	(1,115,437)	(181,627,110)	(1,115,253)	(182,742,362)	(182,742,362)	13,245	13,245	(182,729,117)
Idaho	ID	(1,002,610)	(1,833)	(1,004,443)	(1,833)	(1,006,276)	(1,833)	(1,008,109)	(1,833)	(1,009,943)	(1,009,943)	(10,563)	(10,563)	(1,020,506)
Pre-merger Utah	SG	(411,607)	(1,039)	(412,646)	(1,039)	(413,686)	(1,039)	(414,725)	(1,039)	(415,764)	(415,764)	(12,470)	(12,470)	(428,234)
Montana	MT	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(137,737)	(611)	(138,348)	(611)	(138,959)	(611)	(139,570)	(611)	(140,180)	(140,180)	6	6	(140,175)
Fuel Related	SE	59,752	4,913	64,666	4,981	69,647	5,049	74,627	5,117	79,614	79,614	4,895	4,895	84,709
Post-merger	SG	(113,441,445)	(531,797)	(113,973,242)	(531,619)	(114,504,861)	(531,441)	(115,036,302)	(531,262)	(115,567,564)	(115,567,564)	12,845	12,845	(115,554,719)
Hydro Reicensing	SG-P	(43,496,159)	(218,725)	(43,714,885)	(218,715)	(43,933,600)	(218,705)	(44,152,305)	(218,695)	(44,371,000)	(44,371,000)	726	726	(44,370,274)
Hydro Reicensing	SG-U	(5,919,429)	(11,415)	(5,930,844)	(11,375)	(5,942,219)	(11,335)	(5,953,555)	(11,295)	(5,964,850)	(5,964,850)	2,887	2,887	(5,961,962)
General Office	SO	(332,876,907)	(1,253,872)	(334,130,780)	(1,261,875)	(335,392,655)	(1,264,270)	(336,656,925)	(1,295,267)	(337,952,191)	(337,952,191)	(1,182,602)	(1,182,602)	(339,134,793)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	UT	31,939,325	(2,672)	31,936,653	(2,672)	31,933,981	(2,672)	31,931,309	(2,672)	31,928,637	31,928,637	(5)	(5)	31,928,632
Washington	WA	(14,365)	(262)	(14,627)	(262)	(14,889)	(262)	(15,152)	(262)	(15,414)	(15,414)	-	-	(15,414)
Eastern Wyoming	WYP	(395,345)	(1,349)	(396,694)	(1,336)	(398,030)	(1,324)	(399,354)	(1,311)	(400,665)	(400,665)	909	909	(399,756)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	(74,111,750)	-	-	(74,111,750)
Total Intangible Plant	-	(718,096,786)	(3,134,615)	(721,231,401)	(3,142,125)	(724,373,526)	(3,144,026)	(727,517,553)	(3,174,530)	(730,692,083)	(730,692,083)	(1,170,127)	(1,170,127)	(731,862,209)
<b>Hydro Production Plant:</b>														
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(3,502,880)	(25,975)	(3,528,855)	(25,975)	(3,554,829)	(25,975)	(3,580,804)	(25,975)	(3,606,778)	(3,606,778)	-	-	(3,606,778)
Post-merger	SG-U	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant	-	(3,502,880)	(25,975)	(3,528,855)	(25,975)	(3,554,829)	(25,975)	(3,580,804)	(25,975)	(3,606,778)	(3,606,778)	-	-	(3,606,778)
<b>Other Production Plant:</b>														
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>General Plant:</b>														
California	CA	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	(505,860)	-	-	(505,860)
General Office	CN	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	ID	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	(333,771)	-	-	(333,771)
Oregon	OR	(5,117,727)	(26,909)	(5,144,636)	(26,909)	(5,171,544)	(26,909)	(5,198,453)	(26,909)	(5,225,362)	(5,225,362)	-	-	(5,225,362)
General Office	SO	(1,301,197)	(9,024)	(1,310,222)	(9,024)	(1,319,246)	(9,024)	(1,328,270)	(9,024)	(1,337,295)	(1,337,295)	-	-	(1,337,295)
Utah	UT	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	(33,127)	-	-	(33,127)
Washington	WA	(1,967,795)	(8,022)	(1,975,818)	(8,022)	(1,983,840)	(8,022)	(1,991,862)	(8,022)	(1,999,885)	(1,999,885)	-	-	(1,999,885)
Eastern Wyoming	WYP	(4,516,508)	(4,431)	(4,520,939)	(4,431)	(4,525,370)	(4,431)	(4,529,801)	(4,431)	(4,534,231)	(4,534,231)	-	-	(4,534,231)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant	-	(13,775,985)	(48,386)	(13,824,371)	(48,386)	(13,872,757)	(48,386)	(13,921,143)	(48,386)	(13,969,530)	(13,969,530)	-	-	(13,969,530)
Total Amortization Reserve	-	(735,375,651)	(3,208,976)	(738,584,627)	(3,216,485)	(741,801,112)	(3,218,387)	(745,019,500)	(3,248,891)	(748,268,391)	(748,268,391)	(1,170,127)	(1,170,127)	(749,438,517)
Total Depreciation & Amortization Reserve	-	(12,286,918,242)	(76,789,502)	(12,363,707,744)	(76,912,854)	(12,440,620,598)	(77,113,332)	(12,517,733,930)	(77,509,270)	(12,595,243,201)	(12,595,243,201)	(17,588,670)	(17,588,670)	(12,612,811,871)

Ref. 6.2.3

**PacifiCorp  
Oregon Results of Operations - December 2023  
Oregon Coal-Fired Steam Plant Depreciation**

**Depreciation Reserve Adjustment**

	<u>Total Company</u>	<u>Factor</u>
<b>Adjustment to June 2021 Reserve:</b>		
Steam Plant Accumulated Depreciation	(903,108,676)	SG
Steam Plant Accumulated Depreciation	-	SG
	<u>(903,108,676)</u>	

**Depreciation Reserve Adjustment By Plant**

<u>Plant</u>	<u>Factor</u>	<u>Adjustment to Expense (Yr Ended Jun 2021)</u>
CHOLLA	SG	-
NAUGHTON	SG	(30,064,073)
HUNTINGTON	SG	(89,320,910)
HUNTER	SG	(195,988,110)
CRAIG	SG	(23,396,883)
HAYDEN	SG	(20,602,217)
COLSTRIP	SG	(15,343,966)
DAVE JOHNSTON	SG	(150,994,556)
JIM BRIDGER	SG	(281,627,624)
WYODAK	SG	(95,770,338)
		<u>(903,108,676)</u>

This is the increase in the depreciation reserve June 2021 starting balance in adjustment 6.2. This reflects the increase from January 2008 to June 2021 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.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Hydro Decommissioning**  
**Spending, Accruals, and Balances - East Side, West Side, and Total Resources**

<b>West Side</b>			
	<u>Spend</u>	<u>Accruals</u>	<u>Balance</u>
June-20	-	(173,152)	(7,919,677)
July-20	2,044	(173,152)	(8,090,786)
August-20	-	(173,152)	(8,263,937)
September-20	-	(173,152)	(8,437,089)
October-20	-	(173,152)	(8,610,241)
November-20	-	(173,152)	(8,783,393)
December-20	-	(173,152)	(8,956,544)
January-21	-	60,700	(8,895,845)
February-21	-	60,700	(8,835,145)
March-21	-	60,700	(8,774,445)
April-21	-	60,700	(8,713,746)
May-21	419,290	60,700	(8,233,755)
June-21	1,206,269	60,700	(6,966,787)

<b>East Side</b>			
	<u>Spend</u>	<u>Accruals</u>	<u>Balance</u>
June-20	-	25,600	(302,944)
July-20	-	25,600	(277,344)
August-20	-	25,600	(251,744)
September-20	-	25,600	(226,143)
October-20	-	25,600	(200,543)
November-20	-	25,600	(174,943)
December-20	-	25,600	(149,342)
January-21	-	(23,356)	(172,698)
February-21	-	(23,356)	(196,054)
March-21	-	(23,356)	(219,410)
April-21	-	(23,356)	(242,766)
May-21	-	(23,356)	(266,122)
June-21	-	(23,356)	(289,478)

<b>Total Resources</b>			
	<u>Spend</u>	<u>Accruals</u>	<u>Balance</u>
June-20	-	(147,551)	(8,222,622)
July-20	2,044	(147,551)	(8,368,130)
August-20	-	(147,551)	(8,515,681)
September-20	-	(147,551)	(8,663,232)
October-20	-	(147,551)	(8,810,784)
November-20	-	(147,551)	(8,958,335)
December-20	-	(147,551)	(9,105,887)
January-21	-	37,344	(9,068,543)
February-21	-	37,344	(9,031,199)
March-21	-	37,344	(8,993,855)
April-21	-	37,344	(8,956,512)
May-21	419,290	37,344	(8,499,878)
June-21	1,206,269	37,344	(7,256,265)

<b>West Side</b>			
	<u>Spend</u>	<u>Accruals</u>	<u>Balance</u>
July-21	-	60,700	(6,906,087)
August-21	-	60,700	(6,845,387)
September-21	-	60,700	(6,784,687)
October-21	-	60,700	(6,723,988)
November-21	-	60,700	(6,663,288)
December-21	-	60,700	(6,602,588)
January-22	-	60,700	(6,541,889)
February-22	-	60,700	(6,481,189)
March-22	-	60,700	(6,420,489)
April-22	-	60,700	(6,359,790)
May-22	-	60,700	(6,299,090)
June-22	-	60,700	(6,238,390)
July-22	-	60,700	(6,177,690)
August-22	-	60,700	(6,116,991)
September-22	-	60,700	(6,056,291)
October-22	-	60,700	(5,995,591)
November-22	-	60,700	(5,934,892)
December-22	-	60,700	(5,874,192)

<b>East Side</b>			
	<u>Spend</u>	<u>Accruals</u>	<u>Balance</u>
July-21	-	(23,356)	(312,834)
August-21	-	(23,356)	(336,190)
September-21	-	(23,356)	(359,546)
October-21	-	(23,356)	(382,902)
November-21	-	(23,356)	(406,258)
December-21	-	(23,356)	(429,614)
January-22	-	(23,356)	(452,970)
February-22	-	(23,356)	(476,326)
March-22	-	(23,356)	(499,682)
April-22	-	(23,356)	(523,038)
May-22	-	(23,356)	(546,394)
June-22	-	(23,356)	(569,750)
July-22	-	(23,356)	(593,106)
August-22	-	(23,356)	(616,462)
September-22	-	(23,356)	(639,818)
October-22	-	(23,356)	(663,174)
November-22	-	(23,356)	(686,529)
December-22	-	(23,356)	(709,885)

<b>Total Resources</b>			
	<u>Spend</u>	<u>Accruals</u>	<u>Balance</u>
July-21	-	37,344	(7,218,921)
August-21	-	37,344	(7,181,577)
September-21	-	37,344	(7,144,233)
October-21	-	37,344	(7,106,890)
November-21	-	37,344	(7,069,546)
December-21	-	37,344	(7,032,202)
January-22	-	37,344	(6,994,858)
February-22	-	37,344	(6,957,515)
March-22	-	37,344	(6,920,171)
April-22	-	37,344	(6,882,827)
May-22	-	37,344	(6,845,484)
June-22	-	37,344	(6,808,140)
July-22	-	37,344	(6,770,796)
August-22	-	37,344	(6,733,452)
September-22	-	37,344	(6,696,109)
October-22	-	37,344	(6,658,765)
November-22	-	37,344	(6,621,421)
December-22	-	37,344	(6,584,077)

<b>West Side</b>			
	<u>Spend</u>	<u>Accruals</u>	<u>Balance</u>
January-23	-	60,700	(5,813,492)
February-23	-	60,700	(5,752,793)
March-23	-	60,700	(5,692,093)
April-23	-	60,700	(5,631,393)
May-23	-	60,700	(5,570,693)
June-23	-	60,700	(5,509,994)
July-23	-	60,700	(5,449,294)
August-23	-	60,700	(5,388,594)
September-23	-	60,700	(5,327,895)
October-23	-	60,700	(5,267,195)
November-23	-	60,700	(5,206,495)
December-23	-	60,700	(5,145,796)

<b>East Side</b>			
	<u>Spend</u>	<u>Accruals</u>	<u>Balance</u>
January-23	-	(23,356)	(733,241)
February-23	-	(23,356)	(756,597)
March-23	-	(23,356)	(779,953)
April-23	-	(23,356)	(803,309)
May-23	-	(23,356)	(826,665)
June-23	-	(23,356)	(850,021)
July-23	-	(23,356)	(873,377)
August-23	-	(23,356)	(896,733)
September-23	-	(23,356)	(920,089)
October-23	-	(23,356)	(943,445)
November-23	-	(23,356)	(966,801)
December-23	-	(23,356)	(990,157)

<b>Total Resources</b>			
	<u>Spend</u>	<u>Accruals</u>	<u>Balance</u>
January-23	-	37,344	(6,546,734)
February-23	-	37,344	(6,509,390)
March-23	-	37,344	(6,472,046)
April-23	-	37,344	(6,434,702)
May-23	-	37,344	(6,397,359)
June-23	-	37,344	(6,360,015)
July-23	-	37,344	(6,322,671)
August-23	-	37,344	(6,285,327)
September-23	-	37,344	(6,247,984)
October-23	-	37,344	(6,210,640)
November-23	-	37,344	(6,173,296)
December-23	-	37,344	(6,135,952)

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Depreciation Allocation Correction**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Remove system allocated deferral	403SP	1	(325,833)	SG	26.070%	(84,946)	6.3.1
Remove system allocated give-back reversal	403SP	1	(1,081,784)	SG	26.070%	(282,025)	6.3.2
			<u>(1,407,617)</u>			<u>(366,971)</u>	

**Description of Adjustment:**

The Company established a regulatory asset to track and defer any aggregate net increase in allocated depreciation expense in dockets in Wyoming, Utah and Idaho for depreciation rates that became effective January 1, 2014. New depreciation rates went into effect in January of 2021, which no longer require the giveback reallocation. This adjustment removes the deferral recorded in 2020 in base period data from test period results.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Depreciation Allocation Correction**

Actual      Account      Amount      Factor  
403SP      **325,833**      SG      **Ref. 6.3**

<u>Calendar</u>	<u>Year</u>	<u>Period</u>	<u>Account</u>	<u>Amount</u>	<u>Description</u>	<u>FERC</u>	<u>FERC</u>	<u>Actual</u>
			<u>Number</u>			<u>Account</u>	<u>Location</u>	<u>Allocation</u>
	2020	7	565131	10,670	Amortize Deferred Depr Exp - Steam - UT	4032000	1	SG
	2020	7	565131	36,849	Amortize Deferred Depr Exp - Steam - WY	4032000	1	SG
	2020	7	565131	(170,211)	Defer Deprec Expense - Steam - ID	4032000	1	SG
	2020	7	565131	(432)	Cholla Plant FERC Adj-Accum Depr	4032000	1	SG
	2020	7	565131	184,935	ID - ECAM Def Depr Amort - FY2020	4032000	1	SG
	2020	8	565131	10,670	Amortize Deferred Depr Exp - Steam - UT	4032000	1	SG
	2020	8	565131	36,849	Amortize Deferred Depr Exp - Steam - WY	4032000	1	SG
	2020	8	565131	(169,827)	Defer Deprec Expense - Steam - ID	4032000	1	SG
	2020	8	565131	(432)	Cholla Plant FERC Adj-Accum Depr	4032000	1	SG
	2020	8	565131	182,833	ID - ECAM Def Depr Amort - FY2020	4032000	1	SG
	2020	9	565131	10,670	Amortize Deferred Depr Exp - Steam - UT	4032000	1	SG
	2020	9	565131	36,849	Amortize Deferred Depr Exp - Steam - WY	4032000	1	SG
	2020	9	565131	(171,927)	Defer Deprec Expense - Steam - ID	4032000	1	SG
	2020	9	565131	(432)	Cholla Plant FERC Adj-Accum Depr	4032000	1	SG
	2020	9	565131	178,731	ID - ECAM Def Depr Amort - FY2020	4032000	1	SG
	2020	10	565131	10,670	Amortize Deferred Depr Exp - Steam - UT	4032000	1	SG
	2020	10	565131	36,849	Amortize Deferred Depr Exp - Steam - WY	4032000	1	SG
	2020	10	565131	(172,193)	Defer Deprec Expense - Steam - ID	4032000	1	SG
	2020	10	565131	(432)	Cholla Plant FERC Adj-Accum Depr	4032000	1	SG
	2020	10	565131	175,280	ID - ECAM Def Depr Amort - FY2020	4032000	1	SG
	2020	11	565131	10,670	Amortize Deferred Depr Exp - Steam - UT	4032000	1	SG
	2020	11	565131	36,849	Amortize Deferred Depr Exp - Steam - WY	4032000	1	SG
	2020	11	565131	(171,907)	Defer Deprec Expense - Steam - ID	4032000	1	SG
	2020	11	565131	(432)	Cholla Plant FERC Adj-Accum Depr	4032000	1	SG
	2020	11	565131	182,085	ID - ECAM Def Depr Amort - FY2020	4032000	1	SG
	2020	12	565131	10,670	Amortize Deferred Depr Exp - Steam - UT	4032000	1	SG
	2020	12	565131	36,849	Amortize Deferred Depr Exp - Steam - WY	4032000	1	SG
	2020	12	565131	(172,711)	Defer Deprec Expense - Steam - ID	4032000	1	SG
	2020	12	565131	(432)	Cholla Plant FERC Adj-Accum Depr	4032000	1	SG
	2020	12	565131	168,220	ID - ECAM Def Depr Amort - FY2021	4032000	1	SG
	Total			<u>325,833</u>				

**PacifiCorp  
Oregon General Rate Case - December 2023  
Depreciation Allocation Correction**

Actual	<u>Account</u> 403SP	<u>Amount</u> 1,081,784	<u>Factor</u> SG	Ref. 6.3				
<u>Calendar</u>	<u>Year</u>	<u>Period</u>	<u>Account</u> <u>Number</u>	<u>Amount</u>	<u>Description</u>	<u>FERC</u> <u>Account</u>	<u>FERC</u> <u>Location</u>	<u>Actual</u> <u>Allocation</u>
	2020	7	565131	50,294	OR - Reverse give-back - Colstrip	4032000	108	SG
	2020	7	565131	12,368	OR - Reverse give-back - Hunter Common	4032000	108	SG
	2020	7	565131	37,736	OR - Reverse give-back - Hunter Unit 1	4032000	108	SG
	2020	7	565131	24,881	OR - Reverse give-back - Hunter Unit 2	4032000	108	SG
	2020	7	565131	52,486	OR - Reverse give-back - Hunter Unit 3	4032000	108	SG
	2020	7	565131	2,533	OR - Reverse give-back - Hunter 1&2 Commor	4032000	108	SG
	2020	8	565131	50,294	OR - Reverse give-back - Colstrip	4032000	108	SG
	2020	8	565131	12,368	OR - Reverse give-back - Hunter Common	4032000	108	SG
	2020	8	565131	37,736	OR - Reverse give-back - Hunter Unit 1	4032000	108	SG
	2020	8	565131	24,881	OR - Reverse give-back - Hunter Unit 2	4032000	108	SG
	2020	8	565131	52,486	OR - Reverse give-back - Hunter Unit 3	4032000	108	SG
	2020	8	565131	2,533	OR - Reverse give-back - Hunter 1&2 Commor	4032000	108	SG
	2020	9	565131	50,294	OR - Reverse give-back - Colstrip	4032000	108	SG
	2020	9	565131	12,368	OR - Reverse give-back - Hunter Common	4032000	108	SG
	2020	9	565131	37,736	OR - Reverse give-back - Hunter Unit 1	4032000	108	SG
	2020	9	565131	24,881	OR - Reverse give-back - Hunter Unit 2	4032000	108	SG
	2020	9	565131	52,486	OR - Reverse give-back - Hunter Unit 3	4032000	108	SG
	2020	9	565131	2,533	OR - Reverse give-back - Hunter 1&2 Commor	4032000	108	SG
	2020	10	565131	50,294	OR - Reverse give-back - Colstrip	4032000	108	SG
	2020	10	565131	12,368	OR - Reverse give-back - Hunter Common	4032000	108	SG
	2020	10	565131	37,736	OR - Reverse give-back - Hunter Unit 1	4032000	108	SG
	2020	10	565131	24,881	OR - Reverse give-back - Hunter Unit 2	4032000	108	SG
	2020	10	565131	52,486	OR - Reverse give-back - Hunter Unit 3	4032000	108	SG
	2020	10	565131	2,533	OR - Reverse give-back - Hunter 1&2 Commor	4032000	108	SG
	2020	11	565131	50,294	OR - Reverse give-back - Colstrip	4032000	108	SG
	2020	11	565131	12,368	OR - Reverse give-back - Hunter Common	4032000	108	SG
	2020	11	565131	37,736	OR - Reverse give-back - Hunter Unit 1	4032000	108	SG
	2020	11	565131	24,881	OR - Reverse give-back - Hunter Unit 2	4032000	108	SG
	2020	11	565131	52,486	OR - Reverse give-back - Hunter Unit 3	4032000	108	SG
	2020	11	565131	2,533	OR - Reverse give-back - Hunter 1&2 Commor	4032000	108	SG
	2020	12	565131	50,294	OR - Reverse give-back - Colstrip	4032000	108	SG
	2020	12	565131	12,368	OR - Reverse give-back - Hunter Common	4032000	108	SG
	2020	12	565131	37,736	OR - Reverse give-back - Hunter Unit 1	4032000	108	SG
	2020	12	565131	24,881	OR - Reverse give-back - Hunter Unit 2	4032000	108	SG
	2020	12	565131	52,486	OR - Reverse give-back - Hunter Unit 3	4032000	108	SG
	2020	12	565131	2,533	OR - Reverse give-back - Hunter 1&2 Commor	4032000	108	SG
	Total			<u>1,081,784</u>				

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Repowering Buy Downs**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Dunlap Buy-down	407	1	26,889,854	OR	Situs	26,889,854	6.4.1
Foote Creek Buy-Down	407	1	<u>2,631,642</u>	OR	Situs	2,631,642	6.4.1
			<u>29,521,495</u>				
Repowered Facilities Buy-down	407	1	(3,359,575)	OR	Situs	(3,359,575)	6.4.2
Repowered Facilities Buy-down	407	3	<u>(3,388,979)</u>	OR	Situs	(3,388,979)	6.4.3
			<u>(6,748,553)</u>				
<b>Adjustment to Reserves:</b>							
RAC buy-down reserves adj.	108OP	1	(193,318,297)	OR	Situs	(193,318,297)	6.4.1
Repowered Facilities Reserve	108OP	3	10,122,830	OR	Situs	10,122,830	6.4.3
<b>Adjustment to Tax</b>							
Schedule M Adjustment	SCHMAT	3	(3,388,979)	OR	Situs	(3,388,979)	
Deferred Income Tax Expense	41110	3	833,235	OR	Situs	833,235	
Accumulated Def Inc Tax Balance	282	3	(2,488,860)	OR	Situs	(2,488,860)	

**Description of Adjustment:**

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 Excess Deferred Income Tax (EDIT) balances that resulted from the Tax and Job Cuts Act (TCJA), and a portion of the Company's deferred FERC Open Access Transmission Tariff (OATT) revenues.

This adjustment corrects the allocation of expenses recorded as a result of the buy-down in the base period for the Dunlap, and Foote Creek wind facilities, as well as bring 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 2023  
Repowering Buy-Downs

Year	Account	Actual FERC Account	Revised FERC Account	Text	Booked Alloc.	Correct Alloc.	Amount
2020	565243	4034000	4070000	Oregon Portion of NBV - Dunlap	NUTIL	OR	26,889,854
2021	565243	4034000	4070000	Oregon Portion of NBV - Foote Creek	NUTIL	OR	2,631,642

Ref 6.4

Ref 6.4

Year	Account	Actual FERC Account	Revised FERC Account	Text	Booked Alloc.	Correct Alloc.	June 2021 EOP
2021	145243	1085000	N/A	Production Plant - OR Buy-down Adj.	NUTIL	OR	(193,318,297)

Ref 6.4



**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Repowering Buy-Downs**  
**Base Period Amortization**

<b>Amortization Expense</b>	<b>Jan-21</b>	<b>Feb-21</b>	<b>Mar-21</b>	<b>Apr-21</b>	<b>May-21</b>	<b>Jun-21</b>
Depr Adj - Dunlap OR Wind Buydown	(74,694)	(74,694)	(74,694)	(74,694)	(74,694)	(74,694)
Depr Adj - Foote Creek OR Wind Buydown	-	-	(7,351)	(7,351)	(7,351)	(7,351)
Depr Adj - Glenrock 1 OR Wind Buydown	(56,639)	(56,639)	(56,639)	(56,639)	(56,639)	(56,639)
Depr Adj - Glenrock 3 OR Wind Buydown	(20,500)	(20,500)	(20,500)	(20,500)	(20,500)	(20,500)
Depr Adj - Goodnoe Hills OR Wind Buydown	(66,309)	(66,309)	(66,309)	(66,309)	(66,309)	(66,309)
Depr Adj - High Plains OR Wind Buydown	(74,042)	(74,042)	(74,042)	(74,042)	(74,042)	(74,042)
Depr Adj - Leaning Juniper OR Wind Buydown	(48,430)	(48,430)	(48,430)	(48,430)	(48,430)	(48,430)
Depr Adj - Marengo 1 OR Wind Buydown	(75,094)	(75,094)	(75,094)	(75,094)	(75,094)	(75,094)
Depr Adj - Marengo 2 OR Wind Buydown	(39,822)	(39,822)	(39,822)	(39,822)	(39,822)	(39,822)
Depr Adj - McFadden Ridge OR Wind Buydown	(18,898)	(18,898)	(18,898)	(18,898)	(18,898)	(18,898)
Depr Adj - Seven Mile Hill 1 OR Wind Buydown	(66,713)	(66,713)	(66,713)	(66,713)	(66,713)	(66,713)
Depr Adj - Seven Mile Hill 2 OR Wind Buydown	(13,888)	(13,888)	(13,888)	(13,888)	(13,888)	(13,888)
<b>Total</b>	<b>(555,028)</b>	<b>(555,028)</b>	<b>(562,379)</b>	<b>(562,379)</b>	<b>(562,379)</b>	<b>(562,379)</b>

**12 ME June 2021 (3,359,575) Ref 6.4.3**

<b>Accumulated Amortization</b>	<b>Jan-21</b>	<b>Feb-21</b>	<b>Mar-21</b>	<b>Apr-21</b>	<b>May-21</b>	<b>Jun-21</b>
Dunlap OR Wind Buydown	74,694	149,388	224,082	298,776	373,470	448,164
Foote Creek OR Wind Buydown	-	-	7,351	14,702	22,053	29,404
Glenrock 1 OR Wind Buydown	56,639	113,278	169,917	226,556	283,195	339,833
Glenrock 3 OR Wind Buydown	20,500	40,999	61,499	81,999	102,499	122,998
Goodnoe Hills OR Wind Buydown	66,309	132,617	198,926	265,235	331,543	397,852
High Plains OR Wind Buydown	74,042	148,084	222,126	296,168	370,210	444,252
Leaning Juniper OR Wind Buydown	48,430	96,860	145,290	193,721	242,151	290,581
Marengo 1 OR Wind Buydown	75,094	150,189	225,283	300,378	375,472	450,567
Marengo 2 OR Wind Buydown	39,822	79,644	119,466	159,288	199,110	238,932
McFadden Ridge OR Wind Buydown	18,898	37,796	56,693	75,591	94,489	113,387
Seven Mile Hill 1 OR Wind Buydown	66,713	133,426	200,139	266,852	333,564	400,277
Seven Mile Hill 2 OR Wind Buydown	13,888	27,776	41,664	55,552	69,440	83,328
<b>Total</b>	<b>555,028</b>	<b>1,110,057</b>	<b>1,672,436</b>	<b>2,234,816</b>	<b>2,797,195</b>	<b>3,359,575</b>

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Repowering Buy-Downs**  
**Accumulated Amortization of Buy-down Balance**

	<u>Beginning Balance</u>	<u>Amortization Expense</u>	<u>Ending Balance</u>	
6/30/2021			3,359,575	<b>Ref 6.4.2</b>
7/31/2021	3,359,575	(562,379)	3,921,954	
8/31/2021	3,921,954	(562,379)	4,484,334	
9/30/2021	4,484,334	(562,379)	5,046,713	
10/31/2021	5,046,713	(562,379)	5,609,092	
11/30/2021	5,609,092	(562,379)	6,171,472	
12/31/2021	6,171,472	(562,379)	6,733,851	
1/31/2022	6,733,851	(562,379)	7,296,231	
2/28/2022	7,296,231	(562,379)	7,858,610	
3/31/2022	7,858,610	(562,379)	8,420,990	
4/30/2022	8,420,990	(562,379)	8,983,369	
5/31/2022	8,983,369	(562,379)	9,545,748	
6/30/2022	9,545,748	(562,379)	10,108,128	
7/31/2022	10,108,128	(562,379)	10,670,507	
8/31/2022	10,670,507	(562,379)	11,232,887	
9/30/2022	11,232,887	(562,379)	11,795,266	
10/31/2022	11,795,266	(562,379)	12,357,646	
11/30/2022	12,357,646	(562,379)	12,920,025	
12/31/2022	12,920,025	(562,379)	13,482,404	<i>Below</i>
Annual Amortization		(6,748,553)		<i>Below</i>

Base Period Amortization Expense	(3,359,575)	Ref 6.4.2
Pro Forma Amortization Expense	(6,748,553)	Above
<b>Adjustment to Expense</b>	<b>(3,388,979)</b>	<b>Ref 6.4</b>

Base Period Accum. Amort.	3,359,575	Above
Pro Forma Accum. Amort.	13,482,404	Above
<b>Adjustment to Accum.</b>	<b>10,122,830</b>	<b>Ref 6.4</b>

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Coal Depreciable Life Update**

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	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Depreciation Expense	403SP	3	(3,108,984)	SG	26.070%	(810,523)	6.5.1
<b>Adjustment to Rate Base:</b>							
Depreciation Reserve	108SP	3	1,554,492	SG	26.070%	405,261	6.5.1
<b>Adjustment to Tax</b>							
Schedule M Adjustment	SCHMAT	3	3,108,984	SG	26.070%	810,523	
Deferred Income Tax Expense	41110	3	(764,394)	SG	26.070%	(199,280)	
Accumulated Def Inc Tax Balance	282	3	382,197	SG	26.070%	99,640	

**Description of Adjustment:**

This pro forma adjustment includes the change in depreciation expense and reserve to align the depreciation lives with the 2021 IRP retirement dates for the following coal fired plants: Colstrip, Craig 2, and Hayden 1 & 2. Please see Page 6.5.2 for a summary of the proposed change in end of depreciable life for each generation facility included in this adjustment. Incremental reserves are reflected on a 13-month average basis.

PacifiCorp  
Oregon General Rate Case - December 2023  
Coal Depreciable Life Update  
Change in Depreciation Expense

	PROPOSED END OF DEPRECIABLE LIFE	AS OF DEC 31, 2022			ACCEL. DEPR. RATES		COMPOSITE REMAINING LIFE	EXISTING RATES		CHANGE
		ORIGINAL COST	ACCUM. RESERVES	FUTURE ACCURALS	ANNUAL AMOUNT	ACCRUAL RATE		CURRENT RATE <sup>1</sup>	CURRENT ACCRUAL	
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)
		<b>522,216,232</b>	<b>418,399,841</b>	<b>123,791,214</b>	<b>34,961,351</b>				<b>38,070,335</b>	<b>(3,108,984)</b>
										<b>Ref. 6.5</b>
									<b>Incremental Reserve Impact</b>	<b>1,554,492</b>
										<b>Ref. 6.5</b>

Note 1 - Current rates are per approved 2018 Depreciation Study.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Coal Depreciable Life Update**  
**Summary of Change in Depreciable Life**

COLSTRIP  
 CRAIG - UNIT 2 & COMMON  
 HAYDEN UNIT 1  
 HAYDEN UNIT 2

End of Depreciable Life			
Current	2021 IRP	Change	
2027	2025	2	years Acceleration
2026	Sep-28	1.8	years Extension
2023	2028	5	years Extension
2023	2027	4	years Extension

**PacifiCorp  
Oregon General Rate Case - December 2023  
Bridger Mine Reclamation Costs**

PAGE 6.6\_REDACTED

Note: Please see Confidential Exhibit PAC/1007 for redacted information.

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Bridger Reclamation Costs	501	3	[REDACTED]	SE	25.068%	[REDACTED]	6.6.1
<b>Adjustment to Rate Base</b>							
Bridger Reclamation Costs	254	3	[REDACTED]	OR	Situs	[REDACTED]	6.6.1
<b>Adjustment to Tax:</b>							
Schedule M Adjustment	SCHMAT	3	[REDACTED]	SE	25.068%	[REDACTED]	6.6.1
Deferred Income Tax Expense	41110	3	[REDACTED]	SE	25.068%	[REDACTED]	6.6.1
Accumulated Def Inc Tax Balance	190	3	[REDACTED]	OR	Situs	[REDACTED]	6.6.1

**Description of Adjustment:**

This adjustment adds into test period results Bridger Mine final reclamation costs and incremental depreciation expense as approved in the Company's 2021 general rate case (UE 374), Order No. 20-473. Consistent with the approved adjustment from UE 374, an annual level of expense is reflected in this adjustment, while the regulatory liability balance is included on a 13-month-average basis for the year ending December 2023.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Bridger Final Reclamation Costs**

Note: Please see Confidential Exhibit PAC/1007 for redacted information.

Annual Incremental Contribution for Reclamation [REDACTED] Ref 6.6  
 Incremental Depreciation Expense Prior to Reclamation [REDACTED]  
 Amortization Period (Years) 5  
 Annual Incremental Depreciation Expense [REDACTED] Ref 6.6

TOTAL COMPANY				
501 Mthly Accum.	SCHMAT Tax	41110 DIT Exp	254 Reg. Liab.	190 ADIT

Dec-20	-		-	-
Jan-21				
Feb-21				
Mar-21				
Apr-21				
May-21				
Jun-21				
Jul-21				
Aug-21				
Sep-21				
Oct-21				
Nov-21				
Dec-21				
Jan-22				
Feb-22				
Mar-22				
Apr-22				
May-22				
Jun-22				
Jul-22				
Aug-22				
Sep-22				
Oct-22				
Nov-22				
Dec-22				
Jan-23				
Feb-23				
Mar-23				
Apr-23				
May-23				
Jun-23				
Jul-23				
Aug-23				
Sep-23				
Oct-23				
Nov-23				
Dec-23				

<b>Annual Total</b>	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
---------------------	------------	------------	------------	------------

Ref 6.6      Ref 6.6  
 13 Mo. Avg. - Total Company [REDACTED]  
 13 Mo. Avg. - Oregon Allocated [REDACTED]  
 EOP June 2021 Balance [REDACTED]  
**Adjustment** [REDACTED]

\*Oregon 2023 SE Factor      25.068%      Ref 6.6      Ref 6.6

## Tab 7 - Taxes



**PacifiCorp**  
**Oregon General Rate Case – December 2023**  
**Tax Adjustment Index**

The following adjustments were used to arrive at the normalized levels of tax expenses. The Company's 12 months ended June 2021 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 Balance
- 7.5 Pro Forma Tax Balances
- 7.6 Wyoming Wind Generation Tax
- 7.7 AFUDC Equity
- 7.8 Tax Cuts and Jobs Act EDIT Adjustment
- 7.9 OCAT & Metro BIT

The tax impacts of the following adjustments are included within the adjustment itself:

- Insurance Expense, 4.5
- Repowering Buy-Downs, page 6.4
- Coal Depreciable Life Update, page 6.5
- Bridger Mine Reclamation Costs, page 6.6
- 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 Postretirement Plan Balances Removal, page 8.8
- Remove Rolling Hills, page 8.9
- Deer Creek Mine Closure, page 8.10
- Emissions Control Investment Adjustment, page 8.11
- Transmission Project Adjustment, page 8.12
- Cholla Unit 4 Retirement, page 8.13
- Wind Project Deferrals Amortization, page 8.14
- Carbon Plant Closure, page 8.16
- Labor Day Wildlife Restoration, page 8.17

The tax impacts of the following adjustment are included within adjustment 7.4 and 7.5:

- Pro Forma Plant Additions 8.4

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Tab 7 Adjustment Summary**

	7.2	7.3	7.4	7.5	7.6	7.7
	Property Tax Expense	Production Tax Credit	PowerTax ADIT	Pro Forma Tax Balances	Wyoming Wind Generation Tax	AFUDC - Equity
Total Adjustments						
1 Operating Revenues:						
2 General Business Revenues	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-
7						
8 Operating Expenses:						
9 Steam Production	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-
12 Other Power Supply	-	-	-	-	-	-
13 Transmission	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	-	-	-	-	-	-
19						
20 Total O&M Expenses	-	-	-	-	-	-
21						
22 Depreciation	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-
24 Taxes Other Than Income	6,547,693	6,524,691	-	-	23,002	-
25 Income Taxes - Federal	(46,790,008)	(1,308,174)	(20,107,122)	(14,595,358)	(4,612)	218,647
26 Income Taxes - State	79,191	(296,265)	180	(3,305,445)	(1,044)	49,517
27 Income Taxes - Def Net	40,629,511	-	-	16,858,611	12,472,413	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-
30						
31 Total Operating Expenses:	466,386	4,920,252	(20,106,941)	(1,042,192)	602,891	268,164
32						
33 Operating Rev For Return:	(466,386)	(4,920,252)	20,106,941	1,042,192	(602,891)	(268,164)
34						
35 Rate Base:						
36 Electric Plant In Service	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-
44 Working Capital	(379,622)	46,506	(190,051)	(169,198)	(112,191)	2,535
45 Weatherization Loans	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	(379,622)	46,506	(190,051)	(169,198)	(112,191)	2,535
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-
53 Accum Def Income Tax	(50,169,049)	-	-	(42,192,733)	(1,694,247)	-
54 Unamortized ITC	4,573	-	-	-	4,573	-
55 Customer Adv For Const	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	27,572,240	-	-	-	-	-
58						
59 Total Rate Base Deductions	(22,592,236)	-	-	(42,192,733)	(1,689,674)	-
60						
61 Total Rate Base:	(22,971,858)	46,506	(190,051)	(42,361,932)	(1,801,864)	2,535
62						
63 Return on Rate Base	0.013%	-0.122%	0.499%	0.077%	-0.013%	-0.007%
64						
65 Return on Equity	0.026%	-0.234%	0.955%	0.147%	-0.025%	-0.013%
66						
67 TAX CALCULATION:						
68 Operating Revenue	(6,547,693)	(6,524,691)	-	-	(23,002)	-
69 Other Deductions	-	-	-	-	-	-
70 Interest (AFUDC)	(1,090,745)	-	-	-	-	(1,090,745)
71 Interest	(480,344)	972	(3,974)	(885,793)	(37,677)	53
72 Schedule "M" Additions	(93,710,028)	-	-	(74,319,275)	(19,390,753)	-
73 Schedule "M" Deductions	28,327,582	-	-	(626,331)	28,953,913	-
74 Income Before Tax	(127,014,213)	(6,525,663)	3,974	(72,807,151)	(48,306,989)	1,090,692
75						
76 State Income Taxes	79,191	(296,265)	180	(3,305,445)	(1,044)	49,517
77 Taxable Income	(127,093,404)	(6,229,398)	3,794	(69,501,706)	(46,113,852)	1,041,175
78						
79 Federal Income Taxes + Other	(46,790,008)	(1,308,174)	(20,107,122)	(14,595,358)	(4,612)	218,647
APPROXIMATE PRICE CHANGE	(1,631,974)	6,750,067	(27,584,605)	(5,617,390)	648,379	367,893

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Tab 7 Adjustment Summary**

	7.8	7.9
	TCJA EDIT Adjustment	Oregon Corporate Activity Tax & Metro BIT
1 Operating Revenues:		
2 General Business Revenues	-	-
3 Interdepartmental	-	-
4 Special Sales	-	-
5 Other Operating Revenues	-	-
6 Total Operating Revenues	-	-
7		
8 Operating Expenses:		
9 Steam Production	-	-
10 Nuclear Production	-	-
11 Hydro Production	-	-
12 Other Power Supply	-	-
13 Transmission	-	-
14 Distribution	-	-
15 Customer Accounting	-	-
16 Customer Service & Info	-	-
17 Sales	-	-
18 Administrative & General	-	-
19		
20 Total O&M Expenses	-	-
21		
22 Depreciation	-	-
23 Amortization	-	-
24 Taxes Other Than Income	-	-
25 Income Taxes - Federal	(89,239)	(1,227,767)
26 Income Taxes - State	(20,210)	5,845,595
27 Income Taxes - Def Net	11,298,487	-
28 Investment Tax Credit Adj.	-	-
29 Misc Revenue & Expense	-	-
30		
31 Total Operating Expenses:	11,189,038	4,617,828
32		
33 Operating Rev For Return:	(11,189,038)	(4,617,828)
34		
35 Rate Base:		
36 Electric Plant In Service	-	-
37 Plant Held for Future Use	-	-
38 Misc Deferred Debits	-	-
39 Elec Plant Acq Adj	-	-
40 Nuclear Fuel	-	-
41 Prepayments	-	-
42 Fuel Stock	-	-
43 Material & Supplies	-	-
44 Working Capital	(1,035)	43,648
45 Weatherization Loans	-	-
46 Misc Rate Base	-	-
47		
48 Total Electric Plant:	(1,035)	43,648
49		
50 Rate Base Deductions:		
51 Accum Prov For Deprec	-	-
52 Accum Prov For Amort	-	-
53 Accum Def Income Tax	(6,282,069)	-
54 Unamortized ITC	-	-
55 Customer Adv For Const	-	-
56 Customer Service Deposits	-	-
57 Misc Rate Base Deductions	27,572,240	-
58		
59 Total Rate Base Deductions	21,290,171	-
60		
61 Total Rate Base:	21,289,137	43,648
62		
63 Return on Rate Base	-0.305%	-0.115%
64		
65 Return on Equity	-0.583%	-0.220%
66		
67 TAX CALCULATION:		
68 Operating Revenue	-	-
69 Other Deductions	-	-
70 Interest (AFUDC)	-	-
71 Interest	445,158	913
72 Schedule "M" Additions	-	-
73 Schedule "M" Deductions	-	-
74 Income Before Tax	(445,158)	(913)
75		
76 State Income Taxes	(20,210)	5,845,595
77 Taxable Income	(424,948)	(5,846,507)
78		
79 Federal Income Taxes + Other	(89,239)	(1,227,767)
APPROXIMATE PRICE CHANGE	17,444,713	6,335,173

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Interest True-Up**

PAGE 7.1

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Interest	427	3	(12,159,051)	OR	Situs	(12,159,051)	Below
<b>Adjustment Detail:</b>							
Interest June 2021 - Unadjusted			373,768,734			99,963,159	2.15
Interest December 2023 - Normalized			337,754,203			87,804,109	Below
Adjustment:			<u>(36,014,532)</u>			<u>(12,159,051)</u>	
Normalized Rate Base			16,152,666,878			4,199,120,259	2.2
Other & Non-Regulated						-	
Adjusted Rate Base			<u>16,152,666,878</u>			<u>4,199,120,259</u>	2.2
Weighted Cost of Debt			<u>2.091%</u>			<u>2.091%</u>	2.1
Normalized Interest			<u>337,754,203</u>			<u>87,804,109</u>	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**  
**Oregon General Rate Case - December 2023**  
**Property Tax Expense**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Tax:</b> Taxes Other Than Income	408	3	24,011,597	GPS	27.173%	6,524,691	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 2023  
Property Tax Adjustment Summary - Oregon**

<b>FERC Account</b>	<b>G/L Account</b>	<b>Co. Code</b>	<b>Total</b>	<b>Ref</b>
408.15	579000	1000	161,965,403	
<b>Total Accrued Property Tax - 12 Months End. June 2021</b>			<u>161,965,403</u>	
12 Months Ending December 31, 2023 Property Tax Estimate of \$185,977,000			185,977,000	
Less: Property Tax Expense for 12 Months Ended 6/30/2021			(161,965,403)	
<b>Incremental Adjustment to Property Taxes</b>			<u><u>24,011,597</u></u>	<b>Ref 7.2</b>

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Production Tax Credit**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Tax:</b>							
Adj to Pro Forma PTC	40910	3	(77,129,477)	SG	26.070%	(20,107,918)	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 reflects into Test Period results the pro forma period Production Tax Credits (PTC) which are reflected in the Company's Transition Adjustment Mechanism filings annually.

As described in the testimony of Ms. Sherona L. Cheung, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; the Company is not requesting recovery of NPC and PTCs as part of the general rate case. NPC and PTCs are reflected in the Company's Transition Adjustment Mechanism filings annually.

**Pacific Power  
Oregon General Rate Case - December 2023  
Production Tax Credit**

PAGE

7.3.1

<b>Pro Forma Period - December 2023</b>					
<b>Description</b>	<b>Total Available KWh</b>	<b>PIS Date</b>	<b>Total PTC Eligible KWh</b>	<b>Factor (inflated tax per unit)</b>	<b>Federal Income Tax Credit</b>
<b>Wind</b>					
Glenrock KWh <b>[a]</b>	369,732,556	<b>9/24/2019</b>	339,044,754	0.027	9,154,208
Glenrock III KWh <b>[a]</b>	136,868,303	<b>11/24/2019</b>	113,600,691	0.027	3,067,219
Goodnoe KWh	283,697,016	<b>12/20/2019</b>	283,697,016	0.027	7,659,819
High Plains Wind	382,404,334	<b>12/19/2019</b>	382,404,334	0.027	10,324,917
Leaning Juniper 1 KWh	300,456,476	<b>9/13/2019</b>	300,456,476	0.027	8,112,325
Marengo KWh	494,513,357	<b>1/27/2020</b>	494,513,357	0.027	13,351,861
Marengo II KWh	246,897,019	<b>2/25/2020</b>	246,897,019	0.027	6,666,219
McFadden Ridge	116,545,267	<b>11/17/2019</b>	116,545,267	0.027	3,146,722
Rolling Hills KWh <b>[b]</b>	-	<b>10/17/2019</b>	-	-	-
Seven Mile KWh	417,048,284	<b>9/9/2019</b>	417,048,284	0.027	11,260,304
Seven Mile II KWh	87,428,374	<b>9/9/2019</b>	87,428,374	0.027	2,360,566
Dunlap I Wind KWh	476,748,520	<b>9/7/2020</b>	476,748,520	0.027	12,872,210
Foote Creek I Wind	176,189,324	<b>3/24/2021</b>	176,189,324	0.027	4,757,112
Pryor Mountain Wind	822,111,447	<b>VARIOUS</b>	822,111,447	0.027	22,197,009
Cedar Springs Wind II	749,501,065	<b>12/4/2020</b>	749,501,065	0.027	20,236,529
Ekola Flats Wind	819,429,669	<b>VARIOUS</b>	819,429,669	0.027	22,124,601
TB Flats Wind	837,974,852	<b>VARIOUS</b>	837,974,852	0.027	22,625,321
TB Flats Wind II	856,272,738	<b>VARIOUS</b>	856,272,738	0.027	23,119,364
<b>Total KWh Production</b>	<b>7,573,818,600</b>		<b>7,519,863,187</b>		<b>203,036,306</b>
<b>Federal Production Tax Credit</b>					<b>203,036,306</b>

June 2021 Base Period - PTC 125,906,829

Pro forma Adjustment 77,129,477

Repowering In Service dates in **bold** reflect actual in-service dates.

**Ref. 7.3**

**[a]** Total available Kwh is reflected net of the generation that is not considered PTC eligible because the facility was not fully repowered. For Glenrock, the disallowed Kwh represents 8.3% of the total. For Glenrock III, the disallowed Kwh represents 17% disallowed.

**[b]** Oregon does not include Rolling Hills in rate base, therefore, there are no credits for Rolling Hills.



**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**PowerTax ADIT**

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
<b>Adjustment to Tax:</b>							
Accelerated Pollution Control Facilities	281	3	148,004,159	SG	26.070%	38,585,190	
Accumulated Deferred Income Taxes - YE	282	3	2,745,860,351	DITBAL	24.503%	672,825,414	
California	282	3	(67,305,536)	CA	Situs	-	
Idaho	282	3	(181,930,228)	ID	Situs	-	
Oregon	282	3	(753,603,338)	OR	Situs	(753,603,338)	
Other	282	3	(62,185,819)	OTHER	0.000%	-	
Utah	282	3	(1,372,605,502)	UT	Situs	-	
Washington	282	3	(189,228,486)	WA	Situs	-	
Wyoming	282	3	(448,663,332)	WYP	Situs	-	
			<u>(181,657,732)</u>			<u>(42,192,733)</u>	7.4.1
Schedule M Adjustment	SCHMAP	3	(20,640)	SCHMDEXP	22.648%	(4,674)	7.4.1
Schedule M Adjustment	SCHMAT	3	311,609,727	SCHMDEXP	22.648%	70,572,481	7.4.1
Schedule M Adjustment	SCHMAT	3	(225,430,833)	UT	Situs	-	7.4.1
Schedule M Adjustment	SCHMAT	3	(131,758,074)	OR	Situs	(131,758,074)	7.4.1
Schedule M Adjustment	SCHMAT	3	(16,938,208)	ID	Situs	-	7.4.1
Schedule M Adjustment	SCHMAT	3	(5,431,664)	SO	27.173%	(1,475,951)	7.4.1
Schedule M Adjustment	SCHMAT	3	(36,274,387)	CIAC	26.473%	(9,602,772)	7.4.1
Schedule M Adjustment	SCHMAT	3	(3,813,773)	SNPD	26.473%	(1,009,605)	7.4.1
Schedule M Adjustment	SCHMAT	3	(1,353,789)	SNP	25.599%	(346,551)	7.4.1
Schedule M Adjustment	SCHMAT	3	(2,662,525)	SG	26.070%	(694,129)	7.4.1
Schedule M Adjustment	SCHMDT	3	158,252,176	TAXDEPR	26.410%	41,793,916	7.4.1
Schedule M Adjustment	SCHMDT	3	(7,807,154)	SO	27.173%	(2,121,444)	7.4.1
Schedule M Adjustment	SCHMDT	3	2,582,634	SG	26.070%	673,301	7.4.1
Schedule M Adjustment	SCHMDT	3	507,694	SNP	25.599%	129,962	7.4.1
Schedule M Adjustment	SCHMDT	3	(151,260,232)	GPS	27.173%	(41,102,067)	7.4.1
Deferred Income Tax Expense	41110	3	(76,614,237)	SCHMDEXP	22.648%	(17,351,374)	7.4.1
Deferred Income Tax Expense	41110	3	55,425,777	UT	Situs	-	7.4.1
Deferred Income Tax Expense	41110	3	32,394,831	OR	Situs	32,394,831	7.4.1
Deferred Income Tax Expense	41110	3	4,164,529	ID	Situs	-	7.4.1
DIT Expense - Flowthrough	41110	3	(1,258,830)	OR	Situs	(1,258,830)	7.4.1
Deferred Income Tax Expense	41110	3	1,335,462	SO	27.173%	362,886	7.4.1
Deferred Income Tax Expense	41110	3	8,918,638	CIAC	26.473%	2,360,995	7.4.1
Deferred Income Tax Expense	41110	3	937,677	SNPD	26.473%	248,227	7.4.1
Deferred Income Tax Expense	41110	3	332,851	SNP	25.599%	85,205	7.4.1
Deferred Income Tax Expense	41110	3	654,624	SG	26.070%	170,663	7.4.1
Deferred Income Tax Expense	41010	3	38,908,830	TAXDEPR	26.410%	10,275,703	7.4.1
Deferred Income Tax Expense	41010	3	(1,919,514)	SO	27.173%	(521,591)	7.4.1
Deferred Income Tax Expense	41010	3	634,982	SG	26.070%	165,542	7.4.1
Deferred Income Tax Expense	41010	3	124,825	SNP	25.599%	31,953	7.4.1
Deferred Income Tax Expense	41010	3	(37,189,748)	GPS	27.173%	(10,105,601)	7.4.1

**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, 2022. Updates the related tax depreciation and book depreciation schedule m items and associated deferred income tax expense for the 12 months ended December 31, 2022.

Book Tax Difference		Total Company			STATE Allocation
Description - ADIT	#	Base Period 6/30/2021 - Utility	Adjustment	Adjusted Utility	2020 Protocol
Accelerated Pollution Control Facilities Depreciation	287960	(148,004,159)	148,004,159	0	SG
Accumulated Deferred Income Taxes - YE	287605	(2,745,860,351)	2,745,860,351	0	DITBAL
Accumulated Deferred Income Taxes (CA) - YE	**	0	(67,305,536)	(67,305,536)	CA
Accumulated Deferred Income Taxes (IDU) - YE	**	0	(181,930,228)	(181,930,228)	IDU
Accumulated Deferred Income Taxes (OR) - YE	**	0	(753,603,338)	(753,603,338)	OR
Accumulated Deferred Income Taxes (OTHER) - YE	**	0	(62,185,819)	(62,185,819)	OTHER
Accumulated Deferred Income Taxes (UT) - YE	**	0	(1,372,605,502)	(1,372,605,502)	UT
Accumulated Deferred Income Taxes (WA) - YE	**	0	(189,228,486)	(189,228,486)	WA
Accumulated Deferred Income Taxes (WY) - YE	**	0	(448,663,332)	(448,663,332)	WYP
Rounding	**	0	0	0	DITBAL
		<b>(2,893,864,510)</b>	<b>(181,657,732)</b>	<b>(3,075,522,242)</b>	

Ref. 7.4

Book Tax Difference		Total Company			STATE Allocation
Description - Schedule M Items	#	Base Period 6/30/2021 - Utility	Adjusted Utility	Adjustment	2020 Protocol
<b>Schedule M Additions:</b>					
<b>Permanent Addition:</b>					
Book Depreciation - M&E	105.127	149,749	129,109	(20,640)	SCHMDEXP Ref 7.4
<b>Timing Additions:</b>					
Book Depreciation	105.120 & Other	859,859,922	1,171,469,649	311,609,727	SCHMDEXP Ref 7.4
Book Depreciation - Utah Situs	105.120	225,430,833	-	(225,430,833)	UT Ref 7.4
Book Depreciation - Oregon Situs	105.120	131,758,074	-	(131,758,074)	OR Ref 7.4
Book Depreciation - Idaho	105.120	16,938,209	1	(16,938,208)	IDU Ref 7.4
Book Depreciation - California Situs	105.120	-	-	-	CA Ref 7.4
Book Depreciation - Washington Situs	105.120	-	-	-	WA Ref 7.4
Capitalized Labor & Benefits Costs	105.100	4,075,367	(1,356,297)	(5,431,664)	SO Ref 7.4
CIAC	105.130	121,888,015	85,613,628	(36,274,387)	CIAC Ref 7.4
Reimbursements	105.140	3,813,773	-	(3,813,773)	SNPD Ref 7.4
Avoided Costs	Basis Adj 105.142	72,599,478	71,245,689	(1,353,789)	SNP Ref 7.4
Capitalization of Test Energy	105.146	2,662,525	-	(2,662,525)	SG
<b>Total Schedule M Adds</b>		<b>1,439,175,945</b>	<b>1,327,101,779</b>	<b>(112,074,166)</b>	
<b>Schedule M Deductions:</b>					
Repair Deduction	105.122	154,034,912	156,617,546	2,582,634	SG Ref 7.4
Tax Depreciation	105.125	1,225,252,918	1,383,505,094	158,252,176	TAXDEPR Ref 7.4
Capitalized Depreciation	105.137	7,807,154	-	(7,807,154)	SO Ref 7.4
AFUDC - Debt	105.141 - Debt	38,222,450	34,277,548	(3,944,902)	SNP Ref 7.4
AFUDC - Equity	105.141 - Equity	78,974,277	83,426,873	4,452,596	SNP Ref 7.4
Tax Gain / (Loss) on Prop. Disposition	105.152	119,531,346	2,625,086	(116,906,260)	GPS Ref 7.4
Removal Costs	105.175	78,603,972	44,250,000	(34,353,972)	GPS Ref 7.4
<b>Total Schedule M Deducts</b>		<b>1,702,427,029</b>	<b>1,704,702,147</b>	<b>2,275,118</b>	

Book Tax Difference		Total Company				STATE Allocation
Description - Deferred Income Tax Expense	#	Base Period 6/30/2021 - Utility	Adjusted Utility	Correction to BW	Adjustment	2020 Protocol
<b>Flow-through:</b>						
California	105.115	(327,913)	(254,674)	-	73,239	CA
Idaho	105.115	(415,654)	68,796	-	484,450	IDU
Oregon	105.115	(1,937,044)	(3,195,873)	-	(1,258,830)	OR
Washington	105.115	1,147,123	1,112,730	-	(34,393)	WA
Wyoming - P	105.115	(1,137,075)	(1,571,894)	-	(434,819)	WYP
Wyoming - U	105.115	(1,107,021)	(240,115)	-	866,906	WYU
Utah	105.115	(4,820,168)	1,039,046	-	5,859,215	UT
U FERC	105.115	(187,414)	(251,433)	-	(64,019)	FERC
Other	105.115	(78,578)	24,523	-	103,101	OTHER
<b>Total</b>		<b>(8,863,744)</b>	<b>(3,268,893)</b>	<b>-</b>	<b>5,594,851</b>	

Ref 7.4

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Pro Forma Tax Balances**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Tax:</b>							
Schedule M Adjustment Permanent	SCHMAP	3	(10,558)	SE	25.068%	(2,647)	
	SCHMAP	3	(450,502)	SO	27.173%	(122,415)	
	SCHMDP	3	(5,308,942)	SE	25.068%	(1,330,853)	
	SCHMDP	3	(2,060)	SNP	25.599%	(527)	
Schedule M Adjustment Temporary	SCHMAT	3	(3,553,889)	BADDEBT	48.485%	(1,723,107)	
	SCHMAT	3	(186,149)	CA	Situs	-	
	SCHMAT	3	4,929,707	GPS	27.173%	1,339,553	
	SCHMAT	3	(257,254)	ID	Situs	-	
	SCHMAT	3	(9,433,030)	OR	Situs	(9,433,030)	
	SCHMAT	3	227,964,433	OTHER	0.000%	-	
	SCHMAT	3	(20,056,679)	SE	25.068%	(5,027,835)	
	SCHMAT	3	(170,296)	SG	26.070%	(44,397)	
	SCHMAT	3	(582,468)	SNP	25.599%	(149,103)	
	SCHMAT	3	(15,602,237)	SO	27.173%	(4,239,609)	
	SCHMAT	3	45,715	TROJD	25.891%	11,836	
	SCHMAT	3	(23,121,853)	UT	Situs	-	
	SCHMAT	3	(15,474,052)	WA	Situs	-	
	SCHMAT	3	42,483	WYP	Situs	-	
	SCHMDT	3	317,074	CA	Situs	-	
	SCHMDT	3	(9,002,811)	ID	Situs	-	
	SCHMDT	3	(508,375)	OR	Situs	(508,375)	
	SCHMDT	3	(43,505,410)	OTHER	0.000%	-	
	SCHMDT	3	4,563,366	SE	25.068%	1,143,951	
	SCHMDT	3	(856,231)	SG	26.070%	(223,222)	
	SCHMDT	3	(969,539)	SNPD	26.473%	(256,662)	
	SCHMDT	3	110,880,326	SO	27.173%	30,129,602	
	SCHMDT	3	22,934,894	UT	Situs	-	
	SCHMDT	3	(249,911)	WA	Situs	-	
	SCHMDT	3	4,802,347	WYP	Situs	-	
Current Federal Tax Credits	40910	3	28,220	SE	25.068%	7,074	
	40910	3	1,659	SO	27.173%	451	
State Income Tax	40911	3	10,953,263	OTHER	0.000%	-	

**Description of Adjustment:**

This adjustment normalizes the Base period Schedule M to an estimated proforma level of expense for the CY December 2023 Test period.

PacifiCorp  
Oregon General Rate Case - December 2023  
(cont.) Pro Forma Tax Balances

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Tax:</b>							
Deferred Tax Expense Debit	41010	3	77,958	CA	Situs	-	
	41010	3	(2,213,484)	ID	Situs	-	
	41010	3	(124,992)	OR	Situs	(124,992)	
	41010	3	(10,696,500)	OTHER	0.000%	-	
	41010	3	1,121,977	SE	25.068%	281,259	
	41010	3	(210,518)	SG	26.070%	(54,883)	
	41010	3	(238,377)	SNPD	26.473%	(63,105)	
	41010	3	27,261,704	SO	27.173%	7,407,845	
	41010	3	5,638,911	UT	Situs	-	
	41010	3	(61,445)	WA	Situs	-	
	41010	3	1,180,733	WYP	Situs	-	
Deferred Tax Expense Credit	41110	3	873,780	BADDEBT	48.485%	423,653	
	41110	3	45,768	CA	Situs	-	
	41110	3	63,250	ID	Situs	-	
	41110	3	-	FERC	0.000%	-	
	41110	3	(1,212,047)	GPS	27.173%	(329,351)	
	41110	3	2,319,262	OR	Situs	2,319,262	
	41110	3	(57,946,167)	OTHER	0.000%	-	
	41110	3	4,931,256	SE	25.068%	1,236,174	
	41110	3	1,152,362	SG	26.070%	300,425	
	41110	3	143,209	SNP	25.599%	36,659	
	41110	3	3,836,059	SO	27.173%	1,042,375	
	41110	3	(11,240)	TROJD	25.891%	(2,910)	
	41110	3	5,684,878	UT	Situs	-	
	41110	3	3,804,544	WA	Situs	-	
	41110	3	(10,445)	WYP	Situs	-	
	41110	3	-	WYU	Situs	-	
ITC Amortization	41140	3	647,635	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 CY December 2023 Test period.

PacifiCorp  
Oregon General Rate Case - December 2023  
(cont.) Pro Forma Tax Balances

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Tax:</b>							
ADIT Balance 190	190	3	287,036	BADDEBT	48.485%	139,170	
	190	3	46,121	CA	Situs	-	
	190	3	(39,314)	ID	Situs	-	
	190	3	(142,097)	OR	Situs	(142,097)	
	190	3	(5,454,037)	OTHER	0.000%	-	
	190	3	(943,514)	SE	25.068%	(236,521)	
	190	3	(577,551)	SG	26.070%	(150,570)	
	190	3	(16,485,532)	SO	27.173%	(4,479,627)	
	190	3	(9,977)	TROJD	25.891%	(2,583)	
	190	3	(1,152,438)	UT	Situs	-	
	190	3	(7,466,690)	WA	Situs	-	
	190	3	6,492	WYP	Situs	-	
	190	3	855,199	SNPD	26.473%	226,393	
ADIT Balance 282	282	3	(8,598,628)	OTHER	0.000%	-	
	282	3	(78,185)	SE	25.068%	(19,600)	
	282	3	(11,946)	SO	27.173%	(3,246)	
	282	3	77,911	SNP	25.599%	19,944	
	282	3	1,048,227	UT	Situs	-	
	282	3	348,444	WYP	Situs	-	
ADIT Balance 283	283	3	769,352	CA	Situs	-	
	283	3	(36,304)	GPS	27.173%	(9,865)	
	283	3	(583,741)	ID	Situs	-	
	283	3	325,163	OR	Situs	325,163	
	283	3	(6,901,536)	OTHER	0.000%	-	
	283	3	515,387	SE	25.068%	129,198	
	283	3	(269,601)	SG	26.070%	(70,286)	
	283	3	70,997	SNP	25.599%	18,174	
	283	3	9,428,836	SO	27.173%	2,562,105	
	283	3	360,210	UT	Situs	-	
	283	3	(57,404)	WA	Situs	-	
	283	3	3,362,655	WYP	Situs	-	
	283	3	13,442	WYU	Situs	-	
ADIT Balance 255	255	3	(118,720)	UT	Situs	-	
	255	3	17,542	SG	26.070%	4,573	
	255	3	7,225	ID	Situs	-	

**Description of Adjustment:**

This adjustment normalizes the Base period Accumulated Deferred Income Tax Balances to an proforma level of a thirteen-month average rate base balance for the CY December 2023 Test period.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Wyoming Wind Generation Tax**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Tax:</b>							
Taxes Other Than Income	408	3	88,230	SG	26.070%	23,002	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 privilege of producing electricity from wind resources in the state of Wyoming. The tax is on the production of any electricity produced from wind resources for sale or trade on or after January 1, 2012, and is to be paid by the entity 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 2023  
Wyoming Wind Generation Tax  
Oregon**

<b>Wind Plant</b>	<b>2023 NPC MWH Production (b)</b>	<b>Tax Begins</b>	<b>2023 \$/MWH Tax</b>
Foote Creek (a)	-	3/24/2024	-
Glenrock I Wind Plant	369,733	1/1/2012	369,733
Glenrock III Wind Plant	136,868	1/1/2012	136,868
Seven Mile Hill Wind Plant	417,048	1/1/2012	417,048
Seven Mile Hill II Wind Plant	87,428	1/1/2012	87,428
Rolling Hills Wind Plant	-	1/17/2012	-
High Plains Wind Plant	382,404	9/1/2012	382,404
McFadden Ridge	116,545	9/1/2012	116,545
Dunlap	476,749	10/1/2013	476,749
Cedar Springs Wind II (a)	77,411	12/4/2023	77,411
Ekola Flats Wind (a)	108,649	12/1/2023	108,649
TB Flats Wind (a)	111,117	12/1/2023	111,117
TB Flats Wind II (a)	36,627	12/22/2023	36,627
<b>Total WY Wind MWH</b>	<b><u>2,320,579</u></b>		<b><u>2,320,579</u></b>
June 2021 Base Period			2,232,349
ProForma Adjustment - December 2023			<b><u>88,230</u></b> <b>Ref 7.6</b>

(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. Rolling Hills is not included in this calculation because Oregon does not include Rolling Hills in rates.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**AFUDC - Equity**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b> AFUDC - Equity	419	1	(4,260,964)	SNP	25.599%	(1,090,745)	

**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**  
**Oregon General Rate Case - December 2023**  
**TCJA EDIT Adjustment**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustments to Rate Base:</b>							
Reg Liab - Protected PP&E EDIT - OR	254	1	27,572,240	OR	Situs	27,572,240	
<b>Adjustments to Tax:</b>							
DTA - Reg Liab - Protected PP&E EDIT - OR	190	1	(6,779,076)	OR	Situs	(6,779,076)	
DTL PMI PP&E - Protected Property EDIT	282	1	1,982,626	SE	25.068%	497,007	
Protected PP&E RSGM Amortization - OR	41110	1	11,298,487	OR	Situs	11,298,487	

**Description of Adjustment:**

This adjustment reflects the level of protected property EDIT amortization and adjusts the rate base for the test period. This adjustment also reflects an adjustment to RSGM amortization to reflect the incremental coal lives adjustment proposed in the current GRC.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Oregon Corporate Activity Tax & Metro BIT**

<b>Adjustment to Expense:</b>	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
Oregon Corporate Activity Tax	40911	3	5,601,037	OR	Situs	5,601,037	7.9.1
Metro Business Income Tax	40911	3	244,599	OR	Situs	244,599	7.9.2

**Description of Adjustment:**

This adjustment is to include the Oregon Corporate Activity Tax and Metro Business Income Tax in base rates effective January 1, 2023.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Oregon Corporate Activity Tax**

	<b>OR CAT</b>	
Jun-21 12 months Oregon Corporate Activity Tax - Base Period	-	
Dec-23 12 months Oregon Corporate Activity Tax - 2023 Forecast	<u>5,601,037</u>	
Total	<u><u>5,601,037</u></u>	
Adjustment to Account 40911	<u><u>5,601,037</u></u>	<b>Ref. 7.9</b>

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Oregon Corporate Activity Tax & Metro BIT**

		<b>Metro Business Income Tax</b>	
Jun-21	12 months	Metro Business Income Tax - Base Period	-
Dec-23	12 months	Metro Business Income Tax - 2023 Forecast	244,599
		Total	<u>244,599</u>
			<u>244,599</u>
		Adjustment to Account 40911	<u>244,599</u> <b>Ref. 7.9</b>

Tab \* - DSfV1SeW

**PacifiCorp**  
**Oregon General Rate Case – December 2023**  
**Rate Base Adjustment Index**

The Company used year-end rate base as of June 2021 as the starting point for establishing the adjustments made to the test period. Test period electric plant in service is reflected using December 2020 ending balances. Other rate base components are reflected using a December 2023 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 Pro Forma Plant Additions & Retirements
- 8.5 Customer Advances for Construction
- 8.6 Regulatory Assets & Liabilities Amortization
- 8.7 FERC 105 (PHFU) Adjustment
- 8.8 Pension and Other Post-retirement Balances Removal
- 8.9 Remove Rolling Hills
- 8.10 Deer Creek Mine Adjustment
- 8.11 Emissions Control Investment Adjustment
- 8.12 Transmission Project Adjustment
- 8.13 Cholla Unit 4 Retirement
- 8.14 Wind Project Deferrals Amortization
- 8.15 Miscellaneous Rate Base
- 8.16 Carbon Plant Closure
- 8.17 Labor Day Wildfire Restoration

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Tab 8 Adjustment Summary**

	8.2	8.3	8.4	8.5	8.6	8.7
	Trapper Mine Rate Base	Jim Bridger Mine Rate Base	Pro Forma Plant Additions and Retirements	Customer Advances for Construction	Regulatory Assets & Liabilities Amortization	FERC 105 (PHFU) Adjustment
Total Adjustments						
1 Operating Revenues:						
2 General Business Revenues	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-
5 Other Operating Revenues	2,235,548	-	-	-	2,235,548	-
6 Total Operating Revenues	2,235,548	-	-	-	2,235,548	-
7						
8 Operating Expenses:						
9 Steam Production	(13,042,384)	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-
12 Other Power Supply	(297,478)	-	-	-	-	-
13 Transmission	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	(980,746)	-	-	-	-	-
19						
20 Total O&M Expenses	(14,320,608)	-	-	-	-	-
21						
22 Depreciation	(3,093,033)	-	-	-	-	-
23 Amortization	2,373,437	-	-	-	(3,080,765)	-
24 Taxes Other Than Income	-	-	-	-	-	-
25 Income Taxes - Federal	5,625,758	70,898	(42,235)	(788,947)	(21,333)	1,490,380
26 Income Taxes - State	1,274,079	16,056	(9,565)	(178,675)	(4,831)	337,530
27 Income Taxes - Def Net	(3,623,440)	(95,204)	-	(1,036,727)	-	(515,499)
28 Investment Tax Credit Adj.	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-
30						
31 Total Operating Expenses:	(11,763,808)	(8,250)	(51,800)	(2,004,348)	(26,164)	(1,768,354)
32						
33 Operating Rev For Return:	13,999,357	8,250	51,800	2,004,348	26,164	4,003,902
34						
35 Rate Base:						
36 Electric Plant In Service	285,403,652	2,044,862	10,218,169	389,382,973	-	-
37 Plant Held for Future Use	(9,657,872)	-	-	-	-	(9,657,872)
38 Misc Deferred Debits	(126,476,526)	-	-	-	-	-
39 Elec Plant Acq Adj	(1,051,423)	-	-	-	(1,051,423)	-
40 Nuclear Fuel	(7,786,953)	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-
42 Fuel Stock	(7,313,106)	-	-	-	-	-
43 Material & Supplies	(1,392,651)	-	-	-	-	-
44 Working Capital	(609,953)	(538,990)	(490)	(9,146)	(247)	17,277
45 Weatherization Loans	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	131,115,168	1,505,872	10,217,680	389,373,827	(247)	(1,034,146)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(3,746,161)	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-
53 Accum Def Income Tax	40,243,899	98,774	(142,084)	494,791	-	-
54 Unamortized ITC	-	-	-	-	-	-
55 Customer Adv For Const	5,089,393	-	-	-	5,089,393	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	16,186,182	-	-	-	-	-
58						
59 Total Rate Base Deductions	57,773,313	98,774	(142,084)	494,791	5,089,393	-
60						
61 Total Rate Base:	188,888,481	1,604,646	10,075,595	389,868,618	5,089,146	(1,034,146)
62						
63 Return on Rate Base	0.136%	-0.002%	-0.010%	-0.342%	-0.004%	0.092%
64						
65 Return on Equity	0.260%	-0.003%	-0.019%	-0.654%	-0.008%	0.175%
66						
67 TAX CALCULATION:						
68 Operating Revenue	17,275,753	-	-	-	5,316,314	-
69 Other Deductions	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-
71 Interest	3,949,681	33,553	210,682	8,152,200	106,415	(21,624)
72 Schedule "M" Additions	9,745,647	387,218	-	3,695,103	-	5,049,553
73 Schedule "M" Deductions	(4,991,685)	-	-	(521,533)	-	2,952,912
74 Income Before Tax	28,063,404	353,664	(210,682)	(3,935,563)	(106,415)	7,434,579
75						
76 State Income Taxes	1,274,079	16,056	(9,565)	(178,675)	(4,831)	337,530
77 Taxable Income	26,789,326	337,608	(201,117)	(3,756,888)	(101,583)	7,097,049
78						
79 Federal Income Taxes + Other	5,625,758	70,898	(42,235)	(788,947)	(21,333)	1,490,380
APPROXIMATE PRICE CHANGE	(515,983)	147,351	925,222	35,800,847	467,326	(5,591,443)

**PacifiCorp**  
**Oregon General Rate Case - December 202:**  
**Tab 8 Adjustment Summary**

	8.8	8.9	8.10	8.11	8.12	8.13	8.14
	Pension and Other Post-retirement Balances Removal	Remove Rolling Hills	Deer Creek Mine Adjustment	Emissions Control Investment Adjustment	Transmission Project Adjustment	Cholla Unit 4 Retirement	Wind Project Deferrals Amortization
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	-	-	(9,223,534)	-	-	(3,818,850)	-
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-
12 Other Power Supply	-	(297,478)	-	-	-	-	-
13 Transmission	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	-	(117,259)	806,229	(1,669,716)	-	-	-
19							
20 Total O&M Expenses	-	(414,737)	(8,417,305)	(1,669,716)	-	(3,818,850)	-
21							
22 Depreciation	-	-	-	(84,762)	-	-	-
23 Amortization	-	-	-	-	-	762,619	6,397,077
24 Taxes Other Than Income	-	-	-	-	-	-	-
25 Income Taxes - Federal	310,979	837,440	834,534	345,714	598	587,745	-
26 Income Taxes - State	70,428	189,657	188,999	78,295	135	133,108	-
27 Income Taxes - Def Net	-	(707,111)	1,100,367	12,584	-	38,516	(1,572,828)
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-
30							
31 Total Operating Expenses:	381,407	(94,750)	(6,293,405)	(1,317,887)	734	(2,296,863)	4,824,249
32							
33 Operating Rev For Return:	(381,407)	94,750	6,293,405	1,317,887	(734)	2,296,863	(4,824,249)
34							
35 Rate Base:							
36 Electric Plant In Service	-	(50,873,419)	-	(1,212,256)	(182,000)	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-
38 Misc Deferred Debits	(110,544,888)	-	(11,013,202)	-	-	309,565	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-
40 Nuclear Fuel	(7,786,953)	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	(1,392,651)	-
44 Working Capital	3,605	5,788	(69,886)	(11,774)	7	(29,282)	-
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	(118,328,235)	(50,867,631)	(11,083,088)	(1,224,030)	(181,993)	(1,112,368)	-
49							
50 Rate Base Deductions:							
51 Accum Prov For Deprec	-	(4,661,784)	-	84,762	28,512	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	23,914,636	13,118,713	507,306	122,816	10,751	(433,098)	-
54 Unamortized ITC	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	20,225,559	-	-	-	-	-	-
58							
59 Total Rate Base Deductions	44,140,194	8,456,929	507,306	207,579	39,263	(433,098)	-
60							
61 Total Rate Base:	(74,188,041)	(42,410,702)	(10,575,782)	(1,016,451)	(142,730)	(1,545,466)	-
62							
63 Return on Rate Base	0.062%	0.044%	0.158%	0.032%	0.000%	0.055%	-0.113%
64							
65 Return on Equity	0.119%	0.084%	0.302%	0.061%	0.000%	0.106%	-0.216%
66							
67 TAX CALCULATION:							
68 Operating Revenue	-	414,737	8,417,305	1,754,479	-	3,056,231	(6,397,077)
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	(1,551,281)	(886,813)	(221,141)	(21,254)	(2,985)	(32,316)	-
72 Schedule "M" Additions	-	19	(5,541,906)	(84,763)	-	(156,655)	6,397,077
73 Schedule "M" Deductions	-	(2,875,900)	(1,066,432)	(33,581)	-	-	-
74 Income Before Tax	1,551,281	4,177,468	4,162,972	1,724,551	2,985	2,931,891	-
75							
76 State Income Taxes	70,428	189,657	188,999	78,295	135	133,108	-
77 Taxable Income	1,480,853	3,987,811	3,973,973	1,646,256	2,849	2,798,784	-
78							
79 Federal Income Taxes + Other	310,979	837,440	834,534	345,714	598	587,745	-
APPROXIMATE PRICE CHANGE	(6,812,538)	(4,323,307)	(9,673,700)	(1,907,273)	(13,107)	(3,301,717)	6,613,853



**PacifiCorp**  
**Oregon General Rate Case - December 202:**  
**Tab 8 Adjustment Summary**

	8.15	8.16	8.17
	Miscellaneous Rate Base	Carbon Plant Closure	Remove Labor Day Wildfire Restoration
1 Operating Revenues:			
2 General Business Revenues	-	-	-
3 Interdepartmental	-	-	-
4 Special Sales	-	-	-
5 Other Operating Revenues	-	-	-
6 Total Operating Revenues	-	-	-
7			
8 Operating Expenses:			
9 Steam Production	-	-	-
10 Nuclear Production	-	-	-
11 Hydro Production	-	-	-
12 Other Power Supply	-	-	-
13 Transmission	-	-	-
14 Distribution	-	-	-
15 Customer Accounting	-	-	-
16 Customer Service & Info	-	-	-
17 Sales	-	-	-
18 Administrative & General	-	-	-
19			
20 Total O&M Expenses	-	-	-
21			
22 Depreciation	-	(3,008,271)	-
23 Amortization	-	(1,705,494)	-
24 Taxes Other Than Income	-	-	-
25 Income Taxes - Federal	49,174	618,693	1,291,635
26 Income Taxes - State	11,137	140,117	292,520
27 Income Taxes - Def Net	-	419,323	(1,266,861)
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	-
30			
31 Total Operating Expenses:	60,311	(3,535,633)	317,293
32			
33 Operating Rev For Return:	(60,311)	3,535,633	(317,293)
34			
35 Rate Base:			
36 Electric Plant In Service	-	-	(63,974,678)
37 Plant Held for Future Use	-	-	-
38 Misc Deferred Debits	(4,418,666)	(809,336)	-
39 Elec Plant Acq Adj	-	-	-
40 Nuclear Fuel	-	-	-
41 Prepayments	-	-	-
42 Fuel Stock	(7,313,106)	-	-
43 Material & Supplies	-	-	-
44 Working Capital	570	7,172	14,973
45 Weatherization Loans	-	-	-
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	(11,731,202)	(802,164)	(63,959,704)
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	-	-	802,349
52 Accum Prov For Amort	-	-	-
53 Accum Def Income Tax	-	1,111,185	1,440,110
54 Unamortized ITC	-	-	-
55 Customer Adv For Const	-	-	-
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	-	(4,039,377)	-
58			
59 Total Rate Base Deductions	-	(2,928,192)	2,242,459
60			
61 Total Rate Base:	(11,731,202)	(3,730,356)	(61,717,245)
62			
63 Return on Rate Base	0.011%	0.087%	0.058%
64			
65 Return on Equity	0.020%	0.166%	0.111%
66			
67 TAX CALCULATION:			
68 Operating Revenue	-	4,713,765	-
69 Other Deductions	-	-	-
70 Interest (AFUDC)	-	-	-
71 Interest	(245,301)	(78,002)	(1,290,515)
72 Schedule "M" Additions	-	-	-
73 Schedule "M" Deductions	-	1,705,494	(5,152,646)
74 Income Before Tax	245,301	3,086,273	6,443,161
75			
76 State Income Taxes	11,137	140,117	292,520
77 Taxable Income	234,164	2,946,156	6,150,641
78			
79 Federal Income Taxes + Other	49,174	618,693	1,291,635
APPROXIMATE PRICE CHANGE	(1,077,253)	(5,216,054)	(5,667,370)

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Cash Working Capital**

PAGE 8.1

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Cash Working Capital	CWC	3	(107,814)	OR	Situs	(107,814)	Below
<b>Adjustment Detail:</b>							
Cash Working Capital June 2021 - Unadjusted			30,454,966			8,611,296	2.28
Cash Working Capital December 2023 - Normalized			29,774,416			8,503,482	2.28
Adjustment:			<u>(680,550)</u>			<u>(107,814)</u>	

**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 2015 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, 2023**

	<u>Total</u>	<u>California</u>	<u>Oregon</u>	<u>Washington</u>	<u>Wyoming</u>	<u>Wy-PPL</u>	<u>Utah</u>	<u>Idaho</u>	<u>Wy-UPL</u>	<u>FERC</u>
Lead/Lag Study as of 12/15										
Revenue Lag Days	41.52	41.17	40.25	41.27	37.72	37.72	40.88	37.54	37.72	35.62
Expense Lag Days	35.72	40.25	36.80	35.20	36.83	36.83	36.81	36.86	36.83	35.10
Net Lag Days	5.80	0.92	3.45	6.07	0.89	0.89	4.07	0.68	0.89	0.53
O&M Expense	3,121,551,077	58,913,813	872,542,561	230,326,389	424,577,540	353,331,962	1,345,821,963	188,541,838	71,245,578	826,973
Taxes Other than Income	234,822,593	5,662,440	84,171,808	15,559,791	28,608,688	24,024,486	88,944,546	11,833,351	4,584,202	41,969
Federal Income Tax	(142,051,017)	(374,862)	(61,296,146)	(9,212,286)	(33,776,153)	(25,502,958)	(34,028,758)	(5,570,976)	(8,273,195)	2,208,163
State Income Tax	19,938,979	589,852	4,230,426	1,518,468	(1,122,384)	(367,390)	12,708,855	1,500,217	(754,994)	513,545
Total	3,234,261,632	64,791,242	899,648,649	238,192,363	418,287,692	351,486,101	1,413,446,606	196,304,430	66,801,591	3,590,650
Divided by Days in Year	365	365	365	365	365	365	365	365	365	365
Avg. Daily Cost of Service	8,860,991	177,510	2,464,791	652,582	1,145,994	962,976	3,872,456	537,820	183,018	9,837
Net Lag Days	5.80	0.92	3.45	6.07	0.89	0.89	4.07	0.68	0.89	0.53
Cash Working Capital	<b>29,774,416</b>	163,168	<b>8,503,482</b>	3,961,172	1,018,899	856,178	15,754,630	367,858	162,721	5,206
	<b>Ref. 8.1</b>		<b>Ref. 8.1</b>							

**PacifiCorp  
Oregon General Rate Case - December 2023  
Trapper Mine Rate Base**

PAGE 8.2

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Other Tangible Property	399	1	9,334,515	SE	25.068%	2,339,989	Below
Other Tangible Property	399	3	<u>(1,177,299)</u>	SE	25.068%	<u>(295,127)</u>	Below
			<u>8,157,216</u>			<u>2,044,862</u>	Below
Final Reclamation Liability	2533	3	(2,153,378)	SE	25.068%	(539,812)	Below
<b>Adjustment to Tax:</b>							
Schedule M Adj - Reclamation Liab	SCHMAT	3	1,544,661	SE	25.068%	387,218	8.2.2
Deferred Income Tax Expense	41110	3	(379,780)	SE	25.068%	(95,204)	8.2.2
Accumulated Def Inc Tax Balance	190	3	394,020	SE	25.068%	98,774	8.2.2
<b>Adjustment Detail</b>							
<u>Other Tangible Property</u>							
June 2021 End of Period Balance			9,334,515				8.2.1
December 2022 End of Period Balance			<u>8,157,216</u>				8.2.1
Adjust to December 2022 End of Period Balance			<u>(1,177,299)</u>				Above
<u>Final Reclamation Liability</u>							
June 2021 12 Mth. Average			(7,150,412)				8.2.2
December 2022 12 Mth. Average			<u>(9,303,790)</u>				8.2.2
Adjust to December 2022 12 Mth. Average			<u>(2,153,378)</u>				Above

**Description of Adjustment:**

The Company owns a 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. This adjustment reflects net plant to recognize the depreciation of the investment over time. This adjustment also walks forward the Reclamation Liability to December 2022. 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 2023  
Trapper Mine Rate Base

DESCRIPTION	Jun-21 Actual	Jan-22 Forecast	Feb-22 Forecast	Mar-22 Forecast	Apr-22 Forecast	May-22 Forecast	Jun-22 Forecast	Jul-22 Forecast	Aug-22 Forecast	Sep-22 Forecast	Oct-22 Forecast	Nov-22 Forecast	Dec-22 Forecast
<b>Property, Plant, and Equipment</b>													
Lands and Leases	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984
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
Equipment and Facilities	126,096,849	127,016,467	127,445,821	127,445,821	127,524,353	126,060,805	126,096,849	126,126,654	126,156,672	127,016,467	127,016,467	127,016,467	127,016,467
Total Property, Plant, and Equipment	146,680,648	147,600,266	148,029,620	148,029,620	148,108,152	146,644,604	146,680,648	146,710,453	146,740,471	147,600,266	147,600,266	147,600,266	147,600,266
Accumulated Depreciation	(121,309,323)	(123,314,154)	(123,596,037)	(123,877,920)	(124,159,803)	(124,441,687)	(124,723,570)	(125,005,453)	(125,287,336)	(125,569,219)	(125,851,102)	(126,132,985)	(126,414,868)
<b>Total Property, Plant, and Equipment</b>	<b>25,371,325</b>	<b>24,286,112</b>	<b>24,433,583</b>	<b>24,151,700</b>	<b>23,948,349</b>	<b>22,202,917</b>	<b>21,957,078</b>	<b>21,705,000</b>	<b>21,453,135</b>	<b>22,031,047</b>	<b>21,749,164</b>	<b>21,467,281</b>	<b>21,185,398</b>
<b>Other</b>													
Inventories	5,855,454	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000
Prepaid Expenses	148,766	136,364	122,727	109,091	95,455	81,818	68,182	54,545	40,909	27,273	13,636	0	150,000
Restricted Funds: Self-bonding for Black Lung	657,793	657,793	657,793	657,793	657,793	657,793	657,793	657,793	657,793	657,793	657,793	657,793	657,793
Deferred GE Royalty Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
Advance Royalty - State 206-13	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total Other</b>	<b>6,662,013</b>	<b>6,794,157</b>	<b>6,780,520</b>	<b>6,766,884</b>	<b>6,753,248</b>	<b>6,739,611</b>	<b>6,725,975</b>	<b>6,712,338</b>	<b>6,698,702</b>	<b>6,685,066</b>	<b>6,671,429</b>	<b>6,657,793</b>	<b>6,807,793</b>
Total Rate Base	32,033,338	31,080,269	31,214,103	30,918,584	30,701,596	28,942,529	28,683,053	28,417,339	28,151,837	28,716,113	28,420,593	28,125,074	27,993,191
<b>PacifiCorp Share (29.14%)</b>	<b>9,334,515</b>	<b>9,056,790</b>	<b>9,095,790</b>	<b>9,009,675</b>	<b>8,946,445</b>	<b>8,433,853</b>	<b>8,358,242</b>	<b>8,280,812</b>	<b>8,203,445</b>	<b>8,367,875</b>	<b>8,281,761</b>	<b>8,195,646</b>	<b>8,157,216</b>

June 2021 End of Period Balance	<u>9,334,515</u>	Ref 8.2
December 2022 End of Period Balance	<u>8,157,216</u>	Ref 8.2

PacifiCorp  
Oregon General Rate Case - December 2023  
Trapper Mine  
Final Reclamation Liability

Actuals

Description:	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
Final Reclamation Liability	(6,874,217)	(6,886,120)	(6,904,116)	(6,922,709)	(6,939,870)	(6,961,463)	(7,139,466)	(7,199,003)	(7,334,523)	(7,420,190)	(7,550,403)	(7,672,867)

Forecast

Description:	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Final Reclamation Liability	(8,557,557)	(8,693,236)	(8,828,915)	(8,964,594)	(9,100,272)	(9,235,951)	(9,371,630)	(9,507,309)	(9,642,987)	(9,778,666)	(9,914,345)	(10,050,024)

End of Period Balance:  
 June 2021 12 Mth. Average (7,150,412)  
 December 2022 12 Mth. Average (9,303,790)  
 Adjustment to Rate Base (2,153,378) Ref 8.2

Adjustments for Tax:	
Change in Liability Account Balance:	
Schedule M Add - Pro Forma	2,377,157
Schedule M Add - Base Period	832,496
<b>Adjustment needed</b>	<u>1,544,661</u> Ref 8.2
Def Inc Tax Exp - Pro Forma	(584,462)
Def Inc Tax Exp - Base Period	(204,682)
<b>Adjustment needed</b>	<u>(379,780)</u> Ref 8.2

ADIT Adjustment for Tax:

Actuals Account 287216 (FERC Account 190) M#605.715

Description:	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
Trapper Mine Contract Obligation	1,672,103	1,677,591	1,680,518	1,683,317	1,687,889	1,692,108	1,697,901	1,741,666	1,756,304	1,772,076	1,793,138	1,825,154	1,876,786

Forecast

Description:	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Trapper Mine Contract Obligation	2,070,654	2,104,012	2,137,371	2,170,730	2,204,089	2,237,448	2,270,806	2,304,165	2,337,524	2,370,883	2,404,242	2,437,600	2,470,959

End of Period Balance:  
 Base Period June 2021 End of Period 1,876,786  
 December 2022 13 Mth. Average 2,270,806  
 Adjustment to Rate Base 394,020 Ref 8.2

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Jim Bridger Mine Rate Base**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Other Tangible Property	399	1	70,453,393	SE	25.068%	17,661,352	Below
Other Tangible Property	399	3	(29,691,808)	SE	25.068%	(7,443,183)	Below
			<u>40,761,585</u>			<u>10,218,169</u>	
<b>Adjustment to Tax:</b>							
Accumulated Def Inc Tax Balance	190	3	(566,792)	SE	25.068%	(142,084)	8.3.2
<b>Adjustment Detail</b>							
June 2021 End of Period Balance			70,453,393				8.3.1
December 2022 End of Period Balance			40,761,585				8.3.1
Adjustment to December 2022 Balance			<u>(29,691,808)</u>				

**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 2023  
Bridger Mine Rate Base  
End of Period  
(000's)

<b>Bridger Total</b>	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
<b>Description</b>	<b>Jun-20</b>	<b>Jul-20</b>	<b>Aug-20</b>	<b>Sep-20</b>	<b>Oct-20</b>	<b>Nov-20</b>	<b>Dec-20</b>	<b>Jan-21</b>	<b>Feb-21</b>	<b>Mar-21</b>	<b>Apr-21</b>	<b>May-21</b>	<b>Jun-21</b>
1 Structure, Equipment, Mine Dev.	443,268	443,915	444,291	444,462	444,522	444,453	444,566	444,115	444,555	445,008	445,008	437,569	437,572
2 Materials & Supplies	14,681	14,271	13,913	13,670	13,464	13,151	13,081	12,668	12,101	12,189	11,687	11,085	10,760
4 Pit Inventory	40,522	39,386	35,477	29,754	29,033	27,057	27,609	24,940	27,571	33,051	37,777	39,455	36,350
5 Deferred Long Wall Costs	4,801	3,967	4,072	4,512	4,549	4,733	5,179	4,912	4,502	4,381	4,249	3,637	3,789
6 Reclamation Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Accumulated Depreciation	(364,463)	(366,892)	(369,293)	(371,032)	(373,040)	(375,179)	(377,270)	(379,094)	(381,388)	(383,865)	(386,036)	(380,979)	(382,790)
8 Bonus Bid / Lease Payable	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>TOTAL RATE BASE</b>	<b>138,809</b>	<b>134,647</b>	<b>128,459</b>	<b>121,366</b>	<b>118,528</b>	<b>114,215</b>	<b>113,166</b>	<b>107,541</b>	<b>107,342</b>	<b>110,764</b>	<b>112,687</b>	<b>110,767</b>	<b>105,680</b>
<b>PacifiCorp Share (66.67%)</b>	<b>92,539</b>	<b>89,765</b>	<b>85,639</b>	<b>80,911</b>	<b>79,018</b>	<b>76,143</b>	<b>75,444</b>	<b>71,694</b>	<b>71,561</b>	<b>73,842</b>	<b>75,124</b>	<b>73,845</b>	<b>70,453</b>

<b>Bridger Total</b>	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
<b>Description</b>	<b>Dec-21</b>	<b>Jan-22</b>	<b>Feb-22</b>	<b>Mar-22</b>	<b>Apr-22</b>	<b>May-22</b>	<b>Jun-22</b>	<b>Jul-22</b>	<b>Aug-22</b>	<b>Sep-22</b>	<b>Oct-22</b>	<b>Nov-22</b>	<b>Dec-22</b>
1 Structure, Equipment, Mine Dev.	443,465	443,592	443,613	443,635	444,271	444,293	445,687	445,708	445,885	446,986	447,662	447,683	448,089
2 Materials & Supplies	13,998	9,860	9,844	9,827	9,810	9,794	9,566	9,549	9,533	9,516	9,499	9,483	9,466
4 Pit Inventory	27,860	27,067	22,768	21,686	23,580	23,898	24,673	23,393	20,794	18,845	17,930	15,321	8,579
5 Deferred Long Wall Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
6 Reclamation Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Accumulated Depreciation	(396,067)	(396,807)	(397,524)	(398,241)	(398,965)	(399,717)	(400,459)	(401,198)	(401,939)	(402,696)	(403,470)	(404,238)	(404,992)
8 Bonus Bid / Lease Payable	-	-	-	-	-	-	-	-	-	-	-	-	-
<b>TOTAL RATE BASE</b>	<b>89,256</b>	<b>83,713</b>	<b>78,701</b>	<b>76,908</b>	<b>78,697</b>	<b>78,268</b>	<b>79,467</b>	<b>77,453</b>	<b>74,272</b>	<b>72,650</b>	<b>71,621</b>	<b>68,248</b>	<b>61,142</b>
<b>PacifiCorp Share (66.67%)</b>	<b>59,504</b>	<b>55,809</b>	<b>52,467</b>	<b>51,272</b>	<b>52,464</b>	<b>52,179</b>	<b>52,978</b>	<b>51,635</b>	<b>49,515</b>	<b>48,434</b>	<b>47,747</b>	<b>45,499</b>	<b>40,762</b>

June 2021 - End of Period Balance	70,453	Ref 8.3
December 2022 - End of Period Balance	40,762	Ref 8.3



PacifiCorp  
Oregon General Rate Case - December 2023  
Bridger Mine Rate Base  
End of Period  
(000's)

	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	12/1/2022
<b>Materials &amp; Supplies:</b>													
Obsolete Reserve - Surface	(319,053)	(335,720)	(352,386)	(369,053)	(385,720)	(402,386)	(419,053)	(435,720)	(452,386)	(469,053)	(485,720)	(502,386)	(519,053)
Obsolete Reserve - Underground	(3,362,169)	(3,362,169)	(3,362,169)	(3,362,169)	(3,362,169)	(3,362,169)	-	-	-	-	-	-	-
<b>Total Obsolete Reserves</b>	<b>(3,681,222)</b>	<b>(3,697,889)</b>	<b>(3,714,555)</b>	<b>(3,731,222)</b>	<b>(3,747,889)</b>	<b>(3,764,555)</b>	<b>(419,053)</b>	<b>(435,720)</b>	<b>(452,386)</b>	<b>(469,053)</b>	<b>(485,720)</b>	<b>(502,386)</b>	<b>(519,053)</b>
<b>PacifiCorp's 2/3 share:</b>													
Obsolete Reserve - Surface	(212,702)	(223,813)	(234,924)	(246,035)	(257,146)	(268,258)	(279,369)	(290,480)	(301,591)	(312,702)	(323,813)	(334,924)	(346,035)
Obsolete Reserve - Underground	(2,241,446)	(2,241,446)	(2,241,446)	(2,241,446)	(2,241,446)	(2,241,446)	-	-	-	-	-	-	-
<b>Total of PacifiCorp's share of Obsolete Reserves</b>	<b>(2,454,148)</b>	<b>(2,465,259)</b>	<b>(2,476,370)</b>	<b>(2,487,481)</b>	<b>(2,498,592)</b>	<b>(2,509,704)</b>	<b>(279,369)</b>	<b>(290,480)</b>	<b>(301,591)</b>	<b>(312,702)</b>	<b>(323,813)</b>	<b>(334,924)</b>	<b>(346,035)</b>
<b>ADIT 190 EOP Balance at June 30, 2021</b>	<b>651,870</b>	<b>Per Tax Model (Account 287938, M#205.205)</b>											
<b>ADIT 190 EOP Balance at December 31, 2022</b>	<b>85,078</b>												
<b>Adjustment</b>	<b>(566,792)</b>	<b>Ref 8.3</b>											

PacifiCorp  
Oregon General Rate Case - December 2023  
Pro Forma Plant Additions and Retirements

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Steam Plant	312	3	(7,415,427)	SG	26.070%	(1,933,227)	
Steam Plant	312	3	(9,693,976)	SG	26.070%	(2,527,253)	
Steam Plant	312	3	83,311,329	SG	26.070%	21,719,548	
Steam Plant	312	3	-	SG	26.070%	-	
Hydro Plant	332	3	(29,867,468)	SG-P	26.070%	(7,786,551)	
Hydro Plant	332	3	(591,603)	SG-U	26.070%	(154,233)	
Hydro Plant	332	3	113,051,749	SG-P	26.070%	29,472,978	
Hydro Plant	332	3	30,389,979	SG-U	26.070%	7,922,771	
Other Plant	343	3	-	SG	26.070%	-	
Other Plant	343	3	30,157,070	SG	26.070%	7,862,051	
Other Plant	343	3	315,315	OR	Situs	315,315	
Other Plant	343	3	85,575,852	SG-W	26.070%	22,309,917	
Other Plant	343	3	3,947,715	SG	26.070%	1,029,183	
Transmission Plant	355	3	(3,027,279)	SG	26.070%	(789,222)	
Transmission Plant	355	3	(5,318,454)	SG	26.070%	(1,386,539)	
Transmission Plant	355	3	406,279,047	SG	26.070%	105,918,337	
Distribution Plant	360	3	5,894,163	OR	Situs	1,387,103	
Distribution Plant	361	3	11,172,975	OR	Situs	2,629,393	
Distribution Plant	362	3	92,706,497	OR	Situs	21,817,091	
Distribution Plant	364	3	121,157,198	OR	Situs	28,512,538	
Distribution Plant	365	3	76,239,951	OR	Situs	17,941,935	
Distribution Plant	366	3	37,825,102	OR	Situs	8,901,573	
Distribution Plant	367	3	88,238,304	OR	Situs	20,765,568	
Distribution Plant	368	3	133,563,546	OR	Situs	31,432,188	
Distribution Plant	369	3	82,592,480	OR	Situs	19,436,908	
Distribution Plant	370	3	22,608,398	OR	Situs	5,320,549	
Distribution Plant	371	3	781,680	OR	Situs	183,957	
Distribution Plant	373	3	5,598,039	OR	Situs	1,317,415	
General Plant	397	3	849,714	CA	Situs	-	
General Plant	397	3	19,428,697	OR	Situs	19,428,697	
General Plant	397	3	808,867	WA	Situs	-	
General Plant	397	3	7,938,874	WYP	Situs	-	
General Plant	397	3	39,988,273	UT	Situs	-	
General Plant	397	3	3,497,677	ID	Situs	-	
General Plant	397	3	(570,735)	WYU	Situs	-	
General Plant	397	3	(250,510)	SG	26.070%	(65,309)	
General Plant	397	3	(554,012)	SG	26.070%	(144,433)	
General Plant	397	3	9,280,356	SG	26.070%	2,419,421	
General Plant	397	3	55,872,042	SO	27.173%	15,182,156	
General Plant	397	3	-	SG	26.070%	-	
General Plant	397	3	-	SG	26.070%	-	
General Plant	397	3	(1,789,712)	CN	30.990%	(554,630)	
General Plant	397	3	(268,157)	SE	25.068%	(67,222)	
Mining Plant	399	3	-	SE	25.068%	-	
			<u>1,509,723,557</u>			<u>377,817,973</u>	

**Description of Adjustment:**

To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be used and useful by December 31, 2022. This adjustment includes the year end balance of the plant additions that will be placed into service by December 31, 2022. Capital additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. Projects over \$10 million (total company basis) are described on pages 8.4.28 through 8.4.32. Retirements of plant in service are also walked forward through the test period. This adjustment reflects the net impact of capital additions, and retirements.

The related tax impact is included in adjustments 7.4 and 7.5 except for a small tax adjustment not included in the Power Tax adjustment.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**(cont.) Pro Forma Plant Additions**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Intangible Plant	303	3	-	CA	Situs	-	
Intangible Plant	303	3	(615,486)	CN	30.990%	(190,739)	
Intangible Plant	302	3	-	SG	26.070%	-	
Intangible Plant	302	3	-	SG	26.070%	-	
Intangible Plant	303	3	(1,552)	ID	Situs	-	
Intangible Plant	303	3	(6,539)	OR	Situs	(6,539)	
Intangible Plant	303	3	(73,429)	SE	25.068%	(18,407)	
Intangible Plant	302	3	(1,132,698)	SG	26.070%	(295,298)	
Intangible Plant	302	3	(83,981)	SG-P	26.070%	(21,894)	
Intangible Plant	302	3	(268,568)	SG-U	26.070%	(70,017)	
Intangible Plant	303	3	-	SG	26.070%	-	
Intangible Plant	303	3	44,779,220	SO	27.173%	12,167,894	
Intangible Plant	303	3	(10,105)	UT	Situs	-	
Intangible Plant	303	3	-	WA	Situs	-	
Intangible Plant	303	3	(139,114)	WYP	Situs	-	
Intangible Plant	303	3	-	WYU	Situs	-	
			<u>42,447,748</u>			<u>11,565,000</u>	
Total Adjustment			<u>1,552,171,305</u>			<u>389,382,973</u>	8.4.4
<b>Adjustments to Tax:</b>							
Schedule M Addition - OR - Book Depr	SCHMAT	3	(51,560)	OR	Situs	(51,560)	
Schedule M Addition - SO - Book Depr	SCHMAT	3	(85,068)	SO	27.173%	(23,116)	
Schedule M Addition - SG - Book Depr	SCHMAT	3	162,039	UT	Situs	-	
Schedule M Addition - UT - Book Depr	SCHMAT	3	(1,936,866)	SG	26.070%	(504,948)	
			<u>(1,911,455)</u>			<u>(579,623)</u>	
Schedule M Deduction - OR - Tax Depreciation	SCHMDT	3	(85,125)	OR	Situs	(85,125)	
Schedule M Deduction - SO - Tax Depreciation	SCHMDT	3	4,955,879	SO	27.173%	1,346,665	
Schedule M Deduction - SG - Tax Depreciation	SCHMDT	3	2,074,888	UT	Situs	-	
Schedule M Deduction - UT - Tax Depreciation	SCHMDT	3	(6,839,470)	SG	26.070%	(1,783,073)	
			<u>106,172</u>			<u>(521,533)</u>	
Deferred Inc Tax Exp - OR - Book Depr	41110	3	12,677	OR	Situs	12,677	
Deferred Inc Tax Exp - SO - Book Depr	41110	3	20,915	SO	27.173%	5,683	
Deferred Inc Tax Exp - SG - Book Depr	41110	3	(39,840)	UT	Situs	-	
Deferred Inc Tax Exp - UT - Book Depr	41110	3	476,210	SG	26.070%	124,150	
			<u>469,962</u>			<u>142,510</u>	
Deferred Inc Tax Exp - OR - Tax Depr	41010	3	(20,929)	OR	Situs	(20,929)	
Deferred Inc Tax Exp - SO - Tax Depr	41010	3	1,218,482	SO	27.173%	331,099	
Deferred Inc Tax Exp - SG - Tax Depr	41010	3	510,144	UT	Situs	-	
Deferred Inc Tax Exp - UR - Tax Depr	41010	3	(1,681,593)	SG	26.070%	(438,397)	
			<u>26,104</u>			<u>(128,227)</u>	

**Description of Adjustment:**

To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be used and useful by December 31, 2022. This adjustment includes the year end balance of the plant additions that will be placed into service by December 31, 2022. Capital additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. Projects over \$10 million (total company basis) are described on pages 8.4.28 through 8.4.32. Retirements of plant in service are also walked forward through the test period. This adjustment reflects the net impact of capital additions, and retirements.

The related tax impact is included in adjustments 7.4 and 7.5 except for a small tax adjustment not included in the Power Tax adjustment.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**(cont.) Pro Forma Plant Additions - Incremental Tax Impacts**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Tax:</b>							
ADIT - OR	282	3	8,255	OR	Situs	8,255	
ADIT - SO	282	3	(1,299,881)	SO	27.173%	(353,218)	
ADIT - SG	282	3	(468,906)	UT	Situs	-	
ADIT - UT	282	3	1,205,387	SG	26.070%	314,249	
			<u>(555,145)</u>			<u>(30,714)</u>	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(190,965)	SG	26.070%	(49,785)	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(200,258.10)	SG	26.070%	(52,208)	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	5,547,174.14	SG	26.070%	1,446,167	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	2,465,368	OR	Situs	2,465,368	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	300,556	CA	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	590,868	WA	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	363,985	WYP	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	3,527,755	UT	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	409,149	ID	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	1,775,050	SO	27.173%	482,336	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(48,760)	CN	30.990%	(15,111)	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(8,142)	SE	25.068%	(2,041)	
			<u>14,531,780</u>			<u>4,274,727</u>	
DIT Exp - Increm. Book Depr.	41110	3	46,952	SG	26.070%	12,241	
DIT Exp - Increm. Book Depr.	41110	3	49,237	SG	26.070%	12,836	
DIT Exp - Increm. Book Depr.	41110	3	(1,363,862)	SG	26.070%	(355,563)	
DIT Exp - Increm. Book Depr.	41110	3	(606,150)	OR	Situs	(606,150)	
DIT Exp - Increm. Book Depr.	41110	3	(73,897)	CA	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(145,274)	WA	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(89,492)	WYP	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(867,355)	UT	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(100,596)	ID	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(436,425)	SO	27.173%	(118,590)	
DIT Exp - Increm. Book Depr.	41110	3	11,988	CN	30.990%	3,715	
DIT Exp - Increm. Book Depr.	41110	3	2,002	SE	25.068%	502	
			<u>(3,572,871)</u>			<u>(1,051,010)</u>	
ADIT - Increm. Book Depr.	282	3	(23,476)	SG	26.070%	(6,120)	
ADIT - Increm. Book Depr.	282	3	(24,618)	SG	26.070%	(6,418)	
ADIT - Increm. Book Depr.	282	3	681,931	SG	26.070%	177,782	
ADIT - Increm. Book Depr.	282	3	303,075	OR	Situs	303,075	
ADIT - Increm. Book Depr.	282	3	36,948	CA	Situs	-	
ADIT - Increm. Book Depr.	282	3	72,637	WA	Situs	-	
ADIT - Increm. Book Depr.	282	3	44,746	WYP	Situs	-	
ADIT - Increm. Book Depr.	282	3	433,677	UT	Situs	-	
ADIT - Increm. Book Depr.	282	3	50,298	ID	Situs	-	
ADIT - Increm. Book Depr.	282	3	218,212	SO	27.173%	59,295	
ADIT - Increm. Book Depr.	282	3	(5,994)	CN	30.990%	(1,858)	
ADIT - Increm. Book Depr.	282	3	(1,001)	SE	25.068%	(251)	
			<u>1,786,435</u>			<u>525,505</u>	

**Description of Adjustment:**

The tax portion of this adjustment represents the following:

- 1) Adjustments for the tax impacts of the differences between the original capital additions included in 7.4 - PowerTax Adjustment and the final capital additions included in this adjustment.
- 2) Tax impact of the difference between 2022 book depreciation for the original capital additions submitted and included in 7.4 - PowerTax adjustment and the final level of annualized book depreciation included in Adjustment 6.1/6.2.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
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<b>Description</b>	<b>Account</b>	<b>Factor</b>	<b>End of Period June 2021 EPIS Balance</b>	<b>Test Period EPIS Balance (End of Period)</b>	<b>Adjustment to Test Period</b>
<b>Steam Production Plant:</b>					
Pre-merger Pacific	312	SG	1,012,491,439	1,005,076,012	(7,415,427)
Pre-merger Utah	312	SG	1,059,174,518	1,049,480,541	(9,693,976)
Post-merger	312	SG	4,811,092,365	4,894,403,694	83,311,329
Post-merger	312	SG	1,266,851	1,266,851	-
Total Steam Plant			<u>6,884,025,173</u>	<u>6,950,227,099</u>	<u>66,201,926</u>
<b>Hydro Production Plant:</b>					
Pre-merger Pacific	332	SG-P	212,788,520	182,921,052	(29,867,468)
Pre-merger Utah	332	SG-U	39,865,127	39,273,524	(591,603)
Post-merger	332	SG-P	715,205,846	828,257,595	113,051,749
Post-merger	332	SG-U	152,896,613	183,286,592	30,389,979
Total Hydro Plant			<u>1,120,756,105</u>	<u>1,233,738,762</u>	<u>112,982,656</u>
<b>Other Production Plant:</b>					
Pre-merger Utah	343	SG	235,129	235,129	-
Post-merger	343	SG	1,925,969,509	1,956,126,579	30,157,070
Post-merger Wind	343	SG-W	3,160,796,216	3,246,372,067	85,575,852
Black Cap Solar	343	OR	74,986	390,301	315,315
Post-merger	343	SG	85,640,221	89,587,935	3,947,715
Total Other Production Plant			<u>5,172,716,061</u>	<u>5,292,712,012</u>	<u>119,995,951</u>
<b>Transmission Plant:</b>					
Pre-merger Pacific	355	SG	479,801,515	476,774,235	(3,027,279)
Pre-merger Utah	355	SG	620,673,594	615,355,140	(5,318,454)
Post-merger	355	SG	6,545,677,086	6,951,956,134	406,279,047
Total Transmission Plant			<u>7,646,152,195</u>	<u>8,044,085,510</u>	<u>397,933,314</u>
<b>Distribution Plant:</b>					
California	360-373	CA	290,384,821	342,198,781	51,813,960
Oregon	360-373	OR	2,324,681,909	2,484,328,127	159,646,218
Washington	360-373	WA	571,387,038	619,411,435	48,024,397
Eastern Wyoming	360-373	WYP	672,061,808	716,010,701	43,948,893
Utah	360-373	UT	3,342,346,441	3,671,327,019	328,980,577
Idaho	360-373	ID	397,879,329	444,343,741	46,464,412
Western Wyoming	360-373	WYU	155,050,984	154,550,860	(500,124)
Total Distribution Plant			<u>7,753,792,330</u>	<u>8,432,170,664</u>	<u>678,378,334</u>
<b>General Plant:</b>					
California	397	CA	23,110,673	23,960,387	849,714
Oregon	397	OR	224,756,896	244,185,593	19,428,697
Washington	397	WA	48,854,100	49,662,967	808,867
Eastern Wyoming	397	WYP	85,516,927	93,455,801	7,938,874
Utah	397	UT	237,752,017	277,740,291	39,988,273
Idaho	397	ID	51,387,414	54,885,092	3,497,677
Western Wyoming	397	WYU	18,200,958	17,630,222	(570,735)
Pre-merger Pacific	397	SG	1,007,315	756,805	(250,510)
Pre-merger Utah	397	SG	2,821,996	2,267,985	(554,012)
Post-merger	397	SG	302,412,630	311,692,986	9,280,356
General Office	397	SO	350,852,677	406,724,719	55,872,042
General Office	397	SG	-	-	-
General Office	397	SG	223,232	223,232	-
Customer Service	397	CN	17,295,589	15,505,877	(1,789,712)
Fuel Related	397	SE	3,318,698	3,050,541	(268,157)
Total General Plant			<u>1,367,511,122</u>	<u>1,501,742,497</u>	<u>134,231,375</u>

**PacifiCorp  
Oregon General Rate Case - December 2023  
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<b>Description</b>	<b>Account</b>	<b>Factor</b>	<b>End of Period June 2021 EPIS Balance</b>	<b>Test Period EPIS Balance (End of Period)</b>	<b>Adjustment to Test Period</b>
<b>Mining Plant:</b>					
Coal Mine	399	SE	1,822,901	1,822,901	-
Total Mining Plant			<u>1,822,901</u>	<u>1,822,901</u>	-
<b>Intangible Plant:</b>					
California	303	CA	481,167	481,167	-
Customer Service	303	CN	214,248,773	213,633,287	(615,486)
Pre-merger Utah	302	SG	477,596	477,596	-
Pre-merger Pacific	302	SG	-	-	-
Idaho	303	ID	4,371,145	4,369,593	(1,552)
Oregon	303	OR	4,616,002	4,609,463	(6,539)
Fuel Related	303	SE	9,106	(64,323)	(73,429)
Post-merger	302	SG	210,683,247	209,550,549	(1,132,698)
Hydro Relicensing	302	SG-P	177,566,825	177,482,844	(83,981)
Hydro Relicensing	302	SG-U	10,014,897	9,746,329	(268,568)
Post-merger	303	SG	-	-	-
General Office	303	SO	432,009,413	476,788,634	44,779,220
Utah	303	UT	(26,162,598)	(26,172,704)	(10,105)
Washington	303	WA	2,036,986	2,036,986	-
Eastern Wyoming	303	WYP	5,668,980	5,529,866	(139,114)
Western Wyoming	303	WYU	-	-	-
Total Intangible Plant			<u>1,036,021,539</u>	<u>1,078,469,287</u>	<u>42,447,748</u>
<b>Total EPIS Balance</b>			<u>30,982,797,426</u>	<u>32,534,968,731</u>	<u>1,552,171,305</u>
				<b>Ref. 8.4.18</b>	<b>Ref 8.4.1</b>

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Description	Factor	Adjusted			Adjusted			Adjusted		
		EPIS Balance Jun 2021	Capital Additions	Retirements	EPIS Balance Jul 2021	Capital Additions	Retirements	EPIS Balance Aug 2021	Capital Additions	Retirements
<b>Steam Production Plant:</b>										
Pre-merger Pacific	SG	1,012,491,439	-	(411,968)	1,012,079,471	-	(411,968)	1,011,667,503	-	(411,968)
Pre-merger Utah	SG	1,059,174,518	-	(538,554)	1,058,635,963	-	(538,554)	1,058,097,409	-	(538,554)
Post-merger	SG	4,781,690,336	1,666,618	(3,118,406)	4,780,238,549	2,372,696	(3,118,406)	4,779,492,840	420,169	(3,118,406)
Geothermal - Blundell	SG	29,402,029	-	-	29,402,029	-	-	29,402,029	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		6,884,025,173	1,666,618	(4,068,928)	6,881,622,863	2,372,696	(4,068,928)	6,879,926,632	420,169	(4,068,928)
<b>Hydro Production Plant:</b>										
Pre-merger Pacific	SG	183,823,226	-	(50,121)	183,773,105	-	(50,121)	183,722,984	-	(50,121)
Pre-merger Utah	SG	39,865,127	-	(32,867)	39,832,260	-	(32,867)	39,799,393	-	(32,867)
Post-merger	SG-P	649,962,674	(321,167)	(183,427)	649,458,080	32,086	(183,427)	649,306,738	1,273,181	(183,427)
Post-merger	SG-U	152,896,613	206,846	(37,209)	153,066,250	(69,239)	(37,209)	152,959,802	533,219	(37,209)
Klamath - New Capital	SG-P	2,703,876	-	-	2,703,876	-	-	2,703,876	281,024	-
Klamath	SG-P	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant		1,120,756,105	(114,320)	(303,624)	1,120,338,161	(37,153)	(303,624)	1,119,997,384	2,087,424	(303,624)
<b>Other Production Plant:</b>										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,925,969,509	(85,685)	(2,040,058)	1,923,843,767	105,347	(2,040,058)	1,921,909,056	(98,126)	(2,040,058)
Post-merger Wind	SG-W	3,160,796,216	30,277,179	(238,555)	3,190,834,840	6,686,559	(238,555)	3,197,282,844	11,781,414	(238,555)
Black Cap Solar	OR	74,986	-	-	74,986	-	-	74,986	-	-
Post-merger	SG	85,640,221	1,317,138	(46,204)	86,911,154	6,803	(46,204)	86,871,753	3,301,375	(46,204)
Total Other Plant		5,172,716,061	31,508,632	(2,324,817)	5,201,899,876	6,798,710	(2,324,817)	5,206,373,769	14,984,662	(2,324,817)
<b>Transmission Plant:</b>										
Pre-merger Pacific	SG	479,801,515	-	(168,182)	479,633,333	-	(168,182)	479,465,150	-	(168,182)
Pre-merger Utah	SG	620,673,594	-	(295,470)	620,378,125	-	(295,470)	620,082,655	-	(295,470)
Post-merger	SG	6,545,677,086	11,060,066	(726,705)	6,556,010,447	53,616	(726,705)	6,555,337,357	18,356,928	(726,705)
Total Transmission Plant		7,646,152,195	11,060,066	(1,190,357)	7,656,021,904	53,616	(1,190,357)	7,654,885,162	18,356,928	(1,190,357)
<b>Distribution Plant:</b>										
California	CA	290,384,821	645,415	(145,707)	290,884,529	536,179	(145,707)	291,275,000	1,600,597	(145,707)
Oregon	OR	2,324,681,909	5,282,606	(1,763,593)	2,328,200,922	5,414,252	(1,763,593)	2,331,851,581	16,924,526	(1,763,593)
Washington	WA	571,387,038	2,054,355	(198,825)	573,242,568	1,452,522	(198,825)	574,496,264	1,609,293	(198,825)
Eastern Wyoming	WYP	672,061,808	2,347,876	(271,721)	674,137,963	1,553,562	(271,721)	675,419,805	2,621,401	(271,721)
Utah	UT	3,342,346,441	15,086,395	(1,414,241)	3,356,018,595	8,549,801	(1,414,241)	3,363,154,155	24,191,247	(1,414,241)
Idaho	ID	397,879,329	991,413	(155,146)	398,715,596	1,147,132	(155,146)	399,707,583	2,431,771	(155,146)
Western Wyoming	WYU	155,050,984	-	(27,785)	155,023,199	-	(27,785)	154,995,414	-	(27,785)
Total Distribution Plant		7,753,792,330	26,408,059	(3,977,018)	7,776,223,372	18,653,447	(3,977,018)	7,790,899,802	49,378,834	(3,977,018)

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Description	Factor	Adjusted			Adjusted			Adjusted		
		EPIS Balance Jun 2021	Capital Additions	Retirements	EPIS Balance Jul 2021	Capital Additions	Retirements	EPIS Balance Aug 2021	Capital Additions	Retirements
<b>General Plant:</b>										
California	CA	23,110,673	7,486	(43,689)	23,074,470	19,869	(43,689)	23,050,650	18,876	(43,689)
Oregon	OR	224,756,896	139,341	(323,194)	224,573,042	165,583	(323,194)	224,415,430	930,890	(323,194)
Washington	WA	48,854,100	18,419	(115,214)	48,757,305	(3,465)	(115,214)	48,638,626	309,906	(115,214)
Eastern Wyoming	WYP	85,516,927	25,070	(254,299)	85,287,698	211,362	(254,299)	85,244,761	603,199	(254,299)
Utah	UT	237,752,017	544,265	(479,305)	237,816,977	2,470,547	(479,305)	239,808,219	1,202,961	(479,305)
Idaho	ID	51,387,414	21,199	(68,917)	51,339,697	44,593	(68,917)	51,315,374	165,905	(68,917)
Western Wyoming	WYU	18,200,958	-	(31,708)	18,169,250	-	(31,708)	18,137,543	-	(31,708)
Pre-merger Pacific	SG	1,007,315	-	(13,917)	993,398	-	(13,917)	979,480	-	(13,917)
Pre-merger Utah	SG	2,821,996	-	(30,778)	2,791,218	-	(30,778)	2,760,439	-	(30,778)
Post-merger	SG	302,412,630	277,423	(578,398)	302,111,654	295,555	(578,398)	301,828,810	116,386	(578,398)
General Office	SO	350,852,677	742,036	(1,303,426)	350,291,286	1,504,749	(1,303,426)	350,492,609	6,213,747	(1,303,426)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	223,232	-	-	223,232	-	-	223,232	-	-
Customer Service	CN	17,295,589	-	(99,428)	17,196,160	-	(99,428)	17,096,732	-	(99,428)
Fuel Related	SE	3,318,698	-	(14,898)	3,303,800	-	(14,898)	3,288,902	-	(14,898)
Total General Plant		1,367,511,122	1,775,238	(3,357,172)	1,365,929,188	4,708,792	(3,357,172)	1,367,280,809	9,561,870	(3,357,172)
<b>Mining Plant:</b>										
Coal Mine	SE	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant		1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
<b>Intangible Plant:</b>										
California	CA	481,167	-	-	481,167	-	-	481,167	-	-
Customer Service	CN	214,248,773	-	(34,194)	214,214,579	-	(34,194)	214,180,385	-	(34,194)
Pre-merger Utah	SG	477,596	-	-	477,596	-	-	477,596	-	-
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,371,145	-	(86)	4,371,059	-	(86)	4,370,973	-	(86)
Oregon	OR	4,616,002	-	(363)	4,615,639	-	(363)	4,615,275	-	(363)
Fuel Related	SE	9,106	-	(4,079)	5,026	-	(4,079)	947	-	(4,079)
Post-merger	SG	210,683,247	-	(62,928)	210,620,319	-	(62,928)	210,557,391	-	(62,928)
Klamath Hydro Relicensing	SG-P	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-
Hydro Relicensing	SG-P	103,455,075	-	(4,666)	103,450,409	-	(4,666)	103,445,744	-	(4,666)
Hydro Relicensing	SG-U	10,014,897	-	(14,920)	9,999,977	-	(14,920)	9,985,056	-	(14,920)
General Office	SO	432,009,413	2,550,130	(1,123,079)	433,436,464	(849,846)	(1,123,079)	431,463,539	3,144,709	(1,123,079)
Utah	UT	(26,162,598)	-	(561)	(26,163,160)	-	(561)	(26,163,721)	-	(561)
Washington	WA	2,036,986	-	-	2,036,986	-	-	2,036,986	-	-
Eastern Wyoming	WYP	5,668,980	-	(7,729)	5,661,251	-	(7,729)	5,653,523	-	(7,729)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,036,021,539	2,550,130	(1,252,606)	1,037,319,063	(849,846)	(1,252,606)	1,035,216,612	3,144,709	(1,252,606)
<b>Total</b>		<b>30,982,797,426</b>	<b>74,854,424</b>	<b>(16,474,521)</b>	<b>31,041,177,329</b>	<b>31,700,262</b>	<b>(16,474,521)</b>	<b>31,056,403,070</b>	<b>97,934,596</b>	<b>(16,474,521)</b>



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Description	Factor	Adjusted			Adjusted			Adjusted		
		EPIS Balance Sep 2021	Capital Additions	Retirements	EPIS Balance Oct 2021	Capital Additions	Retirements	EPIS Balance Nov 2021	Capital Additions	Retirements
<b>Steam Production Plant:</b>										
Pre-merger Pacific	SG	1,011,255,535	-	(411,968)	1,010,843,566	-	(411,968)	1,010,431,598	-	(411,968)
Pre-merger Utah	SG	1,057,558,855	-	(538,554)	1,057,020,301	-	(538,554)	1,056,481,746	-	(538,554)
Post-merger	SG	4,776,794,603	13,902,238	(3,118,406)	4,787,578,436	2,776,222	(3,118,406)	4,787,236,252	11,239,740	(3,118,406)
Geothermal - Blundell	SG	29,402,029	-	-	29,402,029	-	-	29,402,029	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		6,876,277,873	13,902,238	(4,068,928)	6,886,111,183	2,776,222	(4,068,928)	6,884,818,477	11,239,740	(4,068,928)
<b>Hydro Production Plant:</b>										
Pre-merger Pacific	SG	183,672,864	-	(50,121)	183,622,743	-	(50,121)	183,572,622	-	(50,121)
Pre-merger Utah	SG	39,766,526	-	(32,867)	39,733,659	-	(32,867)	39,700,792	-	(32,867)
Post-merger	SG-P	650,396,491	1,960,975	(183,427)	652,174,038	3,841,421	(183,427)	655,832,032	13,545,140	(183,427)
Post-merger	SG-U	153,455,812	265,198	(37,209)	153,683,801	1,389,574	(37,209)	155,036,166	6,998,790	(37,209)
Klamath - New Capital	SG-P	2,984,900	73,294	-	3,058,193	1,112,940	-	4,171,133	-	-
Klamath	SG-P	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant		1,121,781,183	2,299,466	(303,624)	1,123,777,025	6,343,935	(303,624)	1,129,817,336	20,543,931	(303,624)
<b>Other Production Plant:</b>										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,919,770,872	28,585,744	(2,040,058)	1,946,316,558	307,145	(2,040,058)	1,944,583,646	468,979	(2,040,058)
Post-merger Wind	SG-W	3,208,825,703	19,075,668	(238,555)	3,227,662,816	3,450,399	(238,555)	3,230,874,661	3,651,610	(238,555)
Black Cap Solar	OR	74,986	-	-	74,986	-	-	74,986	255,090	-
Post-merger	SG	90,126,924	6,803	(46,204)	90,087,523	6,803	(46,204)	90,048,121	6,803	(46,204)
Total Other Plant		5,219,033,614	47,668,215	(2,324,817)	5,264,377,012	3,764,348	(2,324,817)	5,265,816,543	4,382,483	(2,324,817)
<b>Transmission Plant:</b>										
Pre-merger Pacific	SG	479,296,968	-	(168,182)	479,128,786	-	(168,182)	478,960,604	-	(168,182)
Pre-merger Utah	SG	619,787,185	-	(295,470)	619,491,716	-	(295,470)	619,196,246	-	(295,470)
Post-merger	SG	6,572,967,580	40,334,673	(726,705)	6,612,575,548	41,469,010	(726,705)	6,653,317,852	38,893,112	(726,705)
Total Transmission Plant		7,672,051,734	40,334,673	(1,190,357)	7,711,196,050	41,469,010	(1,190,357)	7,751,474,702	38,893,112	(1,190,357)
<b>Distribution Plant:</b>										
California	CA	292,729,890	1,193,784	(145,707)	293,777,967	11,459,835	(145,707)	305,092,094	1,201,797	(145,707)
Oregon	OR	2,347,012,514	5,790,056	(1,763,593)	2,351,038,977	4,686,243	(1,763,593)	2,353,961,626	10,416,317	(1,763,593)
Washington	WA	575,906,732	1,134,154	(198,825)	576,842,061	946,235	(198,825)	577,589,471	1,384,719	(198,825)
Eastern Wyoming	WYP	677,769,484	2,290,590	(271,721)	679,788,354	2,206,195	(271,721)	681,722,828	13,525,926	(271,721)
Utah	UT	3,385,931,161	22,655,780	(1,414,241)	3,407,172,700	11,999,512	(1,414,241)	3,417,757,971	23,813,278	(1,414,241)
Idaho	ID	401,984,208	3,665,053	(155,146)	405,494,115	7,485,792	(155,146)	412,824,762	2,823,622	(155,146)
Western Wyoming	WYU	154,967,630	-	(27,785)	154,939,845	-	(27,785)	154,912,060	-	(27,785)
Total Distribution Plant		7,836,301,618	36,729,418	(3,977,018)	7,869,054,018	38,783,812	(3,977,018)	7,903,860,813	53,165,659	(3,977,018)

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Description	Factor	Adjusted			Adjusted			Adjusted		
		EPIS Balance Sep 2021	Capital Additions	Retirements	EPIS Balance Oct 2021	Capital Additions	Retirements	EPIS Balance Nov 2021	Capital Additions	Retirements
<b>General Plant:</b>										
California	CA	23,025,838	70,798	(43,689)	23,052,947	11,560	(43,689)	23,020,818	6,804	(43,689)
Oregon	OR	225,023,126	1,473,789	(323,194)	226,173,721	1,134,904	(323,194)	226,985,431	7,498,427	(323,194)
Washington	WA	48,833,318	191,512	(115,214)	48,909,616	146,783	(115,214)	48,941,185	185,591	(115,214)
Eastern Wyoming	WYP	85,593,662	734,332	(254,299)	86,073,695	498,337	(254,299)	86,317,734	3,020,677	(254,299)
Utah	UT	240,531,874	3,197,351	(479,305)	243,249,919	2,906,931	(479,305)	245,677,545	7,500,933	(479,305)
Idaho	ID	51,412,362	369,636	(68,917)	51,713,081	277,497	(68,917)	51,921,662	1,204,478	(68,917)
Western Wyoming	WYU	18,105,835	-	(31,708)	18,074,128	-	(31,708)	18,042,420	-	(31,708)
Pre-merger Pacific	SG	965,563	-	(13,917)	951,646	-	(13,917)	937,729	-	(13,917)
Pre-merger Utah	SG	2,729,661	-	(30,778)	2,698,882	-	(30,778)	2,668,104	-	(30,778)
Post-merger	SG	301,366,798	604,717	(578,398)	301,393,117	957,134	(578,398)	301,771,852	5,529,597	(578,398)
General Office	SO	355,402,930	24,734,212	(1,303,426)	378,833,715	7,178,989	(1,303,426)	384,709,278	8,353,715	(1,303,426)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	223,232	-	-	223,232	-	-	223,232	-	-
Customer Service	CN	16,997,303	-	(99,428)	16,897,875	-	(99,428)	16,798,447	-	(99,428)
Fuel Related	SE	3,274,005	-	(14,898)	3,259,107	-	(14,898)	3,244,210	-	(14,898)
Total General Plant		1,373,485,507	31,376,347	(3,357,172)	1,401,504,682	13,112,136	(3,357,172)	1,411,259,647	33,300,223	(3,357,172)
<b>Mining Plant:</b>										
Coal Mine	SE	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant		1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
<b>Intangible Plant:</b>										
California	CA	481,167	-	-	481,167	-	-	481,167	-	-
Customer Service	CN	214,146,192	-	(34,194)	214,111,998	-	(34,194)	214,077,804	-	(34,194)
Pre-merger Utah	SG	477,596	-	-	477,596	-	-	477,596	-	-
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,370,886	-	(86)	4,370,800	-	(86)	4,370,714	-	(86)
Oregon	OR	4,614,912	-	(363)	4,614,549	-	(363)	4,614,186	-	(363)
Fuel Related	SE	(3,132)	-	(4,079)	(7,212)	-	(4,079)	(11,291)	-	(4,079)
Post-merger	SG	210,494,464	-	(62,928)	210,431,536	-	(62,928)	210,368,609	-	(62,928)
Klamath Hydro Relicensing	SG-P	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-
Hydro Relicensing	SG-P	103,441,078	-	(4,666)	103,436,412	-	(4,666)	103,431,747	-	(4,666)
Hydro Relicensing	SG-U	9,970,136	-	(14,920)	9,955,215	-	(14,920)	9,940,295	-	(14,920)
General Office	SO	433,485,169	1,412,688	(1,123,079)	433,774,777	8,808,993	(1,123,079)	441,460,691	6,240,861	(1,123,079)
Utah	UT	(26,164,283)	-	(561)	(26,164,844)	-	(561)	(26,165,405)	-	(561)
Washington	WA	2,036,986	-	-	2,036,986	-	-	2,036,986	-	-
Eastern Wyoming	WYP	5,645,794	-	(7,729)	5,638,066	-	(7,729)	5,630,337	-	(7,729)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,037,108,715	1,412,688	(1,252,606)	1,037,268,798	8,808,993	(1,252,606)	1,044,825,185	6,240,861	(1,252,606)
<b>Total</b>		<b>31,137,863,145</b>	<b>173,723,045</b>	<b>(16,474,521)</b>	<b>31,295,111,669</b>	<b>115,058,455</b>	<b>(16,474,521)</b>	<b>31,393,695,603</b>	<b>167,766,008</b>	<b>(16,474,521)</b>

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Description	Factor	Adjusted			Adjusted			Adjusted		
		EPIS Balance Dec 2021	Capital Additions	Retirements	EPIS Balance Jan 2022	Capital Additions	Retirements	EPIS Balance Feb 2022	Capital Additions	Retirements
<b>Steam Production Plant:</b>										
Pre-merger Pacific	SG	1,010,019,630	-	(411,968)	1,009,607,662	-	(411,968)	1,009,195,694	-	(411,968)
Pre-merger Utah	SG	1,055,943,192	-	(538,554)	1,055,404,638	-	(538,554)	1,054,866,084	-	(538,554)
Post-merger	SG	4,795,357,586	(559,421)	(3,118,406)	4,791,679,759	(283,879)	(3,118,406)	4,788,277,475	100,642	(3,118,406)
Geothermal - Blundell	SG	29,402,029	-	-	29,402,029	-	-	29,402,029	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		6,891,989,289	(559,421)	(4,068,928)	6,887,360,939	(283,879)	(4,068,928)	6,883,008,133	100,642	(4,068,928)
<b>Hydro Production Plant:</b>										
Pre-merger Pacific	SG	183,522,501	-	(50,121)	183,472,380	-	(50,121)	183,422,260	-	(50,121)
Pre-merger Utah	SG	39,667,926	-	(32,867)	39,635,059	-	(32,867)	39,602,192	-	(32,867)
Post-merger	SG-P	669,193,744	48,940	(183,427)	669,059,256	2,852,738	(183,427)	671,728,567	1,379,843	(183,427)
Post-merger	SG-U	161,997,747	(64,385)	(37,209)	161,896,153	(64,385)	(37,209)	161,794,558	(64,385)	(37,209)
Klamath - New Capital	SG-P	4,171,133	-	-	4,171,133	-	-	4,171,133	-	-
Klamath	SG-P	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant		1,150,057,642	(15,446)	(303,624)	1,149,738,572	2,788,353	(303,624)	1,152,223,301	1,315,458	(303,624)
<b>Other Production Plant:</b>										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,943,012,568	(22,862)	(2,040,058)	1,940,949,647	(22,862)	(2,040,058)	1,938,886,727	(22,862)	(2,040,058)
Post-merger Wind	SG-W	3,234,287,716	1,241,001	(238,555)	3,235,290,162	1,241,001	(238,555)	3,236,292,608	1,241,001	(238,555)
Black Cap Solar	OR	330,076	5,019	-	335,095	5,019	-	340,114	5,019	-
Post-merger	SG	90,008,720	4,057	(46,204)	89,966,573	4,057	(46,204)	89,924,426	4,057	(46,204)
Total Other Plant		5,267,874,210	1,227,215	(2,324,817)	5,266,776,607	1,227,215	(2,324,817)	5,265,679,005	1,227,215	(2,324,817)
<b>Transmission Plant:</b>										
Pre-merger Pacific	SG	478,792,422	-	(168,182)	478,624,239	-	(168,182)	478,456,057	-	(168,182)
Pre-merger Utah	SG	618,900,776	-	(295,470)	618,605,307	-	(295,470)	618,309,837	-	(295,470)
Post-merger	SG	6,691,484,258	3,647,374	(726,705)	6,694,404,927	4,955,659	(726,705)	6,698,633,881	8,841,942	(726,705)
Total Transmission Plant		7,789,177,457	3,647,374	(1,190,357)	7,791,634,473	4,955,659	(1,190,357)	7,795,399,775	8,841,942	(1,190,357)
<b>Distribution Plant:</b>										
California	CA	306,148,183	1,027,416	(145,707)	307,029,892	1,338,540	(145,707)	308,222,724	3,933,252	(145,707)
Oregon	OR	2,362,614,351	3,352,293	(1,763,593)	2,364,203,051	3,698,605	(1,763,593)	2,366,138,063	15,338,378	(1,763,593)
Washington	WA	578,775,365	961,278	(198,825)	579,537,818	1,024,937	(198,825)	580,363,930	2,379,135	(198,825)
Eastern Wyoming	WYP	694,977,033	1,545,034	(271,721)	696,250,347	1,524,579	(271,721)	697,503,205	1,766,289	(271,721)
Utah	UT	3,440,157,008	12,465,084	(1,414,241)	3,451,207,851	15,826,645	(1,414,241)	3,465,620,255	24,013,749	(1,414,241)
Idaho	ID	415,493,238	2,591,755	(155,146)	417,929,847	1,944,442	(155,146)	419,719,143	2,855,436	(155,146)
Western Wyoming	WYU	154,884,276	-	(27,785)	154,856,491	-	(27,785)	154,828,706	-	(27,785)
Total Distribution Plant		7,953,049,454	21,942,860	(3,977,018)	7,971,015,296	25,357,748	(3,977,018)	7,992,396,027	50,286,239	(3,977,018)

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		EPIS Balance Dec 2021	Capital Additions	Retirements	EPIS Balance Jan 2022	Capital Additions	Retirements	EPIS Balance Feb 2022	Capital Additions	Retirements
<b>General Plant:</b>										
California	CA	22,983,934	71,628	(43,689)	23,011,873	26,648	(43,689)	22,994,833	73,832	(43,689)
Oregon	OR	234,160,664	552,726	(323,194)	234,390,196	215,415	(323,194)	234,282,417	578,574	(323,194)
Washington	WA	49,011,562	108,868	(115,214)	49,005,216	41,235	(115,214)	48,931,237	112,263	(115,214)
Eastern Wyoming	WYP	89,084,112	548,873	(254,299)	89,378,687	229,406	(254,299)	89,353,794	271,212	(254,299)
Utah	UT	252,699,172	2,539,502	(479,305)	254,759,368	1,701,640	(479,305)	255,981,703	1,997,019	(479,305)
Idaho	ID	53,057,223	218,201	(68,917)	53,206,508	111,884	(68,917)	53,249,475	126,350	(68,917)
Western Wyoming	WYU	18,010,713	-	(31,708)	17,979,005	-	(31,708)	17,947,298	-	(31,708)
Pre-merger Pacific	SG	923,811	-	(13,917)	909,894	-	(13,917)	895,977	-	(13,917)
Pre-merger Utah	SG	2,637,326	-	(30,778)	2,606,547	-	(30,778)	2,575,769	-	(30,778)
Post-merger	SG	306,723,051	226,672	(578,398)	306,371,325	262,530	(578,398)	306,055,456	305,596	(578,398)
General Office	SO	391,759,567	1,250,598	(1,303,426)	391,706,738	1,230,754	(1,303,426)	391,634,066	727,858	(1,303,426)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	223,232	-	-	223,232	-	-	223,232	-	-
Customer Service	CN	16,699,018	-	(99,428)	16,599,590	-	(99,428)	16,500,161	-	(99,428)
Fuel Related	SE	3,229,312	-	(14,898)	3,214,414	-	(14,898)	3,199,517	-	(14,898)
Total General Plant		1,441,202,698	5,517,069	(3,357,172)	1,443,362,595	3,819,511	(3,357,172)	1,443,824,935	4,192,703	(3,357,172)
<b>Mining Plant:</b>										
Coal Mine	SE	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant		1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
<b>Intangible Plant:</b>										
California	CA	481,167	-	-	481,167	-	-	481,167	-	-
Customer Service	CN	214,043,611	-	(34,194)	214,009,417	-	(34,194)	213,975,223	-	(34,194)
Pre-merger Utah	SG	477,596	-	-	477,596	-	-	477,596	-	-
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,370,628	-	(86)	4,370,541	-	(86)	4,370,455	-	(86)
Oregon	OR	4,613,822	-	(363)	4,613,459	-	(363)	4,613,096	-	(363)
Fuel Related	SE	(15,371)	-	(4,079)	(19,450)	-	(4,079)	(23,529)	-	(4,079)
Post-merger	SG	210,305,681	-	(62,928)	210,242,753	-	(62,928)	210,179,826	-	(62,928)
Klamath Hydro Relicensing	SG-P	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-
Hydro Relicensing	SG-P	103,427,081	-	(4,666)	103,422,416	-	(4,666)	103,417,750	-	(4,666)
Hydro Relicensing	SG-U	9,925,374	-	(14,920)	9,910,454	-	(14,920)	9,895,534	-	(14,920)
General Office	SO	446,578,473	4,201,860	(1,123,079)	449,657,253	526,670	(1,123,079)	449,060,844	1,346,770	(1,123,079)
Utah	UT	(26,165,967)	-	(561)	(26,166,528)	-	(561)	(26,167,090)	-	(561)
Washington	WA	2,036,986	-	-	2,036,986	-	-	2,036,986	-	-
Eastern Wyoming	WYP	5,622,608	-	(7,729)	5,614,880	-	(7,729)	5,607,151	-	(7,729)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,049,813,441	4,201,860	(1,252,606)	1,052,762,695	526,670	(1,252,606)	1,052,036,760	1,346,770	(1,252,606)
<b>Total</b>		<b>31,544,987,089</b>	<b>35,961,511</b>	<b>(16,474,521)</b>	<b>31,564,474,079</b>	<b>38,391,278</b>	<b>(16,474,521)</b>	<b>31,586,390,835</b>	<b>67,310,969</b>	<b>(16,474,521)</b>

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Description	Factor	Adjusted			Adjusted			Adjusted		
		EPIS Balance Mar 2022	Capital Additions	Retirements	EPIS Balance Apr 2022	Capital Additions	Retirements	EPIS Balance May 2022	Capital Additions	Retirements
<b>Steam Production Plant:</b>										
Pre-merger Pacific	SG	1,008,783,726	-	(411,968)	1,008,371,757	-	(411,968)	1,007,959,789	-	(411,968)
Pre-merger Utah	SG	1,054,327,529	-	(538,554)	1,053,788,975	-	(538,554)	1,053,250,421	-	(538,554)
Post-merger	SG	4,785,259,712	23,571,636	(3,118,406)	4,805,712,942	36,258,316	(3,118,406)	4,838,852,852	14,382,932	(3,118,406)
Geothermal - Blundell	SG	29,402,029	-	-	29,402,029	-	-	29,402,029	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		6,879,039,847	23,571,636	(4,068,928)	6,898,542,555	36,258,316	(4,068,928)	6,930,731,943	14,382,932	(4,068,928)
<b>Hydro Production Plant:</b>										
Pre-merger Pacific	SG	183,372,139	-	(50,121)	183,322,018	-	(50,121)	183,271,897	-	(50,121)
Pre-merger Utah	SG	39,569,325	-	(32,867)	39,536,458	-	(32,867)	39,503,591	-	(32,867)
Post-merger	SG-P	672,924,983	368,832	(183,427)	673,110,388	782,015	(183,427)	673,708,975	11,896,857	(183,427)
Post-merger	SG-U	161,692,964	(64,385)	(37,209)	161,591,370	(64,385)	(37,209)	161,489,775	4,980	(37,209)
Klamath - New Capital	SG-P	4,171,133	-	-	4,171,133	-	-	4,171,133	-	-
Klamath	SG-P	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant		1,153,235,135	304,447	(303,624)	1,153,235,958	717,630	(303,624)	1,153,649,963	11,901,837	(303,624)
<b>Other Production Plant:</b>										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,936,823,807	23,394,000	(2,040,058)	1,958,177,749	3,538,513	(2,040,058)	1,959,676,204	914,001	(2,040,058)
Post-merger Wind	SG-W	3,237,295,054	1,241,001	(238,555)	3,238,297,500	1,296,001	(238,555)	3,239,354,946	1,241,001	(238,555)
Black Cap Solar	OR	345,132	5,019	-	350,151	5,019	-	355,170	5,019	-
Post-merger	SG	89,882,279	4,057	(46,204)	89,840,132	4,057	(46,204)	89,797,985	26,451	(46,204)
Total Other Plant		5,264,581,402	24,644,077	(2,324,817)	5,286,900,662	4,843,590	(2,324,817)	5,289,419,434	2,186,471	(2,324,817)
<b>Transmission Plant:</b>										
Pre-merger Pacific	SG	478,287,875	-	(168,182)	478,119,693	-	(168,182)	477,951,511	-	(168,182)
Pre-merger Utah	SG	618,014,367	-	(295,470)	617,718,898	-	(295,470)	617,423,428	-	(295,470)
Post-merger	SG	6,706,749,117	11,649,338	(726,705)	6,717,671,749	29,104,520	(726,705)	6,746,049,564	19,358,660	(726,705)
Total Transmission Plant		7,803,051,360	11,649,338	(1,190,357)	7,813,510,340	29,104,520	(1,190,357)	7,841,424,503	19,358,660	(1,190,357)
<b>Distribution Plant:</b>										
California	CA	312,010,268	1,178,065	(145,707)	313,042,626	5,710,843	(145,707)	318,607,761	6,894,949	(145,707)
Oregon	OR	2,379,712,848	7,204,251	(1,763,593)	2,385,153,507	29,158,579	(1,763,593)	2,412,548,493	20,595,283	(1,763,593)
Washington	WA	582,544,240	2,042,714	(198,825)	584,388,128	3,093,232	(198,825)	587,282,535	2,944,352	(198,825)
Eastern Wyoming	WYP	698,997,773	1,908,736	(271,721)	700,634,788	2,609,027	(271,721)	702,972,094	2,196,900	(271,721)
Utah	UT	3,488,219,763	17,113,779	(1,414,241)	3,503,919,302	35,695,541	(1,414,241)	3,538,200,602	21,006,603	(1,414,241)
Idaho	ID	422,419,434	2,232,285	(155,146)	424,496,574	3,208,573	(155,146)	427,550,001	2,154,386	(155,146)
Western Wyoming	WYU	154,800,922	-	(27,785)	154,773,137	-	(27,785)	154,745,352	-	(27,785)
Total Distribution Plant		8,038,705,249	31,679,830	(3,977,018)	8,066,408,061	79,475,795	(3,977,018)	8,141,906,838	55,792,474	(3,977,018)

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Description	Factor	Adjusted			Adjusted			Adjusted		
		EPIS Balance Mar 2022	Capital Additions	Retirements	EPIS Balance Apr 2022	Capital Additions	Retirements	EPIS Balance May 2022	Capital Additions	Retirements
<b>General Plant:</b>										
California	CA	23,024,976	17,091	(43,689)	22,998,378	36,774	(43,689)	22,991,464	80,819	(43,689)
Oregon	OR	234,537,796	784,741	(323,194)	234,999,343	976,084	(323,194)	235,652,233	1,467,605	(323,194)
Washington	WA	48,928,286	96,426	(115,214)	48,909,498	129,074	(115,214)	48,923,357	215,570	(115,214)
Eastern Wyoming	WYP	89,370,708	444,456	(254,299)	89,560,865	564,258	(254,299)	89,870,825	725,731	(254,299)
Utah	UT	257,499,416	2,242,747	(479,305)	259,262,858	3,053,717	(479,305)	261,837,269	3,452,282	(479,305)
Idaho	ID	53,306,909	125,449	(68,917)	53,363,441	165,495	(68,917)	53,460,019	219,875	(68,917)
Western Wyoming	WYU	17,915,590	-	(31,708)	17,883,883	-	(31,708)	17,852,175	-	(31,708)
Pre-merger Pacific	SG	882,060	-	(13,917)	868,143	-	(13,917)	854,225	-	(13,917)
Pre-merger Utah	SG	2,544,990	-	(30,778)	2,514,212	-	(30,778)	2,483,433	-	(30,778)
Post-merger	SG	305,782,654	349,542	(578,398)	305,553,798	305,628	(578,398)	305,281,027	305,942	(578,398)
General Office	SO	391,058,497	1,396,945	(1,303,426)	391,152,016	2,435,058	(1,303,426)	392,283,647	4,339,213	(1,303,426)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	223,232	-	-	223,232	-	-	223,232	-	-
Customer Service	CN	16,400,733	-	(99,428)	16,301,304	-	(99,428)	16,201,876	-	(99,428)
Fuel Related	SE	3,184,619	-	(14,898)	3,169,722	-	(14,898)	3,154,824	-	(14,898)
Total General Plant		1,444,660,466	5,457,397	(3,357,172)	1,446,760,692	7,666,087	(3,357,172)	1,451,069,607	10,807,036	(3,357,172)
<b>Mining Plant:</b>										
Coal Mine	SE	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant		1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
<b>Intangible Plant:</b>										
California	CA	481,167	-	-	481,167	-	-	481,167	-	-
Customer Service	CN	213,941,030	-	(34,194)	213,906,836	-	(34,194)	213,872,642	-	(34,194)
Pre-merger Utah	SG	477,596	-	-	477,596	-	-	477,596	-	-
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,370,369	-	(86)	4,370,283	-	(86)	4,370,196	-	(86)
Oregon	OR	4,612,732	-	(363)	4,612,369	-	(363)	4,612,006	-	(363)
Fuel Related	SE	(27,609)	-	(4,079)	(31,688)	-	(4,079)	(35,767)	-	(4,079)
Post-merger	SG	210,116,898	-	(62,928)	210,053,970	-	(62,928)	209,991,043	-	(62,928)
Klamath Hydro Relicensing	SG-P	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-
Hydro Relicensing	SG-P	103,413,085	-	(4,666)	103,408,419	-	(4,666)	103,403,753	-	(4,666)
Hydro Relicensing	SG-U	9,880,613	-	(14,920)	9,865,693	-	(14,920)	9,850,772	-	(14,920)
General Office	SO	449,284,535	1,558,576	(1,123,079)	449,720,031	1,084,730	(1,123,079)	449,681,682	13,728,833	(1,123,079)
Utah	UT	(26,167,651)	-	(561)	(26,168,212)	-	(561)	(26,168,774)	-	(561)
Washington	WA	2,036,986	-	-	2,036,986	-	-	2,036,986	-	-
Eastern Wyoming	WYP	5,599,423	-	(7,729)	5,591,694	-	(7,729)	5,583,966	-	(7,729)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,052,130,924	1,558,576	(1,252,606)	1,052,436,894	1,084,730	(1,252,606)	1,052,269,019	13,728,833	(1,252,606)
<b>Total</b>		<b>31,637,227,283</b>	<b>98,865,300</b>	<b>(16,474,521)</b>	<b>31,719,618,062</b>	<b>159,150,667</b>	<b>(16,474,521)</b>	<b>31,862,294,208</b>	<b>128,158,242</b>	<b>(16,474,521)</b>

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Description	Factor	Adjusted			Adjusted			Adjusted		
		EPIS Balance Jun 2022	Capital Additions	Retirements	EPIS Balance Jul 2022	Capital Additions	Retirements	EPIS Balance Aug 2022	Capital Additions	Retirements
<b>Steam Production Plant:</b>										
Pre-merger Pacific	SG	1,007,547,821	-	(411,968)	1,007,135,853	-	(411,968)	1,006,723,885	-	(411,968)
Pre-merger Utah	SG	1,052,711,867	-	(538,554)	1,052,173,312	-	(538,554)	1,051,634,758	-	(538,554)
Post-merger	SG	4,850,117,378	5,909,808	(3,118,406)	4,852,908,780	(303,139)	(3,118,406)	4,849,487,236	123,052	(3,118,406)
Geothermal - Blundell	SG	29,402,029	-	-	29,402,029	-	-	29,402,029	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		6,941,045,946	5,909,808	(4,068,928)	6,942,886,826	(303,139)	(4,068,928)	6,938,514,759	123,052	(4,068,928)
<b>Hydro Production Plant:</b>										
Pre-merger Pacific	SG	183,221,776	-	(50,121)	183,171,656	-	(50,121)	183,121,535	-	(50,121)
Pre-merger Utah	SG	39,470,725	-	(32,867)	39,437,858	-	(32,867)	39,404,991	-	(32,867)
Post-merger	SG-P	685,422,405	382,356	(183,427)	685,621,333	7,223,889	(183,427)	692,661,794	371,360	(183,427)
Post-merger	SG-U	161,457,546	1,162,945	(37,209)	162,583,282	(64,385)	(37,209)	162,481,687	(64,385)	(37,209)
Klamath - New Capital	SG-P	4,171,133	-	-	4,171,133	-	-	4,171,133	-	-
Klamath	SG-P	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant		1,165,248,176	1,545,301	(303,624)	1,166,489,852	7,159,503	(303,624)	1,173,345,731	306,975	(303,624)
<b>Other Production Plant:</b>										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,958,550,147	222,194	(2,040,058)	1,956,732,283	(17,642)	(2,040,058)	1,954,674,583	(17,642)	(2,040,058)
Post-merger Wind	SG-W	3,240,357,392	1,241,001	(238,555)	3,241,359,838	1,241,001	(238,555)	3,242,362,283	1,241,001	(238,555)
Black Cap Solar	OR	360,189	5,019	-	365,207	5,019	-	370,226	5,019	-
Post-merger	SG	89,778,232	4,057	(46,204)	89,736,085	4,057	(46,204)	89,693,938	4,057	(46,204)
Total Other Plant		5,289,281,089	1,472,271	(2,324,817)	5,288,428,542	1,232,435	(2,324,817)	5,287,336,160	1,232,435	(2,324,817)
<b>Transmission Plant:</b>										
Pre-merger Pacific	SG	477,783,329	-	(168,182)	477,615,146	-	(168,182)	477,446,964	-	(168,182)
Pre-merger Utah	SG	617,127,958	-	(295,470)	616,832,489	-	(295,470)	616,537,019	-	(295,470)
Post-merger	SG	6,764,681,518	39,318,077	(726,705)	6,803,272,890	16,541,889	(726,705)	6,819,088,074	16,819,653	(726,705)
Total Transmission Plant		7,859,592,805	39,318,077	(1,190,357)	7,897,720,525	16,541,889	(1,190,357)	7,913,072,057	16,819,653	(1,190,357)
<b>Distribution Plant:</b>										
California	CA	325,357,002	5,098,095	(145,707)	330,309,390	883,260	(145,707)	331,046,942	969,518	(145,707)
Oregon	OR	2,431,380,183	12,301,614	(1,763,593)	2,441,918,204	7,591,643	(1,763,593)	2,447,746,254	11,803,387	(1,763,593)
Washington	WA	590,028,062	19,873,165	(198,825)	609,702,402	1,837,494	(198,825)	611,341,070	1,242,842	(198,825)
Eastern Wyoming	WYP	704,897,274	2,076,540	(271,721)	706,702,093	2,366,401	(271,721)	708,796,773	2,182,224	(271,721)
Utah	UT	3,557,792,964	18,233,410	(1,414,241)	3,574,612,134	16,641,242	(1,414,241)	3,589,839,134	15,745,098	(1,414,241)
Idaho	ID	429,549,241	2,174,813	(155,146)	431,568,909	2,182,875	(155,146)	433,596,638	2,906,244	(155,146)
Western Wyoming	WYU	154,717,568	-	(27,785)	154,689,783	-	(27,785)	154,661,999	-	(27,785)
Total Distribution Plant		8,193,722,295	59,757,637	(3,977,018)	8,249,502,914	31,502,914	(3,977,018)	8,277,028,811	34,849,313	(3,977,018)

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Description	Factor	Adjusted			Adjusted			Adjusted		
		EPIS Balance Jun 2022	Capital Additions	Retirements	EPIS Balance Jul 2022	Capital Additions	Retirements	EPIS Balance Aug 2022	Capital Additions	Retirements
<b>General Plant:</b>										
California	CA	23,028,594	117,793	(43,689)	23,102,698	365,857	(43,689)	23,424,866	136,821	(43,689)
Oregon	OR	236,796,644	1,098,838	(323,194)	237,572,288	763,850	(323,194)	238,012,944	1,106,018	(323,194)
Washington	WA	49,023,713	186,183	(115,214)	49,094,682	100,890	(115,214)	49,080,358	380,123	(115,214)
Eastern Wyoming	WYP	90,342,257	349,396	(254,299)	90,437,355	758,302	(254,299)	90,941,358	440,710	(254,299)
Utah	UT	264,810,245	2,798,500	(479,305)	267,129,440	1,796,913	(479,305)	268,447,047	2,336,534	(479,305)
Idaho	ID	53,610,977	152,450	(68,917)	53,694,511	219,105	(68,917)	53,844,700	167,053	(68,917)
Western Wyoming	WYU	17,820,467	-	(31,708)	17,788,760	-	(31,708)	17,757,052	-	(31,708)
Pre-merger Pacific	SG	840,308	-	(13,917)	826,391	-	(13,917)	812,474	-	(13,917)
Pre-merger Utah	SG	2,452,655	-	(30,778)	2,421,877	-	(30,778)	2,391,098	-	(30,778)
Post-merger	SG	305,008,570	307,257	(578,398)	304,737,429	298,382	(578,398)	304,457,412	645,034	(578,398)
General Office	SO	395,319,434	1,667,125	(1,303,426)	395,683,133	1,131,538	(1,303,426)	395,511,244	1,941,818	(1,303,426)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	223,232	-	-	223,232	-	-	223,232	-	-
Customer Service	CN	16,102,447	-	(99,428)	16,003,019	-	(99,428)	15,903,591	-	(99,428)
Fuel Related	SE	3,139,927	-	(14,898)	3,125,029	-	(14,898)	3,110,131	-	(14,898)
Total General Plant		1,458,519,471	6,677,543	(3,357,172)	1,461,839,842	5,434,837	(3,357,172)	1,463,917,508	7,154,111	(3,357,172)
<b>Mining Plant:</b>										
Coal Mine	SE	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant		1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
<b>Intangible Plant:</b>										
California	CA	481,167	-	-	481,167	-	-	481,167	-	-
Customer Service	CN	213,838,449	-	(34,194)	213,804,255	-	(34,194)	213,770,061	-	(34,194)
Pre-merger Utah	SG	477,596	-	-	477,596	-	-	477,596	-	-
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,370,110	-	(86)	4,370,024	-	(86)	4,369,938	-	(86)
Oregon	OR	4,611,642	-	(363)	4,611,279	-	(363)	4,610,916	-	(363)
Fuel Related	SE	(39,847)	-	(4,079)	(43,926)	-	(4,079)	(48,006)	-	(4,079)
Post-merger	SG	209,928,115	-	(62,928)	209,865,187	-	(62,928)	209,802,260	-	(62,928)
Klamath Hydro Relicensing	SG-P	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-
Hydro Relicensing	SG-P	103,399,088	-	(4,666)	103,394,422	-	(4,666)	103,389,757	-	(4,666)
Hydro Relicensing	SG-U	9,835,852	-	(14,920)	9,820,931	-	(14,920)	9,806,011	-	(14,920)
General Office	SO	462,287,436	802,300	(1,123,079)	461,966,656	739,350	(1,123,079)	461,582,927	4,718,441	(1,123,079)
Utah	UT	(26,169,335)	-	(561)	(26,169,897)	-	(561)	(26,170,458)	-	(561)
Washington	WA	2,036,986	-	-	2,036,986	-	-	2,036,986	-	-
Eastern Wyoming	WYP	5,576,237	-	(7,729)	5,568,509	-	(7,729)	5,560,780	-	(7,729)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,064,745,246	802,300	(1,252,606)	1,064,294,941	739,350	(1,252,606)	1,063,781,685	4,718,441	(1,252,606)
<b>Total</b>		<b>31,973,977,929</b>	<b>115,482,937</b>	<b>(16,474,521)</b>	<b>32,072,986,344</b>	<b>62,307,789</b>	<b>(16,474,521)</b>	<b>32,118,819,612</b>	<b>65,203,980</b>	<b>(16,474,521)</b>



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Description	Factor	Adjusted			Adjusted			Adjusted		
		EPIS Balance Sep 2022	Capital Additions	Retirements	EPIS Balance Oct 2022	Capital Additions	Retirements	EPIS Balance Nov 2022	Capital Additions	Retirements
<b>Steam Production Plant:</b>										
Pre-merger Pacific	SG	1,006,311,917	-	(411,968)	1,005,899,948	-	(411,968)	1,005,487,980	-	(411,968)
Pre-merger Utah	SG	1,051,096,204	-	(538,554)	1,050,557,650	-	(538,554)	1,050,019,095	-	(538,554)
Post-merger	SG	4,846,491,883	4,107,487	(3,118,406)	4,847,480,964	7,789,652	(3,118,406)	4,852,152,210	15,967,861	(3,118,406)
Geothermal - Blundell	SG	29,402,029	-	-	29,402,029	-	-	29,402,029	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		6,934,568,884	4,107,487	(4,068,928)	6,934,607,442	7,789,652	(4,068,928)	6,938,328,166	15,967,861	(4,068,928)
<b>Hydro Production Plant:</b>										
Pre-merger Pacific	SG	183,071,414	-	(50,121)	183,021,293	-	(50,121)	182,971,172	-	(50,121)
Pre-merger Utah	SG	39,372,124	-	(32,867)	39,339,257	-	(32,867)	39,306,390	-	(32,867)
Post-merger	SG-P	692,849,727	1,594,764	(183,427)	694,261,064	5,297,767	(183,427)	699,375,404	27,913,365	(183,427)
Post-merger	SG-U	162,380,093	3,433,801	(37,209)	165,776,684	(15,698)	(37,209)	165,723,777	17,600,024	(37,209)
Klamath - New Capital	SG-P	4,171,133	-	-	4,171,133	3,493,814	-	7,664,947	1,982,716	-
Klamath	SG-P	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant		1,173,349,082	5,028,565	(303,624)	1,178,074,023	8,775,883	(303,624)	1,186,546,282	47,496,104	(303,624)
<b>Other Production Plant:</b>										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,952,616,883	2,797,495	(2,040,058)	1,953,374,320	(17,642)	(2,040,058)	1,951,316,621	6,850,016	(2,040,058)
Post-merger Wind	SG-W	3,243,364,729	1,241,001	(238,555)	3,244,367,175	1,241,001	(238,555)	3,245,369,621	1,241,001	(238,555)
Black Cap Solar	OR	375,245	5,019	-	380,264	5,019	-	385,282	5,019	-
Post-merger	SG	89,651,791	4,057	(46,204)	89,609,644	4,057	(46,204)	89,567,497	66,643	(46,204)
Total Other Plant		5,286,243,778	4,047,572	(2,324,817)	5,287,966,533	1,232,435	(2,324,817)	5,286,874,150	8,162,679	(2,324,817)
<b>Transmission Plant:</b>										
Pre-merger Pacific	SG	477,278,782	-	(168,182)	477,110,600	-	(168,182)	476,942,418	-	(168,182)
Pre-merger Utah	SG	616,241,549	-	(295,470)	615,946,080	-	(295,470)	615,650,610	-	(295,470)
Post-merger	SG	6,835,181,021	31,397,739	(726,705)	6,865,852,054	41,961,513	(726,705)	6,907,086,862	45,595,977	(726,705)
Total Transmission Plant		7,928,701,352	31,397,739	(1,190,357)	7,958,908,734	41,961,513	(1,190,357)	7,999,679,890	45,595,977	(1,190,357)
<b>Distribution Plant:</b>										
California	CA	331,870,753	2,186,679	(145,707)	333,911,724	1,818,654	(145,707)	335,584,670	6,759,818	(145,707)
Oregon	OR	2,457,786,048	7,523,232	(1,763,593)	2,463,545,688	6,128,702	(1,763,593)	2,467,910,797	18,180,922	(1,763,593)
Washington	WA	612,385,087	1,486,512	(198,825)	613,672,774	1,323,512	(198,825)	614,797,460	4,812,800	(198,825)
Eastern Wyoming	WYP	710,707,276	1,978,437	(271,721)	712,413,993	1,830,723	(271,721)	713,972,995	2,309,427	(271,721)
Utah	UT	3,604,169,991	23,423,617	(1,414,241)	3,626,179,367	26,789,820	(1,414,241)	3,651,554,946	21,186,314	(1,414,241)
Idaho	ID	436,347,737	2,227,970	(155,146)	438,420,561	1,954,840	(155,146)	440,220,256	4,278,631	(155,146)
Western Wyoming	WYU	154,634,214	-	(27,785)	154,606,429	-	(27,785)	154,578,645	-	(27,785)
Total Distribution Plant		8,307,901,106	38,826,448	(3,977,018)	8,342,750,536	39,846,251	(3,977,018)	8,378,619,770	57,527,912	(3,977,018)

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Description	Factor	Adjusted			Adjusted			Adjusted		
		EPIS Balance Sep 2022	Capital Additions	Retirements	EPIS Balance Oct 2022	Capital Additions	Retirements	EPIS Balance Nov 2022	Capital Additions	Retirements
<b>General Plant:</b>										
California	CA	23,517,998	109,665	(43,689)	23,583,975	90,292	(43,689)	23,630,578	373,498	(43,689)
Oregon	OR	238,795,768	1,003,203	(323,194)	239,475,776	1,482,161	(323,194)	240,634,743	3,874,044	(323,194)
Washington	WA	49,345,267	122,681	(115,214)	49,352,734	90,771	(115,214)	49,328,290	449,890	(115,214)
Eastern Wyoming	WYP	91,127,770	554,524	(254,299)	91,427,995	1,117,617	(254,299)	92,291,313	1,418,787	(254,299)
Utah	UT	270,304,276	2,332,590	(479,305)	272,157,560	2,089,994	(479,305)	273,768,249	4,451,347	(479,305)
Idaho	ID	53,942,836	219,365	(68,917)	54,093,284	286,015	(68,917)	54,310,382	643,626	(68,917)
Western Wyoming	WYU	17,725,345	-	(31,708)	17,693,637	-	(31,708)	17,661,930	-	(31,708)
Pre-merger Pacific	SG	798,556	-	(13,917)	784,639	-	(13,917)	770,722	-	(13,917)
Pre-merger Utah	SG	2,360,320	-	(30,778)	2,329,541	-	(30,778)	2,298,763	-	(30,778)
Post-merger	SG	304,524,048	796,661	(578,398)	304,742,310	1,921,945	(578,398)	306,085,857	6,185,528	(578,398)
General Office	SO	396,149,636	4,730,508	(1,303,426)	399,576,717	1,540,371	(1,303,426)	399,813,661	8,214,484	(1,303,426)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	223,232	-	-	223,232	-	-	223,232	-	-
Customer Service	CN	15,804,162	-	(99,428)	15,704,734	-	(99,428)	15,605,305	-	(99,428)
Fuel Related	SE	3,095,234	-	(14,898)	3,080,336	-	(14,898)	3,065,439	-	(14,898)
Total General Plant		1,467,714,447	9,869,196	(3,357,172)	1,474,226,471	8,619,164	(3,357,172)	1,479,488,463	25,611,205	(3,357,172)
<b>Mining Plant:</b>										
Coal Mine	SE	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant		1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
<b>Intangible Plant:</b>										
California	CA	481,167	-	-	481,167	-	-	481,167	-	-
Customer Service	CN	213,735,868	-	(34,194)	213,701,674	-	(34,194)	213,667,480	-	(34,194)
Pre-merger Utah	SG	477,596	-	-	477,596	-	-	477,596	-	-
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,369,851	-	(86)	4,369,765	-	(86)	4,369,679	-	(86)
Oregon	OR	4,610,553	-	(363)	4,610,189	-	(363)	4,609,826	-	(363)
Fuel Related	SE	(52,085)	-	(4,079)	(56,164)	-	(4,079)	(60,244)	-	(4,079)
Post-merger	SG	209,739,332	-	(62,928)	209,676,404	-	(62,928)	209,613,477	-	(62,928)
Klamath Hydro Relicensing	SG-P	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-
Hydro Relicensing	SG-P	103,385,091	-	(4,666)	103,380,425	-	(4,666)	103,375,760	-	(4,666)
Hydro Relicensing	SG-U	9,791,091	-	(14,920)	9,776,170	-	(14,920)	9,761,250	-	(14,920)
General Office	SO	465,178,289	647,880	(1,123,079)	464,703,089	2,532,110	(1,123,079)	466,112,120	11,799,593	(1,123,079)
Utah	UT	(26,171,019)	-	(561)	(26,171,581)	-	(561)	(26,172,142)	-	(561)
Washington	WA	2,036,986	-	-	2,036,986	-	-	2,036,986	-	-
Eastern Wyoming	WYP	5,553,052	-	(7,729)	5,545,323	-	(7,729)	5,537,594	-	(7,729)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,067,247,521	647,880	(1,252,606)	1,066,642,795	2,532,110	(1,252,606)	1,067,922,300	11,799,593	(1,252,606)
<b>Total</b>		<b>32,167,549,070</b>	<b>93,924,886</b>	<b>(16,474,521)</b>	<b>32,244,999,434</b>	<b>110,757,008</b>	<b>(16,474,521)</b>	<b>32,339,281,921</b>	<b>212,161,332</b>	<b>(16,474,521)</b>

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Description	Factor	Adjusted	End of Period
		EPIS Balance Dec 2022	December 2022 Test Period Balance
<b>Steam Production Plant:</b>			
Pre-merger Pacific	SG	1,005,076,012	1,005,076,012
Pre-merger Utah	SG	1,049,480,541	1,049,480,541
Post-merger	SG	4,865,001,665	4,865,001,665
Geothermal - Blundell	SG	29,402,029	29,402,029
Pollution Control Equipment	SG	-	-
Pollution Control Equipment	SG	-	-
Pollution Control Equipment	SG	-	-
Post-merger - Cholla	SG	1,266,851	1,266,851
Total Steam Plant		<u>6,950,227,099</u>	<u>6,950,227,099</u>
<b>Hydro Production Plant:</b>			
Pre-merger Pacific	SG	182,921,052	182,921,052
Pre-merger Utah	SG	39,273,524	39,273,524
Post-merger	SG-P	727,105,341	727,105,341
Post-merger	SG-U	183,286,592	183,286,592
Klamath - New Capital	SG-P	9,647,664	9,647,664
Klamath	SG-P	91,504,591	91,504,591
Total Hydro Plant		<u>1,233,738,762</u>	<u>1,233,738,762</u>
<b>Other Production Plant:</b>			
Pre-merger Utah	SG	235,129	235,129
Post-merger	SG	1,956,126,579	1,956,126,579
Post-merger Wind	SG-W	3,246,372,067	3,246,372,067
Black Cap Solar	OR	390,301	390,301
Post-merger	SG	89,587,935	89,587,935
Total Other Plant		<u>5,292,712,012</u>	<u>5,292,712,012</u>
<b>Transmission Plant:</b>			
Pre-merger Pacific	SG	476,774,235	476,774,235
Pre-merger Utah	SG	615,355,140	615,355,140
Post-merger	SG	6,951,956,134	6,951,956,134
Total Transmission Plant		<u>8,044,085,510</u>	<u>8,044,085,510</u>
<b>Distribution Plant:</b>			
California	CA	342,198,781	342,198,781
Oregon	OR	2,484,328,127	2,484,328,127
Washington	WA	619,411,435	619,411,435
Eastern Wyoming	WYP	716,010,701	716,010,701
Utah	UT	3,671,327,019	3,671,327,019
Idaho	ID	444,343,741	444,343,741
Western Wyoming	WYU	154,550,860	154,550,860
Total Distribution Plant		<u>8,432,170,664</u>	<u>8,432,170,664</u>

**PacifiCorp  
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Description	Factor	Adjusted	End of Period
		EPIS Balance Dec 2022	December 2022 Test Period Balance
<b>General Plant:</b>			
California	CA	23,960,387	23,960,387
Oregon	OR	244,185,593	244,185,593
Washington	WA	49,662,967	49,662,967
Eastern Wyoming	WYP	93,455,801	93,455,801
Utah	UT	277,740,291	277,740,291
Idaho	ID	54,885,092	54,885,092
Western Wyoming	WYU	17,630,222	17,630,222
Pre-merger Pacific	SG	756,805	756,805
Pre-merger Utah	SG	2,267,985	2,267,985
Post-merger	SG	311,692,986	311,692,986
General Office	SO	406,724,719	406,724,719
General Office	SG	-	-
General Office	SG	223,232	223,232
Customer Service	CN	15,505,877	15,505,877
Fuel Related	SE	3,050,541	3,050,541
Total General Plant		<u>1,501,742,497</u>	<u>1,501,742,497</u>
<b>Mining Plant:</b>			
Coal Mine	SE	1,822,901	1,822,901
Total Mining Plant		<u>1,822,901</u>	<u>1,822,901</u>
<b>Intangible Plant:</b>			
California	CA	481,167	481,167
Customer Service	CN	213,633,287	213,633,287
Pre-merger Utah	SG	477,596	477,596
Pre-merger Pacific	SG	-	-
Idaho	ID	4,369,593	4,369,593
Oregon	OR	4,609,463	4,609,463
Fuel Related	SE	(64,323)	(64,323)
Post-merger	SG	209,550,549	209,550,549
Klamath Hydro Relicensing	SG-P	74,111,750	74,111,750
Hydro Relicensing	SG-P	103,371,094	103,371,094
Hydro Relicensing	SG-U	9,746,329	9,746,329
General Office	SO	476,788,634	476,788,634
Utah	UT	(26,172,704)	(26,172,704)
Washington	WA	2,036,986	2,036,986
Eastern Wyoming	WYP	5,529,866	5,529,866
Western Wyoming	WYU	-	-
Total Intangible Plant		<u>1,078,469,287</u>	<u>1,078,469,287</u>
<b>Total</b>		<u><u>32,534,968,731</u></u>	<u><u>32,534,968,731</u></u>

Ref. 8.5.4

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Pro Forma Plant Additions**  
**Steam Plant Additions**

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22		Ref.
				Plant Adds		
U0 Huntington Water Redirect; U0 Land Application Conversion D	312	SG	Oct-21	12,627,976		8.4.28
Wyodak U1 - Boiler Waterwall Replacement CY21/CY22	312	SG	May-22	3,871,573		
Colstrip 3-4: Design/Build Dry Waste	312	SG	Jul-22	3,755,217		
Hunter 301 HP/IP/LP Turbine Overhaul	312	SG	Apr-22	3,368,292		
Dave Johnston U4 - Retube Condenser	312	SG	May-22	3,196,216		
Wyodak U1 - Replacement of Turbine HP Rotor CY2	312	SG	May-22	3,098,322		
Naughton U1 OH Turbine Major (HP/IP/LP) CY22	312	SG	May-22	3,093,440		
Wyodak U1 - HP/IP Turbine Overhaul CY22	312	SG	May-22	2,844,080		
Hunter 301 Replace Scrubber Outlet Header Duct	312	SG	Apr-22	2,798,490		
Huntington U1 Boiler Rear Reheat Header & Terminal Tubes	312	SG	Oct-22	2,754,488		
Wyodak U1 - Expansion Joint Replace CY21/CY22	312	SG	Apr-22	2,053,232		
Hunter 301 Scrubber Component Overhaul	312	SG	Apr-22	1,929,947		
Gadsby U2 Cooling Tower Replacement	312	SG	May-22	1,896,045		
Hunter 301 Generator Exciter Rewind	312	SG	Apr-22	1,632,781		
Dave Johnston U0 - MILL BLANKET - 2022	312	SG	Various	1,625,476		
Naughton U1 OH Mechanical Dust Collectors CY20	312	SG	May-22	1,621,240		
Hunter 301 SH Division Panel Replacements	312	SG	Apr-22	1,526,203		
Jim Bridger U2 Burners Major 22	312	SG	Jun-22	1,490,848		
Huntington U1 Burner Corner Coal Nozzle & Tip replacement	312	SG	Nov-22	1,483,079		
Dave Johnston U0 - PUMPS AND VALVES - 2022	312	SG	Various	1,395,788		
Huntington U1 LP Turbine Component Replacement	312	SG	Nov-22	1,329,919		
Hunter 301 Burner Tips and Nozzles	312	SG	Apr-22	1,087,793		
Dave Johnston U0 - MILL BLANKET - 2021	312	SG	Various	1,077,176		
Wyodak U1 - Pulverizer Overhaul "B" CY22	312	SG	May-22	1,037,950		
Projects Less Than \$1million	312	SG	Various	102,876,042		
Projects Less Than \$1million - Cholla	312	SSGCH	Various	-		
Steam Plant Five Year Average Removals	312	SG		(26,028,982)		
				<u>139,442,631</u>		

**PacifiCorp  
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Hydro Plant Additions**

<b>Project Description</b>	<b>FERC Account</b>	<b>Factor</b>	<b>Inservice Date</b>	<b>July21 to Dec22 Plant Adds</b>	<b>Ref.</b>
PP Hydro West	332	SG-P	Various	17,546,469	
Merwin Downstream In-Lieu	332	SG-P	Dec-22	14,144,756	<b>8.4.28</b>
PP Hydro East	332	SG-U	Various	10,267,241	
ILR 4.1.9 Future Fish Passage Stage 1 Ph	332	SG-P	Jun-22	9,478,781	
Yale Saddle Dam Seismic Remediation	332	SG-P	Various	7,452,707	
PP Hydro Impl On-Proj West	332	SG-P	Various	7,034,218	
Toketee Dam Rehabilitation	332	SG-P	Dec-21	5,417,562	
Cutler Surge Tank Anchor Upgrades	332	SG-U	Dec-22	4,979,273	
Soda Spinning Reserve	332	SG-U	Dec-22	4,368,628	
Toketee 2 Turbine Refurbishment	332	SG-P	Dec-22	3,515,432	
Iron Gate Bridge K6 Life Extension	332	SG-P	Nov-22	3,453,066	
PP Hydro Plant JA	332	SG-P	Various	3,341,354	
PP Other Hydro Dam Safety West	332	SG-P	Various	2,811,412	
PP Other Hydro Dam Safety JA	332	SG-P	Various	2,186,344	
Cutler Surge Tank Anchor Upgrades	332	SG-U	Dec-21	2,026,064	
Iron Gate CSIR Mandated Improvements 2020	332	SG-P	Dec-22	1,955,135	
ILR 11.2.2.12 Beaver Bay PH 1 Renovation	332	SG-P	Dec-22	1,782,000	
Cutler Flowline Coating Replacement 2021	332	SG-U	Dec-21	1,675,693	
Ashton Trash Rake Construction	332	SG-U	Dec-22	1,620,000	
Oneida Switchgear	332	SG-U	Oct-22	1,593,921	
SWIFT 1 SPARE GSU REPLACEMENT	332	SG-P	Feb-22	1,458,000	
Toketee Flowline Isolation Valve	332	SG-P	Oct-21	1,368,918	
Bigfork Fish Screen Rake	332	SG-U	Jul-22	1,227,330	
Weber Dam Improvements Evaluation	332	SG-U	Dec-22	1,178,220	
PP Other Hydro Dam Safety East	332	SG-U	Various	1,140,601	
Merwin 2 Intake Screen Replacement	332	SG-P	Dec-21	1,051,113	
Prospect North Fork Trash Rack Improvement	332	SG-P	Feb-22	1,010,917	
Projects Less Than \$1million	332	SG-P	Various	3,976,099	
Projects Less Than \$1million	332	SG-U	Various	2,141,705	
Hydro Plant Five Year Average Removals	332	SG-U		(1,158,934)	
Hydro Plant Five Year Average Removals	332	SG-P		(1,596,134)	
				<u>118,447,892</u>	

**PacifiCorp**  
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**Pro Forma Plant Additions**  
**Other Plant Additions**

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22	Ref.
				Plant Adds	
TB Flats Wind Project 500 MW 2020	343	SG-W	Various	54,196,091	8.4.28
Currant Creek U2 CSA Variable Fee 32k - CTB MI	343	SG	Oct-21	12,742,259	8.4.28
Currant Creek U1 CSA Variable Fee 32k - CTA MI	343	SG	Oct-21	12,734,888	8.4.29
Chehalis U1 CSA Variable fee - CT1 - HGP	343	SG	Apr-22	11,723,088	8.4.29
Chehalis U2 CSA Variable fee - CT2 - HGP	343	SG	Apr-22	11,693,774	8.4.29
Pryor Mtn Wind Project 240 MW 2020	343	SG-W	Various	11,120,326	8.4.29
PP Wind Production	343	SG-W	Various	6,891,562	
Footo Creek Repowering	343	SG-W	Various	5,533,249	
Hermiston U2 Overhaul Capital CY23 MI	343	SG	Dec-22	4,670,914	
Hermiston U0 Capital Spares 12K Parts	343	SG	Oct-22	2,321,337	
PP Eagle Mitigation	343	SG-W	Various	2,136,539	
Gadsby U6 Stage 1 HPT blade replacement 191-364	343	SG	Sep-21	1,464,254	
Gadsby U6 Stage 2 HPT blade replacement 191-364	343	SG	Jul-21	1,310,335	
Chehalis U3 RT Lite Valve Replacement	343	SG	May-22	1,050,959	
Projects Less Than \$1million	343	SG	Various	11,707,167	
Projects Less Than \$1million	343	SG-W	Various	11,344,707	
Projects Less Than \$1million - Situs OR	343	OR	Various	315,315	
Projects Less Than \$1million - Seasonal SSGCT	343	SG	Various	2,004,803	
Other Plant Five Year Average Removals	343	SG		(1,766,276)	
Other Plant - Wind Five Year Average Removals	343	SG		(1,352,633)	
				<u>161,842,657</u>	

**PacifiCorp**  
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**Pro Forma Plant Additions**  
**Transmission Plant Additions**

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22	
				Plant Adds	Ref.
Pacific Power Transmission Replacements	355	SG	various	29,346,318	
Transmission Customer New Revenue East	355	SG	Various	24,921,999	
Goshen-Sugarmill-Rigby 161kV Trans Line- Trans	355	SG	Jul-22	23,237,498	8.4.29
Jordanelle - Midway Construct 138 kV Line - Trans	355	SG	Dec-21	21,938,510	8.4.30
Rocky Mountain Power 2021 Trans Investment Programs	355	SG	Various	19,712,244	
Klamath Falls - Snow Goose 230 kV Line No. 2 TPL	355	SG	Nov-22	17,335,128	8.4.30
Utah Transmission BLM & Other ROW Renewals	355	SG	Various	16,658,532	
Rexburg Sub - Inst 161kV Source from Rigby	355	SG	Nov-21	16,521,644	8.4.30
Pacific Power Transmission Wildfire Mitigation Projects	355	SG	various	14,942,038	8.4.30
Pacific Power Sub-Trans/Major Sub System Upgrades	355	SG	Various	14,383,367	
Rocky Mountain Power Transmission Wildfire Mitigation	355	SG	Various	13,607,812	8.4.31
Transmission Customer New Revenue West	355	SG	Various	13,038,073	
Jim Bridger 345-230 kV Transformer 2 Upgrade	355	SG	Oct-21	13,013,486	8.4.31
Transmission Customer System Upgrade East	355	SG	Various	12,785,002	
Transmission Main Grid System Upgrades East	355	SG	Various	9,317,726	
Jordan Valley - Commercial Load	355	SG	Dec-21	7,764,347	
Magna Cap and Tooele - Pine Cyn Rebuild 138kV	355	SG	Dec-22	6,016,322	
Transmission Main Grid System West	355	SG	Various	5,595,414	
Bear River 138kV Conversion	355	SG	Dec-22	5,323,100	
Tucker 69 kV Tie Line	355	SG	Nov-22	5,174,101	
Utah Transmission Replace Sub Switchgear, Breakers, Reclosers	355	SG	Various	5,157,710	
Flint New 115kV to 12.5kV Substation Project- Trans	355	SG	Apr-22	5,152,491	
Lebanon Loop Reliability Upgrade Project (Weirich) Phase 1	355	SG	Sep-21	4,999,751	
Goshen #3 35/161 kV 400 MVA Transformer Install TPL	355	SG	Aug-22	4,800,894	
Utah Transmission Replace - Storm & Casualty	355	SG	Various	4,599,668	
Line 39 Reconductor	355	SG	Sep-21	4,552,011	
Douglas - Construct 115kV Line	355	SG	Sep-22	4,481,073	
St Johns (BPA) to Knott 115kV Line Conversion Project	355	SG	Oct-22	4,171,780	
Utah Replace Overhead Transmission Poles	355	SG	Various	3,849,292	
RMP Grid Resilience Replacement 345-138kV 700MVA XFMR	355	SG	Dec-21	3,809,892	
Huntington U0 Universal Spare GSU Huntington Plant	355	SG	Nov-22	3,418,537	
Cross Hollows Install 2nd Xfmr - Trans	355	SG	May-22	3,373,396	
Klamath Falls -Hornet 69 kv line 9, Reconductor 5.3 miles T	355	SG	Sep-22	3,053,014	
Reroute JB Goshen 345kV line for Slide: IPC Shared	355	SG	Oct-22	2,926,466	
Hunter 301 Spare Main GSU Replacement	355	SG	Oct-22	2,814,940	
Outlook Sub Rpl Transf 321065 (T2134)	355	SG	Dec-21	2,802,256	
BLM Sigurd-Glen Canyon	355	SG	Jul-22	2,761,639	
Nickel Mtn Sub: Replace TRF3512(324647)	355	SG	Dec-21	2,705,966	
Utah Transmission SF6 - Circuit Breaker Replacements	355	SG	Various	2,431,375	
115 kV Tillamook-Astoria Insp & Repl Suspension Insul	355	SG	Dec-22	2,394,879	
Pacific Power Spare Transmission 230-69kV Transformer Purchase	355	SG	Sep-21	2,360,613	
Utah Transmission CAPEX Condition Correction	355	SG	Various	2,278,002	
Vantage - Pomona Heights - TPL002	355	SG	Various	2,246,043	
Wyoming Replace Transmission Conductor/Armor Rod	355	SG	Various	2,230,361	
RMP Replace 345-230kV 450 MVA XFMR	355	SG	Sep-22	2,184,728	
RMP Storage Yard Site Development	355	SG	Dec-21	2,150,991	
Populus - Terminal 345 kV line - condemnation settlements	355	SG	Various	2,109,518	
Wyoming Replace Overhead Transmission Poles	355	SG	Various	2,025,943	
Utah Transmission Line Improvements - Other	355	SG	Various	1,772,357	
Pacific Power Transmission New Connects	355	SG	various	1,731,815	
Pacific Power Spare Transmission 115-69kV Transformer Purchase	355	SG	Oct-21	1,713,625	
Utah Transmission Replace Substation Transformers	355	SG	Various	1,624,527	
Wyoming Transmission BLM & Other ROW Renewals	355	SG	Various	1,582,146	
BLM Helper-Moab	355	SG	Dec-22	1,556,706	
Taylorville-Granger East Tap 46 kV line Rebuild	355	SG	May-22	1,553,292	
Utah Transmission Replace Sub Bushings, Glass & Other	355	SG	Various	1,520,478	
Pacific Power Transmission Line Reliability Linescope projects	355	SG	Oct-21	1,484,798	
Alturas Replace 115-69kV Transformer Bank	355	SG	Dec-22	1,400,000	
Price City Tap to Helper Rebuild	355	SG	Dec-21	1,390,603	
Aeolus-Bridger/Anticline 500 kV Line	355	SG	Various	1,354,411	
Idaho Transmission Replace - Storm & Casualty	355	SG	Various	1,272,931	
Idaho Replace Overhead Transmission Lines - Other	355	SG	Various	1,267,250	
Idaho Power 2021 Emergent Capital Work	355	SG	Various	1,121,107	
Southeast - Install New Control Building	355	SG	Dec-21	1,028,614	
Idaho Power - Borah - Midpoint #1 replace wood w/ steel	355	SG	Various	1,027,822	
Idaho Replace Overhead Transmission Poles	355	SG	Various	1,012,972	
Utah Transmission Protection Improvements	355	SG	Various	1,012,529	
Projects Less Than \$1million	355	SG	Various	19,529,764	
Transmission Five Year Average Removals	355	SG		(9,073,889)	
				<u>419,359,745</u>	



**PacifiCorp  
Oregon General Rate Case - December 2023  
Pro Forma Plant Additions  
Distribution Plant Additions**

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22	Ref.
				Plant Adds	
PP Distribution OR	364	OR	various	81,479,359	
PP Dist New Connect OR	364	OR	various	72,121,946	
AMI - Utah Meters 2019 -2020	364	UT	Dec-22	44,696,839	
Wildfire Mitigation - Dist	364	UT	Various	41,146,176	
Utah-New Connect - Residential	364	UT	Various	36,710,227	
RMPDistUT Investment Programs	364	UT	Various	36,134,794	
Wildfire - Dist - CA	364	CA	various	35,348,247	
RMPDist - NRUT Investment Programs	364	UT	Various	30,876,031	
Wildfire - Dist - OR	364	OR	various	27,237,149	8.4.31
Utah-New Connect - Commercial	364	UT	Various	19,993,879	
OR Distribution Major Projects	364	OR	Various	18,464,660	
PP Distribution WA	364	WA	various	18,215,506	
WA Distribution Major Projects	364	WA	Various	16,699,555	
AMI - Idaho 2019 meters	364	ID	Dec-22	14,372,112	
PP Dist New Connect CA	364	CA	various	13,277,942	
PP Dist New Connect WA	364	WA	various	12,469,790	
Rock Springs - Industrial Load	364	WYP	May-22	11,843,859	
U/G Cable Test & Replace	364	UT	Various	11,177,995	
Cedar City - Commercial Load	364	UT	May-22	10,046,845	
Jordan Valley - Install New Substation - Dist	364	UT	Mar-22	9,839,485	
Replace Underground Vaults & Equipment - UT	364	UT	Various	7,676,470	
Replace Overhead Distribution Poles - UT	364	UT	Various	7,649,912	
RMPDistWY Investment Programs	364	WYP	Various	7,606,011	
Wildfire - Dist - WA	364	WA	various	7,296,075	
PP Distribution CA	364	CA	various	6,854,974	
Replace Overhead Distribution Lines - Crossarms & Cutouts - UT Dist	364	UT	Various	6,753,788	
RMPDist - NRWY Investment Programs	364	WYP	Various	6,131,892	
Targeted reliability Improvement, Dist - UT	364	UT	Various	5,544,854	
Jordan Valley - Install 30 MVA Transformer - Dist	364	UT	Jun-22	5,484,788	
Mandated Highway Relocations - UT - D	364	UT	Various	5,294,509	
New Revenue - Feeder Reinforcement - UT	364	UT	Various	5,072,505	
Replace Underground Cable - UT	364	UT	Various	4,999,619	
RMPDistID Investment Programs	364	ID	Various	4,905,674	
American Fork - Install Second Transformer - Dist	364	UT	May-21	4,484,245	
RMPDist - NRID Investment Programs	364	ID	Various	4,284,523	
Replace - Storm & Casualty - UT Dist	364	UT	Various	4,267,437	
Idaho-New Connect - Residential	364	ID	Various	4,093,128	
Cedar City - Install New Dist Sub	364	UT	Dec-22	4,055,073	
Richfield - Industrial Load	364	UT	Dec-21	3,920,547	
Replace Overhead Distribution Lines - Other - UT	364	UT	Various	3,864,679	
UT - Increase Capacity - Dist	364	UT	Dec-22	3,754,346	
Wyoming-New Connect - Residential	364	WYP	Various	3,732,615	
New Connect Meter Purchases - UT	364	UT	Various	3,613,049	
Preston - Substation Transmission Breaker Additions	364	ID	Dec-21	3,287,982	
Jordan Valley - Substation Property Acquisition	364	UT	Jun-22	3,255,780	
CAPEX Condition Correction - Dist - UT	364	UT	Various	3,182,574	
Mobile #6 Replace Failed 138-69kV Transformer	364	UT	Nov-22	3,036,362	
Avian Protection - Dist WY	364	WYP	Various	2,977,553	
Jordan Valley - Commercial Load	364	UT	May-22	2,909,079	
Wildfire Storm Costs Dist OR	364	OR	various	2,657,313	
Metro - Commercial Load	364	UT	May-22	2,652,629	
Replace Overhead Distribution Poles - ID	364	ID	Various	2,642,145	
Replace Overhead Distribution Lines - Crossarms & Cutouts - WY Dist	364	WYP	Various	2,373,454	
Layton - Commercial Load	364	UT	Nov-21	2,370,488	
Wyoming-New Connect - Commercial	364	WYP	Various	2,355,288	
Avian Protection - Dist UT	364	UT	Various	2,172,228	
Replace Underground Cable - WY	364	WYP	Various	2,080,411	
TPU/DPU Relay Replacement Program - UT	364	UT	Various	2,047,493	
Rexburg - Control Building Addition	364	ID	Dec-22	2,035,944	
Metro - Commercial Load	364	UT	Nov-22	2,027,680	
Linerupter Switch Replacement Program	364	ID	Various	1,994,178	
Tiller Sub-Replace Structures and Transformer	364	OR	Dec-21	1,966,419	
Replace Overhead Distribution Poles - WY	364	WYP	Various	1,931,145	

**PacifiCorp  
Oregon General Rate Case - December 2023  
Pro Forma Plant Additions  
Distribution Plant Additions**

<b>Project Description</b>	<b>FERC Account</b>	<b>Factor</b>	<b>Inservice Date</b>	<b>July21 to Dec22 Plant Adds</b>	<b>Ref.</b>
EX Utah Development, 19.03 MW Load	364	UT	Dec-22	1,929,655	
Avian Protection - Dist ID	364	ID	Various	1,882,696	
Cedar City - Install 2nd Xfmr - Dist	364	UT	May-22	1,722,451	
Madras SC: Buy three 500 & 230 kV GR Spare Ck Bkrs	364	OR	Dec-21	1,629,217	
Replace Substation Transformers - UT - D	364	UT	Various	1,602,445	
Pole Failure Mitigation - Porcelain Cutout Replacement - UT Dist	364	UT	Various	1,561,894	
Replace - Storm & Casualty - WY Dist	364	WYP	Various	1,433,267	
UT - Add Mobile Connection	364	UT	May-22	1,406,818	
Idaho-New Connect - Commercial	364	ID	Various	1,303,554	
Metro - 8kV System Upgrade - Dist	364	UT	Various	1,275,083	
Replace Overhead Distribution Lines - Other - WY	364	WYP	Various	1,169,363	
Metro - Commercial Load	364	UT	Jul-21	1,100,000	
Cedar City - Commercial Load	364	UT	May-22	1,084,448	
Replace - Storm & Casualty - ID Dist	364	ID	Various	1,082,460	
Replace Overhead Distribution Lines - Crossarms & Cutouts - ID Dist	364	ID	Various	1,077,585	
Neutral Extensions - WY	364	WYP	Various	1,022,388	
Metro - Commercial Load	364	UT	Apr-22	1,009,441	
Projects Less Than \$1million	364	CA	Various	43,522	
Projects Less Than \$1million	364	ID	Various	7,999,823	
Projects Less Than \$1million	364	OR	Various	-	
Projects Less Than \$1million	364	UT	Various	16,246,926	
Projects Less Than \$1million	364	WA	Various	-	
Projects Less Than \$1million	364	WYP	Various	8,595,845	
Distribution Plant Five Year Average Removals	364	CA		(1,087,989)	
Distribution Plant Five Year Average Removals	364	ID		(1,704,769)	
Distribution Plant Five Year Average Removals	364	OR		(14,165,176)	
Distribution Plant Five Year Average Removals	364	UT		(15,214,652)	
Distribution Plant Five Year Average Removals	364	WA		(3,077,675)	
Distribution Plant Five Year Average Removals	364	WYP		(4,413,224)	
				<u>749,964,651</u>	

**PacifiCorp  
Oregon General Rate Case - December 2023  
Pro Forma Plant Additions  
General Plant Additions**

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22	Ref.
				Plant Adds	
PP Core IT and TOM Hardware Equipment	397	SO	various	30,784,123	
AMI - IT Comm Network	397	SO	Dec-22	17,481,960	8.4.31
Replace Vehicles - UT	397	UT	Various	15,459,141	
Lloyd Center Tower Open Office	397	SO	various	12,706,413	8.4.31
AMI - Utah Field Area Network	397	UT	Dec-22	10,374,440	
PP Vehicles OR	397	OR	various	9,416,788	
PP Com Plant OR	397	OR	various	8,902,871	
AMI - Idaho IT Comm Network	397	SO	Dec-22	7,322,089	
Replace Vehicles - WY	397	WYP	Various	7,143,176	
WestSmart@Scale – EV Infrastructure	397	UT	Various	6,055,538	
PP Com Plant UT	397	UT	various	5,317,513	
PP Hydro Vehicles	397	SG	Various	4,496,952	
PP Hydro General Plant	397	SG	Various	3,605,449	
RMPGen - SitusUT Investment Programs	397	UT	Various	3,016,525	
PP Com Plant WY	397	WYP	various	2,835,003	
Replace Vehicles - ID	397	ID	Various	2,605,152	
PP Com Main Grid - East	397	SG	Aug-21	2,496,505	
PP Structures OR	397	OR	various	2,062,095	
Alcatel Lucent DMX-Nickel Mtn Glendale	397	OR	Dec-21	2,038,159	
Replace Other General Plant - UT	397	UT	Various	1,999,584	
RMPGen - Alloc Investment Programs	397	SO	Various	1,800,000	
Oracle Exadata/Shared hosting TOM	397	SO	May-22	1,713,600	
Monarch PAC6 Upgrade and HW TOM	397	SO	Nov-21	1,638,690	
Replace Other General Plant - WY	397	WYP	Various	1,498,172	
Replace Tools - UT	397	UT	Various	1,486,307	
Replace Vehicles - Electric Purchase	397	UT	Various	1,478,291	
Calapooya to Mckenzie Fiber Install	397	OR	Dec-21	1,432,013	
PP General Plant OR	397	OR	various	1,394,270	
Cutler to Rabbit Mtn MW Replacement	397	SG	Dec-22	1,344,468	
Dave Johnston U0 - Rebuild D10R Dozer	397	SG	Dec-22	1,326,659	
PP Vehicles WA	397	WA	various	1,324,054	
PP IT Business Requested Hardware Equipment	397	SO	various	1,225,195	
Wildfire Mitigation - Gen-Situs	397	UT	Various	1,200,272	
Alvey to McKenzie Fiber Install	397	SG	Dec-22	1,021,217	
PP Com Plant WA	397	WA	various	1,007,176	
Projects Less Than \$1million	397	CA	Various	1,636,111	
Projects Less Than \$1million	397	SG	Various	5,400,277	
Projects Less Than \$1million	397	ID	Various	2,133,024	
Projects Less Than \$1million	397	OR	Various	-	
Projects Less Than \$1million	397	SO	Various	6,369,167	
Projects Less Than \$1million	397	UT	Various	2,228,160	
Projects Less Than \$1million	397	WA	Various	551,491	
Projects Less Than \$1million	397	WYP	Various	1,039,896	
General Plant Five Year Average Removals	397	SO		(1,707,521)	
				<u>194,660,464</u>	

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Pro Forma Plant Additions**  
**Intangible Plant Additions**

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22	Ref.
				Plant Adds	
PP Core IT and TOM Software	303	SO	various	14,233,137	8.4.32
Maximo Phase 1A	303	SO	Jun-22	10,486,213	
CX Engagement	303	SO		9,248,663	
Monarch PAC6 Upgrade and HW TOM	303	SO	Nov-21	6,554,759	
Mapping Sys Consolidation	303	SO	Jan-22	3,672,800	
CX Communications	303	SO		3,436,541	
SunNet iTOA (Compass Repl)	303	SO	Dec-21	3,182,959	
PP IT Business Requested Software	302	SO	various	3,142,416	
UII RVN Replacement	303	SO	Jun-22	1,713,600	
ARCOS Callout Crew Availability System	303	SO	Aug-21	1,268,568	
Replace IAM-Scheduling/Tagging Power	303	SO	Sep-21	1,024,559	
Projects Less Than \$1million	303	OR	Various	-	
Projects Less Than \$1million	303	SO	Various	7,030,432	
				<u>64,994,648</u>	

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Plant Retirements**  
**5 Year Average Retirement Amount**

Function	Factor	CODE	FY2017 (CY2016) Retirements	FY2018 (CY2017) Retirements	FY2019 (CY2018) Retirements	FY2020 (CY2019) Retirements	FY2021 (CY2020) Retirements	Large Items to Exclude	5 Year Avg	Monthly Amount
STMP	DGU	STMPDGU	(60,466,542)	(3,295,196)	(3,805,358)	(27,141,648)	(2,191,253)	64,586,742	(6,462,651)	(538,554)
STMP	DGP	STMPDGP	(11,698,034)	(5,214,803)	(4,346,678)	(4,077,521)	(2,667,943)	3,286,891	(4,943,618)	(411,968)
STMP	SSGCH	STMPSSGCH	-	-	-	-	-	-	-	-
STMP	SG	STMPSG	(122,676,137)	(37,870,150)	(41,678,721)	(72,453,873)	(30,626,315)	118,200,856	(37,420,868)	(3,118,406)
STMP	NUTIL	STMPNUTIL	(9,037,852)	(9,000,747)	-	-	-	-	(3,607,720)	(300,643)
			<u>(203,878,565)</u>	<u>(55,380,895)</u>	<u>(49,830,757)</u>	<u>(103,673,042)</u>	<u>(35,485,512)</u>	<u>186,074,489</u>	<u>(52,434,856)</u>	<u>(4,369,571)</u>
HYDP	SG-U	HYDPSG-U	(69,704)	(208,532)	(669,210)	(688,887)	(596,216)	-	(446,510)	(37,209)
HYDP	SG-P	HYDPSG-P	(534,323)	(1,069,662)	(3,174,454)	(2,760,652)	(4,743,569)	1,277,015	(2,201,129)	(183,427)
HYDP	DGU	HYDPDGU	(35,672)	(187,001)	(523,331)	(406,073)	(819,933)	-	(394,402)	(32,867)
HYDP	DGP	HYDPDGP	(690,292)	(321,786)	(874,490)	(460,328)	(703,798)	43,446	(601,450)	(50,121)
HYDP	NUTIL	HYDPNUTIL	-	-	-	-	-	-	-	-
			<u>(1,329,991)</u>	<u>(1,786,981)</u>	<u>(5,241,484)</u>	<u>(4,315,941)</u>	<u>(6,863,517)</u>	<u>1,320,461</u>	<u>(3,643,490)</u>	<u>(303,624)</u>
OTHP	DGU	OTHPDGU	-	-	-	-	-	-	-	-
OTHP	SG	OTHPSG	(52,023,479)	(1,957,257)	(16,761,294)	(963,453)	(50,697,982)	-	(24,480,693)	(2,040,058)
OTHP	SG-W	OTHPSG-W	(6,963,155)	(4,776,936)	(82,725)	(844,072,708)	(412,145,767)	1,253,727,992	(2,862,660)	(238,555)
OTHP	SSGCT	OTHPSSGCT	(401,147)	(187,547)	(2,256,844)	73,283	-	-	(554,451)	(46,204)
OTHP	NUTIL	OTHPNUTIL	-	-	-	-	-	-	-	-
			<u>(59,387,781)</u>	<u>(6,921,740)</u>	<u>(19,100,863)</u>	<u>(844,962,878)</u>	<u>(462,843,749)</u>	<u>1,253,727,992</u>	<u>(27,897,804)</u>	<u>(2,324,817)</u>
TRNP	DGP	TRNPDGP	(1,393,287)	(2,977,569)	(1,293,599)	(2,194,511)	(2,231,965)	-	(2,018,186)	(168,182)
TRNP	DGU	TRNPDGU	(3,069,434)	(2,818,962)	(7,288,536)	(2,125,822)	(2,425,425)	-	(3,545,636)	(295,470)
TRNP	JBG	TRNPJBG	-	-	-	-	-	-	-	-
TRNP	SG	TRNPSG	(8,479,048)	(9,180,945)	(7,082,678)	(9,584,949)	(9,274,706)	-	(8,720,465)	(726,705)
TRNP	NUTIL	TRNPNUTIL	-	-	-	-	-	-	-	-
			<u>(12,941,768)</u>	<u>(14,977,477)</u>	<u>(15,664,813)</u>	<u>(13,905,283)</u>	<u>(13,932,096)</u>	<u>-</u>	<u>(14,284,287)</u>	<u>(1,190,357)</u>
DSTP	CA	DSTPCA	(767,723)	(691,930)	(4,729,076)	(1,367,157)	(1,186,564)	-	(1,748,490)	(145,707)
DSTP	ID	DSTPID	(1,625,059)	(1,736,718)	(2,203,340)	(1,930,395)	(1,813,227)	-	(1,861,748)	(155,146)
DSTP	MT	DSTPMT	-	-	-	-	-	-	-	-
DSTP	OR	DSTPOR	(7,879,266)	(9,930,730)	(42,097,594)	(33,806,510)	(12,101,471)	-	(21,163,114)	(1,763,593)
DSTP	UT	DSTPUT	(20,468,213)	(13,156,488)	(16,986,844)	(16,190,768)	(18,052,141)	-	(16,970,891)	(1,414,241)
DSTP	WA	DSTPWA	(1,866,808)	(1,797,818)	(2,504,228)	(3,224,732)	(2,535,929)	-	(2,385,903)	(198,825)
DSTP	WYU	DSTPWYU	(2,992,348)	(3,232,370)	(3,122,221)	(3,763,963)	(3,192,347)	-	(3,260,650)	(271,721)
DSTP	WYU	DSTPWYU	(374,558)	(241,028)	(296,106)	(325,291)	(430,096)	-	(333,416)	(27,785)
DSTP	NUTIL	DSTPNUTIL	-	-	-	-	-	-	-	-
			<u>(35,973,974)</u>	<u>(30,787,082)</u>	<u>(71,939,410)</u>	<u>(60,608,816)</u>	<u>(39,311,775)</u>	<u>-</u>	<u>(47,724,211)</u>	<u>(3,977,018)</u>
GNLP	SE	GNLPSE	(234,645)	(24,616)	(130,808)	(36,551)	(467,235)	-	(178,771)	(14,898)
GNLP	SSGCT	GNLPSSGCT	-	-	-	-	-	-	-	-
GNLP	SG	GNLPSSG	(7,978,440)	(5,884,655)	(5,290,627)	(4,624,892)	(10,925,287)	-	(6,940,780)	(578,398)
GNLP	DGP	GNLPDGP	(354,539)	(246,476)	(10,091)	(55,490)	(168,438)	-	(167,007)	(13,917)
GNLP	DGU	GNLPDGU	(414,250)	(1,280)	(70,539)	(115,871)	(1,244,766)	-	(369,341)	(30,778)
GNLP	SO	GNLPSO	(13,123,182)	(12,981,865)	(12,881,251)	(25,844,820)	(13,374,457)	-	(15,641,115)	(1,303,426)
GNLP	CN	GNLPCN	(1,021,984)	(598,547)	(3,163,468)	(384,219)	(797,489)	-	(1,193,141)	(99,428)
GNLP	CA	GNLPCA	(107,582)	(99,292)	(715,495)	(717,531)	(981,422)	-	(524,264)	(43,689)
GNLP	ID	GNLPID	(740,915)	(310,512)	(1,368,673)	(1,285,289)	(429,609)	-	(826,999)	(68,917)
GNLP	SSGCH	GNLPSSGCH	-	-	-	-	-	-	-	-
GNLP	OR	GNLPOR	(4,306,824)	(2,634,074)	(5,945,198)	(4,543,677)	(1,961,890)	-	(3,878,333)	(323,194)
GNLP	UT	GNLPUT	(4,549,271)	(3,346,788)	(7,770,797)	(4,139,974)	(8,951,496)	-	(5,751,665)	(479,305)
GNLP	WA	GNLPWA	(1,613,793)	(856,950)	(1,132,533)	(2,705,376)	(604,195)	-	(1,382,569)	(115,214)
GNLP	WYU	GNLPWYU	(510,756)	(319,125)	(493,517)	(343,869)	(235,183)	-	(380,490)	(31,708)
GNLP	WYP	GNLPWYP	(5,754,744)	(1,903,007)	(3,446,458)	(2,626,180)	(1,527,523)	-	(3,051,582)	(254,299)
GNLP	NUTIL	GNLPNUTIL	-	-	-	-	-	-	-	-
			<u>(40,710,925)</u>	<u>(29,207,187)</u>	<u>(42,419,454)</u>	<u>(47,423,739)</u>	<u>(41,668,990)</u>	<u>-</u>	<u>(40,286,059)</u>	<u>(3,357,172)</u>
MNGP	CAEE	MNGPCAEE	-	-	-	-	-	-	-	-
MNGP	NUTIL	MNGPNUTIL	-	-	-	-	-	-	-	-
			<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
INTP	JBG	INTPJBG	-	-	-	-	-	-	-	-
INTP	SG-P	INTPSG-P	-	-	-	(279,935)	-	-	(55,987)	(4,666)
INTP	SG-U	INTPSG-U	-	-	-	-	(895,226)	-	(179,045)	(14,920)
INTP	SG	INTPSG	(677,401)	(220,378)	(1,546,900)	(62,921)	(1,268,060)	-	(755,132)	(62,928)
INTP	SO	INTPSO	(42,906,524)	(4,298,237)	(5,104,327)	(8,329,898)	(6,745,772)	-	(13,476,952)	(1,123,079)
INTP	CN	INTPCN	(50,673)	(1,982,186)	(10,680)	(8,081)	-	-	(410,324)	(34,194)
INTP	SE	INTPSE	(221,464)	(8,646)	(14,653)	-	-	-	(48,953)	(4,079)
INTP	CA	INTPCA	-	-	-	-	-	-	-	-
INTP	ID	INTPID	-	(5,175)	-	-	-	-	(1,035)	(86)
INTP	OR	INTPOR	-	-	(21,797)	-	-	-	(4,359)	(363)
INTP	UT	INTPUT	-	(28,178)	-	-	(5,507)	-	(6,737)	(561)
INTP	WA	INTPWA	-	-	-	-	-	-	-	-
INTP	WYU	INTPWYU	-	-	-	-	-	-	-	-
INTP	WYP	INTPWYP	(463,713)	-	-	-	-	-	(92,743)	(7,729)
			<u>(44,319,775)</u>	<u>(6,542,800)</u>	<u>(6,698,358)</u>	<u>(8,680,835)</u>	<u>(8,914,565)</u>	<u>-</u>	<u>(15,031,267)</u>	<u>(1,252,606)</u>
			<u>(398,542,779)</u>	<u>(145,604,162)</u>	<u>(210,895,138)</u>	<u>(1,083,570,534)</u>	<u>(609,020,203)</u>	<u>1,441,122,943</u>	<u>(201,301,975)</u>	<u>(16,775,165)</u>

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**STEAM PLANT ADDITIONS:**

**U0 Huntington Water Redirect; U0 Land Application Conversion (Reference page 8.4.19) (in-Service Oct-21)**

Process water has historically been transported to the evaporation/holding pond for storage and then used as land application water as permitted by the original ground water permit. With the renewal of the ground water permit on April 1, 2018, this option was removed and the plant needed an alternative method for managing process water. This alternative method would instead route the water to either the Reverse Osmosis (RO) system for treatment or to the existing brine concentrator. During upset conditions more wastewater may be generated than the combination of the RO and brine concentrator can dispose of. At those times water will be sent to the evaporation/holding pond for storage. A level will be maintained in the evaporation pond that will maximize evaporation while maintaining adequate volume to allow draining of cooling towers if needed. When the level of the pond needs to be adjusted water will either be directed to the pond or returned to the plant for treatment and reuse.

**HYDRO PLANT ADDITIONS:**

**Merwin Downstream In-Lieu (Reference page 8.4.20) (in-service Dec-22)**

Per the 2004 Lewis River Settlement Agreement and incorporated by the Federal Energy Regulatory Commission licenses for the Merwin Hydroelectric project, the National Marine Fisheries Service and US Fish and Wildlife Service (“Services”) may elect that PacifiCorp mitigate project impacts to anadromous fish through aquatic habitat restoration projects in-lieu of constructing fish passage into and out of Merwin Reservoir. The Settlement Agreement identifies the amount of in-lieu funding to be spent upon the Services determination and is included in this project. Project also includes identification of habitat projects, consultation with settlement parties, permitting and construction of aquatic habitat projects that benefit anadromous fish.

**OTHER PLANT ADDITIONS:**

**TB Flats Wind Project 500 MW 2020 (Reference page 8.4.21) (in-service various)**

The TB Flats wind energy facility has a nominal capacity of 500 MW. The combined resource is located on a site approximately seven miles north, at its most southern boundary, of the town of Medicine Bow, in Carbon County, Wyoming. The project consists of 14 Vestas model V110-2.0 MW-80 hub height and 51 Vestas model V136-4.3 MW-82 WTGs for TB Flats I, and an additional 14 Vestas model V110-2.0 MW-80 and 53 Vestas model V136-4.3 MW-82 WTGs for TB Flats II; 34.5 kilovolt (“kV”) underground collector systems; a TB Flats I collector substation; a TB Flats II collector substation; an approximately 11-mile long 230 kV transmission tie-line from the south area TB II collector substation to the north area TB I collector substation; an O&M building; approximately 40 miles of WTG site access roads; meteorological evaluation towers; a SCADA control system; and approximately 500 feet of 230 kV short span transmission tie-line interconnecting the project from the TB I collector substation to the existing Shirley Basin substation at 230 kV. The in-service dates for the project were December 2020 through July 2021.

**Currant Creek U1 CSA Variable Fee - CTA MI (Reference page 8.4.21) (in-service Oct-21)**

This project is required to maintain reliability of combustion turbine No. 1A. Without this work, the unit will be susceptible to failure of certain components resulting in a forced outage and subsequent loss of generation. The Currant Creek Plant amended its Contractual Services Agreement (CSA) with General Electric (GE) on January 15, 2016. This agreement requires the company to pay a factored fired hour (FFH) fee to GE for each hour the combustion turbine operates. In return for the quarterly FFH payments, GE provides all combustion parts and services in accordance with the CSA agreement. In accordance with the CSA, this major inspection overhaul is to be conducted when the combustion turbine has operated for approximately 32,000 hours or 1200 starts, whichever occurs first. This major inspection is scheduled to commence in 2021 based on operating hours.

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**Currant Creek U2 CSA Variable Fee - CTB MI (Reference page 8.4.21) (in-service Oct-21)** This project is required to maintain reliability of combustion turbine No. 1B. Without this work, the unit will be susceptible to failure of certain components resulting in a forced outage and subsequent loss of generation. The Currant Creek Plant amended its Contractual Services Agreement (CSA) with General Electric (GE) on January 15, 2016. This agreement requires the company to pay a factored fired hour (FFH) fee to GE for each hour the combustion turbine operates. In return for the quarterly FFH payments, GE provides all combustion parts and services in accordance with the CSA agreement. In accordance with the CSA, this major inspection overhaul is to be conducted when the combustion turbine has operated for approximately 32,000 hours or 1200 starts, whichever occurs first. This major inspection is scheduled to commence in 2021 based on operating hours.

**Chehalis U1 CSA Variable fee - CT1 - HGP (Reference page 8.4.21) (in-Service Apr-22)**

This project is required to maintain reliability of combustion turbine 1. Without this work, the unit will be susceptible to failure of certain components resulting in a forced outage and subsequent loss of generation. The Chehalis Plant amended its Contractual Services Agreement (CSA) with General Electric (GE) on January 15, 2016. This agreement requires the company to pay a factored fired hour (FFH) fee to GE for each hour the combustion turbine operates. In return for the quarterly FFH payments, GE provides all combustion parts and services in accordance with the CSA agreement. In accordance with the CSA, this major inspection overhaul is to be conducted when the combustion turbine has operated for approximately 32,000 hours or 1200 starts, whichever occurs first.

**Chehalis U2 CSA Variable fee - CT2 - HGP (Reference page 8.4.21) (in-service Apr-22)**

This project is required to maintain reliability of combustion turbine 2. Without this work, the unit will be susceptible to failure of certain components resulting in a forced outage and subsequent loss of generation. The Chehalis Plant amended its Contractual Services Agreement (CSA) with General Electric (GE) on January 15, 2016. This agreement requires the company to pay a factored fired hour (FFH) fee to GE for each hour the combustion turbine operates. In return for the quarterly FFH payments, GE provides all combustion parts and services in accordance with the CSA agreement. In accordance with the CSA, this major inspection overhaul is to be conducted when the combustion turbine has operated for approximately 32,000 hours or 1200 starts, whichever occurs first.

**Pryor Mtn Wind Project 240 MW 2020 (Reference page 8.4.21) (in-service various)**

The Pryor Mountain wind project will have a nominal rated capacity of 240 MW. The resource will be located on a site in Carbon County, Montana, approximately sixty miles south of Billings, Montana. The project consists of 110 Vestas Model 110-2.0/2.2 MW wind turbines and four General Electric Model 116-2.3 MW wind turbines. In addition to the 114 wind turbines there will be a 34.5 kilovolt ("kV") collector system; a collector substation with two 34.5 kV to 230 kV step-up transformers, an O&M building and site access roads. Under a separate APR, PacifiCorp, as the transmission provider, will construct a new point of interconnection substation located on the project site in Montana. The in-service dates for the project were December 2020 through March 2021, and the entire project was declared in Commercial Operation April 1, 2021.

**TRANSMISSION PLANT ADDITIONS:**

**Goshen-Sugarmill-Rigby 161kV Transmission Line (Reference 8.4.22) (in-service Jan-22)**

This project addresses overloading on the Goshen to Rigby and Goshen to Sugarmill lines in Idaho by converting the lines from 69kV to 161kV. The line from Goshen Substation to Sugarmill substation was completed in 2020 and 2021. The line from Sugarmill to Rigby will be completed in 2022. This includes a 12-miles of new 161kV shared transmission line with Idaho Falls power.

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**Jordanelle - Midway Construct 138 kV Line – Trans (Reference 8.4.22) (in-service Dec-21)**

This project will:

- Construct 9 miles of 138 kilovolt transmission line between the Midway and Jordanelle substations
- Add a three 138 kilovolt breaker ring bus at the Midway substation
- Add fiber optic communications between the Silver Creek and Midway substations
- Install protection and control upgrades at all affected substations

The line siting will substantively follow Heber Light and Power's (HLP) existing 46 kilovolt line across the Heber Valley. The structures will be owned by Rocky Mountain Power (RMP) and, for portions, HLP will have circuits and other facilities attached to RMP structures. After project completion, the Summit and Wasatch County system will be capable of operating in a looped configuration for area load levels up to 245 megawatts.

**Klamath Falls - Snow Goose 230 kV Line No. 2 TPL (Reference 8.4.22) (in-service Nov-22)**

This project builds a second 230 kV transmission line from Snow Goose to Klamath Falls substation located in Klamath County, Oregon.

The overall project is needed to maintain compliance with the North American Electric Reliability Corporation (NERC) Reliability Standard TPL-001-4 and Western Electricity Coordinating Council (WECC) Criterion TPL-001-WECC-CRT-3.1 for double contingencies on the 230 kV system serving Yreka, Klamath Falls and La Pine area. The TPL-001-4 category P6 (N-1-1) contingency for the loss of the Klamath Falls-Snow Goose 230 kV line and either the Lone Pine-Copco 230 kV line or Bonneville Power Administration's (BPA) Pilot Butte-La Pine 230 kV line can cause a voltage collapse affecting a large region of the southern Oregon and northern California system. The proposed transmission line will mitigate risks on the existing system by reinforcing the area 230 kV system with a new source from Snow Goose.

**Rexburg Sub - Inst 161kV Source from Rigby (Reference 8.4.22) (in-service Nov-21)**

This project will convert an existing 69 kV line to 161 kV operation, increase capacity on Rexburg transformer #2 and regulators, and establish a new 161 kV source at Rexburg substation.

This overall project addresses overloading on the Rexburg transformer #2 regulators and low voltage on the 69 kV Rigby-St. Anthony and Rigby-Webster loop. It also addresses N-1 overloading on the Rigby 161-69 kV transformers and 69 kV line capacity north of Rigby.

**Pacific Power Transmission Wildfire Mitigation Projects (Reference 8.4.22) (in-service various)**

Projects will include:

- Rebuild transmission lines that are approaching the end of their useful life in Fire High Consequence Areas to new wildfire safe designs
- Modify existing transmission lines to new wildfire safe designs
- Replace outdated electromechanical relays protecting transmission lines in Fire High Consequence Areas with modern microprocessor relays that provide more accurate data that is required in Fire High Consequence Areas
- Add fiber optic communication between substations in the Fire High Consequence Areas to improve protective relaying schemes

These projects will result in decreased risk of transmission equipment failure during the wildfire season, which is increasing in length every year. Modern relaying will enable line patrols to quickly locate and fix any problems, restoring service to customers faster. Fiber optic communications between substations in Fire High Concern Areas will improve the clearing times for protective relaying schemes, which will reduce the time the fault is active. New wildfire safe designs on the transmission system will improve the survivability of the lines in the event that a wildfire does occur.



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**Rocky Mountain Power Transmission Wildfire Mitigation (Reference 8.4.22) (in-service various)**

Projects will include:

- Rebuild transmission lines that are approaching the end of their useful life in Fire High Consequence Areas to new wildfire safe designs
- Modify existing transmission lines to new wildfire safe designs
- Replace outdated electromechanical relays protecting transmission lines in Fire High Consequence Areas with modern microprocessor relays that provide more accurate data that is required in Fire High Consequence Areas
- Add fiber optic communication between substations in the Fire High Consequence Areas to improve protective relaying schemes

These projects will result in decreased risk of transmission equipment failure during the wildfire season, which is increasing in length every year. Modern relaying will enable line patrols to quickly locate and fix any problems, restoring service to customers faster. Fiber optic communications between substations in Fire High Concern Areas will improve the clearing times for protective relaying schemes, which will reduce the time the fault is active. New wildfire safe designs on the transmission system will improve the survivability of the lines in the event that a wildfire does occur.

**Jim Bridger 345-230 kV Transformer 2 Upgrade (Reference 8.4.22) (PP) (in-service Oct-21)**

This project replaces the existing Jim Bridger 345/230 kV transformer #2 (200 MVA) with a new 700 MVA transformer resolving thermal overload issues on the existing transformer and maintains compliance with North American Electric Reliability Corporation (NERC) Reliability Standard TPL-001-4 Category P1 and P3.

**DISTRIBUTION PLANT ADDITIONS:**

**Wildfire - Dist – OR (Reference 8.4.23) (in-service various)**

This project outlines the preventative strategies and programs PacifiCorp will implement to its electric distribution and transmission infrastructure that will minimize the risk that causes wildfires. Due to the growing threat of wildfire in the western United States, PacifiCorp has developed a comprehensive wildfire mitigation plan. This plan will guide PacifiCorp's efforts to minimize the chances of a fire igniting from any of PacifiCorp's facilities. This project details PacifiCorp's planned efforts to construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire

**GENERAL PLANT ADDITIONS:**

**AMI - IT Comm Network (Reference page 8.4.25) (in-service Dec-22)**

This project will update and configure the head-end AMI software and upgrade the company's current Energy Usage Website while maintaining integration with legacy computer systems. This upgrade will provide additional capacity to allow for future customer growth across all states. The head-end enables the utility to use the data captured by the smart meter to provide accurate customer bills, interval consumption data to customers and send remote commands such as connect or disconnect to the smart meter.

**Lloyd Center Tower Open Office (Reference page 8.4.25) (in-service various)**

This project provides for the remodeling of the Lloyd Center Tower (LCT) building in Portland, Oregon, to a concept that allows for greater employee engagement. The remodel is expected to create a sustainable competitive advantage ultimately benefitting customers through higher employee retention and recruitment, enhanced productivity, and greater operational performance. Assets will include architectural services, construction of conference rooms and enclaves. It includes the installation of power/data/phone wiring, flooring, furniture, appliances, and finishes on the floors. Construct and furnish two common breakrooms: one breakroom on floor 6 and another on floor 18. Project will be completed

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by the end of 2022.

**INTANGIBLE PLANT ADDITIONS:**

**Maximo Phase 1A (Reference page 8.4.26) (in-Service Jun-22)**

Maximo is a world-class enterprise asset management software. With an average system age of 17 years, 80 percent of the core asset and work management systems at the BHE companies are beyond end-of-life. Modernizing enterprise asset management capabilities will lower or eliminate the costs and complexities associated with outdated systems. System integration will allow us to better serve our customers while adhering to compliance timelines through reduced costs, increased security and simplified processes across the business. Implementing a standardized tool for asset and work management across BHE will enable standardized processes, universal visibility and master data integrity – including data driven reporting, analysis and decision making – positioning us to be a more agile organization, improve the employee experience and better serve our customers. Maximo Phase 1A rollout for PacifiCorp is scheduled for in-service in Q2 2022 and will focus on substation operations, including preventative maintenance scheduling and field inspection results collection.

**PacifiCorp**  
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**Customer Advances for Construction**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Customer Advances	252	1	(116,018)	CA	Situs	-	8.5.1
Customer Advances	252	1	(645,790)	OR	Situs	(645,790)	8.5.1
Customer Advances	252	1	(683,516)	WA	Situs	-	8.5.1
Customer Advances	252	1	(1,345,561)	ID	Situs	-	8.5.1
Customer Advances	252	1	(17,097,144)	UT	Situs	-	8.5.1
Customer Advances	252	1	(2,110,851)	WYP	Situs	-	8.5.1
Customer Advances	252	1	21,998,879	SG	26.070%	5,735,183	8.5.1
			-			5,089,393	

**Description of Adjustment:**

Customer advances for construction are booked into FERC account 252 and do not reflect the proper allocation factor. This adjustment corrects the allocation of customer advances for construction.

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**Customer Advances for Construction**

**END OF PERIOD BASIS:**

<b>Account</b>	<b>Booked Allocation</b>	<b>Correct Allocation</b>	<b>Adjustment</b>	<b>Ref.</b>
252CA	-	(116,018)	<b>(116,018)</b>	<b>Page 8.5</b>
252OR	(1,424,117)	(2,069,907)	<b>(645,790)</b>	<b>Page 8.5</b>
252WA	-	(683,516)	<b>(683,516)</b>	<b>Page 8.5</b>
252IDU	-	(1,345,561)	<b>(1,345,561)</b>	<b>Page 8.5</b>
252UT	(115,759)	(17,212,903)	<b>(17,097,144)</b>	<b>Page 8.5</b>
252WYP	-	(2,110,851)	<b>(2,110,851)</b>	<b>Page 8.5</b>
252SG	(30,469,074)	(8,470,195)	<b>21,998,879</b>	<b>Page 8.5</b>
<b>Total</b>	<b>(32,008,950)</b>	<b>(32,008,950)</b>	<b>-</b>	

**PacifiCorp**  
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**Regulatory Assets & Liabilities Amortization**

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Note: Please see Confidential Exhibit PAC/1008 for redacted information.

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Revenues:</b>							
Pryor Mountain REC Sales	456	3	[REDACTED]	OR	Situs	[REDACTED]	8.6.6_CONF
FERC OATT Deferral Refund	456	3	[REDACTED]	OR	Situs	[REDACTED]	8.6.7_CONF
<b>Adjustment to Expense:</b>							
Elec. Plant Acq. Amort. Exp.	406	3	(4,706,208)	SG	26.070%	(1,226,925)	8.6.1
TE Pilot Deferral Amort.	407	3	974,165	OR	Situs	974,165	8.6.4
Oregon Depreciation Decrease Deferral	407	3	(2,828,006)	OR	Situs	(2,828,006)	8.6.9
<b>Adjustment to Rate Base:</b>							
Elec. Plant Gross Acq.	114	3	(141,186,243)	SG	26.070%	(36,807,736)	8.6.1
Elec. Plant Acq. Acc. Amort.	115	3	137,153,218	SG	26.070%	35,756,313	8.6.1
<b>Adjustment to Tax:</b>							
Schedule M Adjustment	SCHMAT	3	974,165	OR	Situs	974,165	8.6.4
Deferred Income Tax Expense	41110	3	(239,520)	OR	Situs	(239,520)	8.6.4
Schedule M Adjustment	SCHMDT	3	[REDACTED]	OR	Situs	[REDACTED]	8.6.5_CONF
Deferred Income Tax Expense	41010	3	[REDACTED]	OR	Situs	[REDACTED]	8.6.5_CONF
Schedule M Adjustment	SCHMAT	3	[REDACTED]	OR	Situs	[REDACTED]	8.6.7_CONF
Deferred Income Tax Expense	41010	3	[REDACTED]	OR	Situs	[REDACTED]	8.6.7_CONF
Schedule M Adjustment	SCHMDT	3	2,828,006	OR	Situs	2,828,006	8.6.9
Deferred Income Tax Expense	41110	3	695,313	OR	Situs	695,313	8.6.9

**Description of Adjustment:**

This adjustment adds into results the proposed amortization of deferred expenses from the Transportation Electrification Pilot deferral (Docket UM 1964), and the deferral of Oregon's Share of Pryor Mountain REC Revenues in 2021 and 2022. This adjustment also adds into Oregon results the 2023 level of annual revenues expected from the sales of REC from Pryor Mountain.

In addition, this adjustment walks forward the amortization of the remainder of the Post-2017 FERC OATT Revenue Deferral balance, net of the net book value of replaced wind equipment, as well as the continued amortization of the Oregon Depreciation Decrease deferral that were approved in the Company's last general rate case, Docket No. UE 374.

Finally, this adjustment also walks forward Electric Plant Acquisition in the base period (12 months ended June 2021) to pro forma period levels (12 months ending December 2023).

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**Regulatory Assets & Liabilities Amortization**  
**Electric Plant Acquisition Adjustment**

**Adjust Base Period to Pro Forma Period**

	<u>Amortization</u>	<u>Rate Base</u>	
		<u>Gross Acq.</u>	<u>Acc Amort</u>
Pro Forma Amount (below)	75,351	3,518,456	(827,259)
Base Period Amount (below)	4,781,559	144,704,699	(137,980,477)
<b>Pro Forma Adjustment</b>	<b>(4,706,208)</b>	<b>(141,186,243)</b>	<b>137,153,218</b>
	<b>Ref. 8.6</b>	<b>Ref. 8.6</b>	<b>Ref. 8.6</b>

Year	<u>Gross Acquisition</u>	<u>Rate Base</u>		<u>End Balance Accumulated Amortization</u>	<u>13 Month Avg Bal</u>	
		<u>Beg Balance Accumulated Amortization</u>	<u>Amortization</u>		<u>Gross Acq</u>	<u>Acc Amort</u>
Opening Balance	144,704,699			(133,198,918)		
2020 July	144,704,699	(133,198,918)	(398,463)	(133,597,381)		
August	144,704,699	(133,597,381)	(398,463)	(133,995,844)		
September	144,704,699	(133,995,844)	(398,463)	(134,394,308)		
October	144,704,699	(134,394,308)	(398,463)	(134,792,771)		
November	144,704,699	(134,792,771)	(398,463)	(135,191,234)		
December	144,704,699	(135,191,234)	(398,463)	(135,589,698)		
2021 January	144,704,699	(135,589,698)	(398,463)	(135,988,161)		
February	144,704,699	(135,988,161)	(398,463)	(136,386,624)		
March	144,704,699	(136,386,624)	(398,463)	(136,785,087)		
April	144,704,699	(136,785,087)	(398,463)	(137,183,551)		
May	144,704,699	(137,183,551)	(398,463)	(137,582,014)		
June	144,704,699	(137,582,014)	(398,463)	(137,980,477)	144,704,699	(135,589,698)
		<b>Base Period Amort =</b>	<b>(4,781,559)</b>			
2021 July	144,704,699	(137,980,477)	(398,463)	(138,378,940)		
August	144,704,699	(138,378,940)	(398,463)	(138,777,404)		
September	144,704,699	(138,777,404)	(398,463)	(139,175,867)		
October	144,704,699	(139,175,867)	(398,463)	(139,574,330)		
November	144,704,699	(139,574,330)	(398,463)	(139,972,794)		
December	144,704,699	(139,972,794)	(398,463)	(140,371,257)		
2022 January	144,704,699	(140,371,257)	(398,463)	(140,769,720)		
February	144,704,699	(140,769,720)	(398,463)	(141,168,183)		
March	144,704,699	(141,168,183)	(398,463)	(141,566,647)		
April	144,704,699	(141,566,647)	(358,945)	(141,925,591)		
May	3,518,456	(739,349)	(6,279)	(745,628)		
June	3,518,456	(745,628)	(6,279)	(751,907)		
July	3,518,456	(751,907)	(6,279)	(758,187)		
August	3,518,456	(758,187)	(6,279)	(764,466)		
September	3,518,456	(764,466)	(6,279)	(770,745)		
October	3,518,456	(770,745)	(6,279)	(777,024)		
November	3,518,456	(777,024)	(6,279)	(783,304)		
December	3,518,456	(783,304)	(6,279)	(789,583)		
2023 January	3,518,456	(789,583)	(6,279)	(795,862)		
February	3,518,456	(795,862)	(6,279)	(802,142)		
March	3,518,456	(802,142)	(6,279)	(808,421)		
April	3,518,456	(808,421)	(6,279)	(814,700)		
May	3,518,456	(814,700)	(6,279)	(820,979)		
June	3,518,456	(820,979)	(6,279)	(827,259)		
July	3,518,456	(827,259)	(6,279)	(833,538)		
August	3,518,456	(833,538)	(6,279)	(839,817)		
September	3,518,456	(839,817)	(6,279)	(846,097)		
October	3,518,456	(846,097)	(6,279)	(852,376)		
November	3,518,456	(852,376)	(6,279)	(858,655)		
December	3,518,456	(858,655)	(6,279)	(864,934)	3,518,456	(827,259)
		<b>Pro Forma Amort =</b>	<b>(75,351)</b>			

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Regulatory Assets & Liabilities Amortization**  
**Electric Plant Acquisition Adjustment**  
**GL Account 140800 - Actuals for 12 Months Ended June 2021**

Year	Month	Addition / Amortization	Accumulated Amount
2020	6	-	156,468,483
2020	7	-	156,468,483
2020	8	-	156,468,483
2020	9	-	156,468,483
2020	10	-	156,468,483
2020	11	-	156,468,483
2020	12	-	156,468,483
2021	1	-	156,468,483
2021	2	-	156,468,483
2021	3	-	156,468,483
2021	4	-	156,468,483
2021	5	-	156,468,483
2021	6	-	<b>156,468,483</b>

System-allocated amount	144,704,699	<b>Ref Tab B-15 &amp; 8.6.1</b>
Utah-situs amount	11,763,784	<b>Ref Tab B-15</b>
	<b>156,468,483</b>	

**GL Account Balance**  
**Account Number 140800**  
**Calendar year 2020**

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 2021**

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

PacifiCorp  
Oregon General Rate Case - December 2023  
Regulatory Assets & Liabilities Amortization  
Accumulated Amortization  
GL Account 145800 - Actuals for 12 Months Ended June 2021

Year	Month	Amort.	Accumulated Amount
2018	6	(423,600)	(134,794,824)
2018	7	(423,600)	(135,218,423)
2018	8	(423,600)	(135,642,023)
2018	9	(423,600)	(136,065,622)
2018	10	(423,600)	(136,489,222)
2018	11	(423,600)	(136,912,822)
2018	12	(423,600)	(137,336,421)
2019	1	(423,600)	(137,760,021)
2019	2	(423,600)	(138,183,620)
2019	3	(423,600)	(138,607,220)
2019	4	(423,600)	(139,030,819)
2019	5	(423,600)	(139,454,419)
2019	6	(423,600)	<b>(139,878,019)</b>

System-allocated amount (137,980,477) Ref. Tab B-15 & 8.6.1  
Utah-situs amount (1,897,541) Ref. Tab B-15  
**(139,878,019)**

GL Account Balance  
Account Number 145800  
Calendar year 2020

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				132,253,226.26-
1		423,599.57	423,599.57-	132,676,825.83-
2		423,599.58	423,599.58-	133,100,425.41-
3		423,599.57	423,599.57-	133,524,024.98-
4		423,599.59	423,599.59-	133,947,624.57-
5		423,599.56	423,599.56-	134,371,224.13-
6		423,599.58	423,599.58-	134,794,823.71-
7		423,599.58	423,599.58-	135,218,423.29-
8		423,599.56	423,599.56-	135,642,022.85-
9		423,599.58	423,599.58-	136,065,622.43-
10		423,599.58	423,599.58-	136,489,222.01-
11		423,599.58	423,599.58-	136,912,821.59-
12		423,599.57	423,599.57-	137,336,421.16-

Calendar year 2021

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				137,336,421.16-
1		423,599.57	423,599.57-	137,760,020.73-
2		423,599.58	423,599.58-	138,183,620.31-
3		423,599.57	423,599.57-	138,607,219.88-
4		423,599.59	423,599.59-	139,030,819.47-
5		423,599.56	423,599.56-	139,454,419.03-
6		423,599.58	423,599.58-	139,878,018.61-
7		423,599.58	423,599.58-	140,301,618.19-
8		423,599.56	423,599.56-	140,725,217.75-
9		423,599.58	423,599.58-	141,148,817.33-
10		423,599.58	423,599.58-	141,572,416.91-
11		423,599.58	423,599.58-	141,996,016.49-
12				141,996,016.49-



**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Regulatory Assets & Liabilities Amortization**  
**Oregon Transportation Electrification Pilot Programs**

**Amortization**

Base Period Amount (below)	-
Pro Forma Amount (below)	974,165
Adjustment:	<u>974,165</u>
	<b>Ref. 8.6</b>

	Opening Bal.	Accrual <sup>1</sup>	Amortization	Interest <sup>2</sup>	Ending Bal.		
2021 June	2,173,972	37,436	-	13,041	2,224,449		
July	2,224,449	11,430	-	13,264	2,249,143		
August	2,249,143	49,244	-	13,524	2,311,911		
September	2,311,911	136,742	-	14,157	2,462,810		
October	2,462,810	24,868	-	14,722	2,502,400		
November	2,502,400	56,269	-	15,051	2,573,720		
December	2,573,720	55,633	-	15,473	2,644,827		
2022 January	2,644,827	-	-	15,731	2,660,557		
February	2,660,557	-	-	15,824	2,676,381		
March	2,676,381	-	-	15,918	2,692,300		
April	2,692,300	-	-	16,013	2,708,312		
May	2,708,312	-	-	16,108	2,724,421		
June	2,724,421	-	-	16,204	2,740,625		
July	2,740,625	-	-	16,300	2,756,925		
August	2,756,925	-	-	16,397	2,773,322		
September	2,773,322	-	-	16,495	2,789,817		
October	2,789,817	-	-	16,593	2,806,410		
November	2,806,410	-	-	16,692	2,823,101	<b>SCHMDT</b>	<b>41010</b>
December	2,823,101	-	-	16,791	2,839,892	-	-
2023 January	2,839,892	-	81,180	4,369	2,763,081	81,180	(19,960)
February	2,763,081	-	81,180	4,252	2,686,152	81,180	(19,960)
March	2,686,152	-	81,180	4,136	2,609,108	81,180	(19,960)
April	2,609,108	-	81,180	4,019	2,531,946	81,180	(19,960)
May	2,531,946	-	81,180	3,902	2,454,667	81,180	(19,960)
June	2,454,667	-	81,180	3,784	2,377,271	81,180	(19,960)
July	2,377,271	-	81,180	3,667	2,299,758	81,180	(19,960)
August	2,299,758	-	81,180	3,550	2,222,127	81,180	(19,960)
September	2,222,127	-	81,180	3,432	2,144,378	81,180	(19,960)
October	2,144,378	-	81,180	3,314	2,066,512	81,180	(19,960)
November	2,066,512	-	81,180	3,196	1,988,527	81,180	(19,960)
December	1,988,527	-	81,180	3,077	1,910,424	81,180	(19,960)
	<b>Pro Forma Amort =</b>		<b>974,165</b>			<b>974,165</b>	<b>(239,520)</b>
						<b>Ref 8.6</b>	<b>Ref 8.6</b>

Note:

- Reflects accrued amounts through December 2021. Starting 1/1/2022, TE Pilot costs are expected to be recovered through the System Benefits Charge.
- Interest accrual at authorized rate of return during deferral period, and at current Modified Blended Treasury rate during amortization period.

	pre 2021	2021
Auth. ROR	7.621%	7.137%
	Ref UE-263	Ref UE-374
	2022	
MBTR	1.820%	
	Ref UM-1147	

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Regulatory Assets & Liabilities Amortization**  
**Pryor Mountain REC Sales Revenue Deferral**

Note: Please see Confidential Exhibit PAC/1008 for redacted information.

	<u><b>Amortization</b></u>
Base Period Amount (below)	-
Pro Forma Amount (below)	[REDACTED]
Adjustment:	[REDACTED]
	<b>Ref. 8.6</b>

	Opening Bal.	Accrual <sup>1</sup>	Amortization	Interest <sup>2</sup>	Ending Bal.
2021 June	-	-	-	-	-
July	[REDACTED]	-	-	[REDACTED]	[REDACTED]
August	[REDACTED]	-	-	[REDACTED]	[REDACTED]
September	[REDACTED]	-	-	[REDACTED]	[REDACTED]
October	[REDACTED]	-	-	[REDACTED]	[REDACTED]
November	[REDACTED]	-	-	[REDACTED]	[REDACTED]
December	[REDACTED]	-	-	[REDACTED]	[REDACTED]
2022 January	[REDACTED]	-	-	[REDACTED]	[REDACTED]
February	[REDACTED]	-	-	[REDACTED]	[REDACTED]
March	[REDACTED]	-	-	[REDACTED]	[REDACTED]
April	[REDACTED]	-	-	[REDACTED]	[REDACTED]
May	[REDACTED]	-	-	[REDACTED]	[REDACTED]
June	[REDACTED]	-	-	[REDACTED]	[REDACTED]
July	[REDACTED]	-	-	[REDACTED]	[REDACTED]
August	[REDACTED]	-	-	[REDACTED]	[REDACTED]
September	[REDACTED]	-	-	[REDACTED]	[REDACTED]
October	[REDACTED]	-	-	[REDACTED]	[REDACTED]
November	[REDACTED]	-	-	[REDACTED]	[REDACTED]
December	[REDACTED]	-	-	[REDACTED]	[REDACTED]
				SCHMDT	41010
				-	-
2023 January	[REDACTED]	-	[REDACTED]	[REDACTED]	[REDACTED]
February	[REDACTED]	-	[REDACTED]	[REDACTED]	[REDACTED]
March	[REDACTED]	-	[REDACTED]	[REDACTED]	[REDACTED]
April	[REDACTED]	-	[REDACTED]	[REDACTED]	[REDACTED]
May	[REDACTED]	-	[REDACTED]	[REDACTED]	[REDACTED]
June	[REDACTED]	-	[REDACTED]	[REDACTED]	[REDACTED]
July	[REDACTED]	-	[REDACTED]	[REDACTED]	[REDACTED]
August	[REDACTED]	-	[REDACTED]	[REDACTED]	[REDACTED]
September	[REDACTED]	-	[REDACTED]	[REDACTED]	[REDACTED]
October	[REDACTED]	-	[REDACTED]	[REDACTED]	[REDACTED]
November	[REDACTED]	-	[REDACTED]	[REDACTED]	[REDACTED]
December	[REDACTED]	-	[REDACTED]	[REDACTED]	[REDACTED]
	<b>Pro Forma Amort =</b>				
				<b>Ref 8.6</b>	<b>Ref 8.6</b>

Note:

1. Reflects accrued amounts through December 2022. Starting 1/1/2023, the Company is proposing including Oregon's share of forecasted Pryor Mountain REC Revenues in base rates.
2. Interest accrual at authorized rate of return during deferral period, and at current Modified Blended Treasury rate during amortization period.

	2021	
Auth. ROR	7.137%	Ref UE-374
	2022	
MBTR	1.820%	Ref UM-1147

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Regulatory Assets & Liabilities Amortization**  
**Pryor Mountain REC Sales Revenue Forecast**

*Note: Please see Confidential Exhibit PAC/1008 for redacted information.*

	Total Company			SG	OR Alloc.
	Quantity	Rate	Revenue	Factor	Revenue
Jan-23					
Feb-23					
Mar-23					
Apr-23					
May-23					
Jun-23					
Jul-23					
Aug-23					
Sep-23					
Oct-23					
Nov-23					
Dec-23					

Pryor Mountain REC Revenues Amort		Ref 8.6.5
Pryor Mountain REC Revenues Forecast		Above
Tota Pryor Mountain REC Revenues Adjustment		<b>Ref 8.6</b>

PacifiCorp  
Oregon General Rate Case - December 2023  
Regulatory Assets & Liabilities Amortization  
FERC OATT Revenues Deferral (Post 2017)

Amortization  
Base Period Amount (below) [Redacted]  
Pro Forma Amount (below) [Redacted]  
Adjustment: [Redacted]  
Ref. 8.6

Note: Please see Confidential Exhibit PAC/1008 for redacted information.

	Opening Bal.	Accrual	Adjustment	Amortization	Interest <sup>1,2</sup>	Ending Bal.
2020 June	[Redacted]					
July	[Redacted]					
August	[Redacted]					
September	[Redacted]					
October	[Redacted]					
November	[Redacted]					
December	[Redacted]					
2021 January	[Redacted]					
February	[Redacted]					
March	[Redacted]					
April	[Redacted]					
May	[Redacted]					
June	[Redacted]					
	Base Period Amort =			[Redacted]		

2021 July	[Redacted]					
August	[Redacted]					
September	[Redacted]					
October	[Redacted]					
November	[Redacted]					
December	[Redacted]					
2022 January	[Redacted]					
February	[Redacted]					
March	[Redacted]					
April	[Redacted]					
May	[Redacted]					
June	[Redacted]					
July	[Redacted]					
August	[Redacted]					
September	[Redacted]					
October	[Redacted]					
November	[Redacted]					
December	[Redacted]					
2023 January	[Redacted]					
February	[Redacted]					
March	[Redacted]					
April	[Redacted]					
May	[Redacted]					
June	[Redacted]					
July	[Redacted]					
August	[Redacted]					
September	[Redacted]					
October	[Redacted]					
November	[Redacted]					
December	[Redacted]					
	Pro Forma Amort =			4,075,388		

SCHMDT	41010
[Redacted]	
Ref 8.6	Ref 8.6

Note:

- Interest rate in deferral period per approved WACC from UE-263.
- Interest accrual at Modified Blended Treasury Rate as of date of the Commission's approval of the amortization (i.e. Dec 2020)

	2020	
MBTR	2.630%	Ref UM-1147

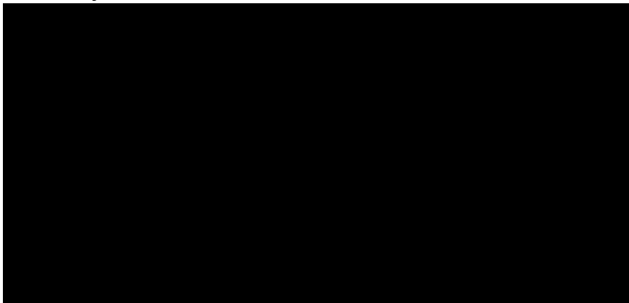
PacifiCorp  
Oregon General Rate Case - December 2023  
Regulatory Assets & Liabilities Amortization  
FERC OATT Revenues Deferral (Post 2017)  
GL Account 288232 - Actuals for 12 Months Ended June 2021

*Note: Please see Confidential Exhibit PAC/1008 for redacted information.*

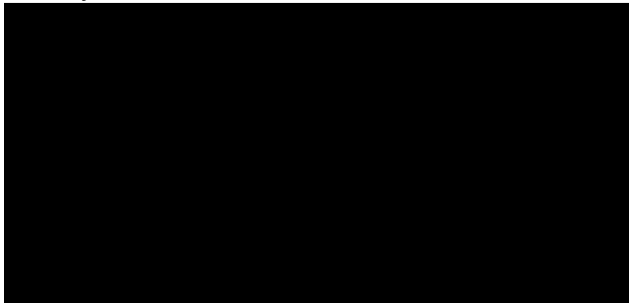
Year	Month	Accrual	Adjust.	Amort.	Interest	Accumulated Amount
2020	6					
2020	7					
2020	8					
2020	9					
2020	10					
2020	11					
2020	12					
2021	1					
2021	2					
2021	3					
2021	4					
2021	5					
2021	6					

Ref 8.6.7

GL Account Balance  
Account Number 288232  
Calendar year 2020



Calendar year 2021



PacifiCorp  
Oregon General Rate Case - December 2023  
Regulatory Assets & Liabilities Amortization  
Oregon Depreciation Decrease Deferral

Pro Forma Amount (below) **Amortization**  
**2,828,006**  
**Ref. 8.6**

	Opening Bal.	Accrual	Amortization	Interest <sup>1,2</sup>	Ending Bal.		
2020 June	(7,101,371)	(71,566)	-	(45,327)	(7,218,264)		
July	(7,218,264)	(71,566)	-	(46,069)	(7,335,899)		
August	(7,335,899)	(71,566)	-	(46,816)	(7,454,281)		
September	(7,454,281)	(71,566)	-	(47,568)	(7,573,415)		
October	(7,573,415)	(71,566)	-	(48,325)	(7,693,306)		
November	(7,693,306)	(71,566)	-	(49,086)	(7,813,958)		
December	(7,813,958)	(71,566)	-	(49,852)	(7,935,376)		
2021 January	(7,935,376)	-	220,427	(8,086)	(7,723,035)		
February	(7,723,035)	-	220,658	(7,866)	(7,510,243)		
March	(7,510,243)	-	220,890	(7,646)	(7,297,000)		
April	(7,297,000)	-	221,121	(7,426)	(7,083,305)		
May	(7,083,305)	-	221,353	(7,205)	(6,869,157)		
June	(6,869,157)	-	221,586	(6,984)	(6,654,555)	Ref 8.6.10	
July	(6,654,555)	-	221,818	(6,762)	(6,439,498)		
August	(6,439,498)	-	222,052	(6,539)	(6,223,986)		
September	(6,223,986)	-	222,285	(6,317)	(6,008,017)		
October	(6,008,017)	-	222,519	(6,093)	(5,791,591)		
November	(5,791,591)	-	222,754	(5,870)	(5,574,708)		
December	(5,574,708)	-	222,988	(5,645)	(5,357,365)		
2022 January	(5,357,365)	-	243,705	(105,128)	(5,218,788)		
February	(5,218,788)	-	226,904	(11,189)	(5,003,073)		
March	(5,003,073)	-	227,412	(10,716)	(4,786,376)		
April	(4,786,376)	-	227,923	(10,240)	(4,568,694)		
May	(4,568,694)	-	228,435	(9,763)	(4,350,022)		
June	(4,350,022)	-	228,949	(9,283)	(4,130,356)		
July	(4,130,356)	-	229,464	(8,801)	(3,909,693)		
August	(3,909,693)	-	229,982	(8,317)	(3,688,028)		
September	(3,688,028)	-	230,502	(7,830)	(3,465,357)		
October	(3,465,357)	-	231,024	(7,342)	(3,241,674)		
November	(3,241,674)	-	231,548	(6,851)	(3,016,977)	SCHMDT	41010
December	(3,016,977)	-	232,075	(6,358)	(2,791,260)	-	-
2023 January	(2,791,260)	-	232,605	(5,863)	(2,564,518)	232,605	(57,190)
February	(2,564,518)	-	233,138	(5,365)	(2,336,745)	233,138	(57,321)
March	(2,336,745)	-	233,674	(4,865)	(2,107,936)	233,674	(57,453)
April	(2,107,936)	-	234,215	(4,363)	(1,878,084)	234,215	(57,586)
May	(1,878,084)	-	234,760	(3,859)	(1,647,182)	234,760	(57,720)
June	(1,647,182)	-	235,312	(3,352)	(1,415,223)	235,312	(57,855)
July	(1,415,223)	-	235,870	(2,843)	(1,182,195)	235,870	(57,993)
August	(1,182,195)	-	236,439	(2,332)	(948,088)	236,439	(58,132)
September	(948,088)	-	237,022	(1,818)	(712,884)	237,022	(58,276)
October	(712,884)	-	237,628	(1,302)	(476,558)	237,628	(58,425)
November	(476,558)	-	238,279	(783)	(239,062)	238,279	(58,585)
December	(239,062)	-	239,062	-	-	239,062	(58,777)
<b>Pro Forma Amort =</b>			<b>2,828,006</b>			<b>2,828,006</b>	<b>(695,313)</b>
						<b>Ref 8.6</b>	<b>Ref 8.6</b>

Note:

- Interest rate in deferral period per approved WACC from UE-263.
- Interest accrual at Modified Blended Treasury Rate as of date of the Commission's approval of the amortization (i.e. Dec 2020)

	2020	
MBTR	2.630%	Ref UM-1147

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Regulatory Assets & Liabilities Amortization**  
**Oregon Depreciation Decrease Deferral**  
**GL Account 288412 - Actuals for 12 Months Ended June 2021**

Year	Month	Accrual	Amort.	Interest	Accumulated Amount
2020	6	(71,566)		(45,327)	(7,218,264)
2020	7	(71,566)		(46,069)	(7,335,899)
2020	8	(71,566)		(46,816)	(7,454,281)
2020	9	(71,566)		(47,568)	(7,573,415)
2020	10	(71,566)		(48,325)	(7,693,306)
2020	11	(71,566)		(49,086)	(7,813,958)
2020	12	(71,566)		(49,852)	(7,935,376)
2021	1	-	220,427	(8,086)	(7,723,035)
2021	2	-	220,658	(7,866)	(7,510,243)
2021	3	-	220,890	(7,646)	(7,297,000)
2021	4	-	221,121	(7,426)	(7,083,305)
2021	5	-	221,353	(7,205)	(6,869,157)
2021	6	-	221,586	(6,984)	<b>(6,654,555)</b>

Ref 8.6.9

**GL Account Balance**  
**Account Number 288412**  
**Calendar year 2020**

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				6,527,879.58-
1		113,250.61	113,250.61-	6,641,130.19-
2		113,969.88	113,969.88-	6,755,100.07-
3		114,693.69	114,693.69-	6,869,793.76-
4		115,422.09	115,422.09-	6,985,215.85-
5		116,155.11	116,155.11-	7,101,370.96-
6		116,892.80	116,892.80-	7,218,262.76-
7		117,635.16	117,635.16-	7,335,898.92-
8		118,382.24	118,382.24-	7,454,281.16-
9		119,134.07	119,134.07-	7,573,415.23-
10		119,890.67	119,890.67-	7,693,305.90-
11		119,890.67	119,890.67-	7,813,196.57-
12	119,890.67	242,070.40	122,179.73	7,935,376.30-

**Calendar year 2021**

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				7,935,376.30-
1	220,427.12	8,086.00	212,341.12	7,723,035.18-
2	220,658.15	7,866.46	212,791.69	7,510,243.49-
3	220,889.51	7,646.46	213,243.05	7,297,000.44-
4	221,121.23	7,425.99	213,695.24	7,083,305.20-
5	221,353.29	7,205.05	214,148.24	6,869,156.96-
6	221,585.71	6,983.64	214,602.07	6,654,554.80-
7	221,818.50	6,761.77	215,056.73	6,439,498.16-
8	222,051.66	6,539.42	215,512.24	6,223,985.92-
9	222,285.21	6,316.60	215,968.61	6,008,017.31-
10	222,519.16	6,093.32	216,425.84	5,791,591.47-
11	222,753.52	5,869.56	216,883.96	5,574,707.51-
12	222,988.30	5,645.32	217,342.98	5,357,364.53-

**PacifiCorp  
Oregon General Rate Case - December 2023  
FERC 105 (PHFU) Adjustment**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Remove PHFU	105	1	(10,603,216)	SG	26.070%	(2,764,295)	
Remove PHFU	105	1	(683,318)	CA	Situs	-	
Remove PHFU	105	1	(6,893,577)	OR	Situs	(6,893,577)	
Remove PHFU	105	1	(5,715,537)	UT	Situs	-	
Remove PHFU	105	1	(601)	WYP	Situs	-	
			<u>(23,896,248)</u>			<u>(9,657,872)</u>	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.



PacifiCorp  
Oregon General Rate Case - December 2023  
FERC 105 (Plant Held for Future Use)

Primary Account		Secondary Account		Alloc	Total
1050000	Plant Held for Future Use	3401000	LAND OWNED IN FEE	SG	8,923,302
1050000	Plant Held for Future Use	3501000	LAND OWNED IN FEE	SG	925,352
1050000	Plant Held for Future Use	3502000	LAND RIGHTS	SG	754,562
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	CA	683,318
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	UT	5,715,537
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	WYP	601
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	OR	3,912,456
1050000	Plant Held for Future Use	3891000	LAND OWNED IN FEE	OR	2,981,121
<b>Total</b>					<b>23,896,248</b>

REF 8.7

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Pension & Other Post-retirement Balances Removal**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Net Prepaid Balance	128	1	(28,656,862)	SO	27.173%	(7,786,953)	8.8.1
Net Prepaid Balance	182M	1	(406,817,630)	SO	27.173%	(110,544,888)	8.8.1
Net Prepaid Balance	2283	1	74,432,333	SO	27.173%	20,225,559	8.8.1
			<u>(361,042,159)</u>			<u>(98,106,282)</u>	
<b>Adjustment to Tax:</b>							
ADIT Balances	190	1	(21,054,777)	SO	27.173%	(5,721,232)	8.8.2
ADIT Balances	283	1	109,063,328	SO	27.173%	29,635,867	8.8.2
			<u>88,008,551</u>			<u>23,914,636</u>	

**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**  
**Oregon General Rate Case - December 2023**  
**Pension & Other Post-retirement Balances Removal**

PAGE 8.8.1

**Pension & Postretirement**

<b>FERC Account</b>	<b>Factor</b>	<b>June 2021 End of Period Balances</b>	<b>Ref</b>
128	SO	28,656,862	<b>8.8</b>
182M	SO	406,817,630	<b>8.8</b>
2283	SO	(74,432,333)	<b>8.8</b>
		<b>361,042,159</b>	<b>8.8</b>

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Pension & Other Post-retirement Balances Removal**  
**Tax Support**

	<b>Sch. M Number</b>	<b>SAP Account</b>	<b>EOP 6/2021 Per Tax Model</b>	<b>Adjustment</b>		
190	DTA 720.800	FAS 158 Pension Liability	720.800	287460	18,300,380	(18,300,380)
190	FAS 158	Post-Retirement Liability	720.810	287461	-	-
190	DTA 320.279	Reg Liability FAS 158 Post-Ret	320.279	287198	2,754,397	(2,754,397)
283	DTL 720.805	FAS 158 Pension Asset	720.800	287569	(2,045,357)	2,045,357
283	DTL 720.815	FAS 158 Post-Retirement Asset	720.815	286909	(4,240,952)	4,240,952
283	DTL 320.270	Reg Asset FAS 158 Pension	320.270	287738	(103,189,035)	103,189,035
283	DTL 320.280	Reg Asset FAS 158 Post-Ret	320.280	287739	412,016	(412,016)
					<u>(88,008,551)</u>	<u>88,008,551</u>

Summarize Tax Adjustment by Allocation Factor

190  
283

SO  
SO

	<b>EOP 6/2021</b>	<b>Adjustment</b>	
	21,054,777	(21,054,777)	<b>Ref. 8.8</b>
	(109,063,328)	109,063,328	<b>Ref. 8.8</b>
	<u>(88,008,551)</u>	<u>88,008,551</u>	

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Remove Rolling Hills**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Other Plant	341	1	(3,478,252)	SG	26.070%	(906,792)	
Other Plant	343	1	(170,634,366)	SG	26.070%	(44,484,963)	
Other Plant	344	1	(7,930,556)	SG	26.070%	(2,067,523)	
Other Plant	345	1	(12,436,383)	SG	26.070%	(3,242,207)	
Other Plant	346	1	(659,497)	SG	26.070%	(171,933)	
			<u>(195,139,054)</u>			<u>(50,873,419)</u>	8.9.1
<b>Adjustment to Depreciation Reserve:</b>							
Other Plant	108OP	1	(17,881,562)	SG	26.070%	(4,661,784)	8.9.1
<b>Adjustment to O&amp;M Expense:</b>							
Administrative & General	929	1	(431,525)	SO	27.173%	(117,259)	8.9.1
Misc. Oth. Power Supply	549	1	(28,437)	SG	26.070%	(7,414)	8.9.1
Misc. Oth. Power Supply	553	1	(1,112,621)	SG	26.070%	(290,064)	8.9.1
<b>Adjustment to Tax:</b>							
Schedule M Adjustment	SCHMAP	1	85	SCHMDEXP	22.648%	19	
Schedule M Adjustment	SCHMDT	1	(10,880,231)	TAXDEPR	26.410%	(2,873,436)	
Schedule M Adjustment	SCHMDT	1	(9,068)	GPS	27.173%	(2,464)	
Deferred Tax Expense	41010	1	(2,675,079)	TAXDEPR	26.410%	(706,480)	
Deferred Tax Expense	41010	1	(2,230)	GPS	27.173%	(606)	
Deferred Tax Expense	41110	1	(25)	OR	Situs	(25)	
Accumulated Def Inc Tax Balance	282	1	13,118,713	OR	Situs	13,118,713	

**Description of Adjustment:**

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 2021. This treatment is consistent with Commission Order No. 08-548. Depreciation expense for Rolling Hills is removed in Adjustment 6.1, Depreciation / Amortization Expense Adjustment.

**PacifiCorp**  
**Oregon General Rate - December 2023**  
**Remove Rolling Hills**

<b>Rate Base Amounts</b>	<b>FERC Account</b>	<b>EOP 12 ME Jun 2021</b>	<b>Ref.</b>
<b>Capital</b>			
Other Plant	341	3,478,252	
Other Plant	343	170,634,366	
Other Plant	344	7,930,556	
Other Plant	345	12,436,383	
Other Plant	346	659,497	
		<u>195,139,054</u>	8.9
<b>Depreciation Reserve</b>			
Other Plant	108OP	17,881,562	8.9

<b>Expense Amounts</b>	<b>FERC Account</b>	<b>12 ME Jun 2021</b>	<b>Ref.</b>
<b>Operation &amp; Maintenance Expense</b>			
Administrative & General	929	431,525	8.9
Misc. Oth. Power Supply	549	28,437	8.9
Misc. Oth. Power Supply	553	1,112,621	8.9

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Deer Creek Mine Closure**

PAGE 8.10

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
<u>Remove base period expense</u>							
Closure cost amortization - WY	506	1	(35,379,413)	SG	26.070%	(9,223,534)	8.10.1
<u>Add pro forma expense</u>							
UMWA Pension Withdrawal Liability Pymt	926	1	2,967,013	SO	27.173%	806,229	8.10.2
<b>Adjustment to Rate Base:</b>							
<u>Remove base period regulatory assets</u>							
Closure Costs	182M	1	(75,945,690)	SE	25.068%	(19,038,168)	B-16
Unrecovered Plant	182M	1	(2,436,501)	SE	25.068%	(610,785)	B-16
Unrecovered Plant	182M	1	1,633,354	OR	Situs	1,633,354	B-16
Post-Retire. Settlement Loss	182M	1	(8,323,073)	SO	27.173%	(2,261,635)	B-16
Post-Retire. Settlement Savings	182M	1	9,264,033	OR	Situs	9,264,033	B-16
<b>Adjustment to Tax:</b>							
<u>Remove Base Period Tax</u>							
Schedule M Addition	SCHMAT	1	(18,093,654)	SE	25.068%	(4,535,742)	
Schedule M Addition	SCHMAT	1	(3,702,799)	SO	27.173%	(1,006,165)	
Schedule M Deduction	SCHMDT	1	(3,264,033)	SE	25.068%	(818,232)	
Schedule M Deduction	SCHMDT	1	(248,200)	OR	Situs	(248,200)	
Def Income Tax Expense	41110	1	4,448,614	SE	25.068%	1,115,185	
Def Income Tax Expense	41110	1	910,392	SO	27.173%	247,382	
Def Income Tax Expense	41010	1	(802,515)	SE	25.068%	(201,176)	
Def Income Tax Expense	41010	1	(61,024)	OR	Situs	(61,024)	
Accum Def Income Tax Balance	283	1	(29,952,417)	SE	25.068%	(7,508,512)	
Accum Def Income Tax Balance	283	1	68,930,513	SE	25.068%	17,279,594	
Accum Def Income Tax Balance	190	1	(28,303,872)	SE	25.068%	(7,095,253)	
Accum Def Income Tax Balance	283	1	595,182	SO	27.173%	161,729	
Accum Def Income Tax Balance	283	1	(2,330,252)	OR	Situs	(2,330,252)	

**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 being 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 are being moved from the TAM to base rates per resolution in Docket No. UE 374 and UE No. 375.

**PacifiCorp  
 Oregon General Rate Case - December 2023  
 Deer Creek Mine Adjustment  
 Treatment of Deer Creek Unrecovered Plant**

Deer Creek Closure costs in Wyoming are being allocated on an SG factor which impacts Oregon unadjusted results. We need to remove this from unadjusted results.

	<u>Amort</u>	<u>FERC Account</u>	<u>Allocator</u>	<u>Ref</u>
Wyoming closure cost amortization in unadj results	<b>35,379,413</b>	<b>506</b>	<b>SG</b>	<b>8.10</b>



**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Deer Creek Mine Adjustment**  
**UMWA Pension Withdrawal Liability Payment**

Fiscal Year	Posting period	Account Number	FERC Account	FERC Location	Description	In transaction currency
2021	6	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2021	5	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2021	4	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2021	3	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2021	2	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2021	1	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2020	12	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2020	11	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2020	10	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2020	9	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2020	8	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2020	7	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
Total						<b>2,967,013</b>
						<b>Ref. 8.10</b>

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Emissions Control Investment Adjustment**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Hunter Clean Air Disallowance	312	1	(4,649,941)	SG	26.070%	(1,212,256)	8.11.1
Hunter Clean Air Disallowance	108SP	1	325,130	SG	26.070%	84,762	8.11.1
<b>Adjustment to Expense:</b>							
Hunter Clean Air Disallowance	403SP	1	(325,130)	SG	26.070%	(84,762)	8.11.1
<b>Adjustment to Return:</b>							
JB U3 & U4 Return Disallowance	930	3	(1,669,716)	OR	Situs	(1,669,716)	8.11.2
<b>Adjustment to Tax:</b>							
Schedule M Adjustment	SCHMAT	1	(325,130)	SG	26.070%	(84,763)	
Schedule M Adjustment	SCHMDT	1	(128,808)	SG	26.070%	(33,581)	
Deferred Income Tax Expense	41110	1	79,938	SG	26.070%	20,840	
Deferred Income Tax Expense	41010	1	(31,670)	SG	26.070%	(8,256)	
Accumulated Def Inc Tax Balance	282	1	471,095	SG	26.070%	122,816	

**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 2023**  
**Emissions Control Equipment Adjustment**  
**Hunter Clean Air Equipment Summary**

PAGE 8.11.1

**End of Period Balances as of Dec 31 2022**

EPIS Balance	81,171,892
Steam Plant Reserve	(34,672,480)
Net Book Value	<u>46,499,411</u>

**Disallowance Adjustments**

Ordered 10% Disallowance	4,649,941	Ref 8.11
Depreciation Rate <sup>1</sup>	<u>6.992%</u>	
Depreciation Expense	325,130	Ref 8.11
Depreciation Reserve	(325,130)	Ref 8.11

<sup>1</sup> Actual composite steam depreciation rate for June 2021.

**PacifiCorp  
Oregon General Rate Case - December 2023  
Emissions Control Equipment Adjustment  
Jim Bridger Unit 3 & 4 SCR Return Adjustments**

PAGE 8.11.2

**Pro Forma Adjustment**

Net Book Value - End of Period Dec 2022

Pre-Tax Rate of Return  
Return on Rate Base\_Rate of Return

Return - Cost of Long-Term Debt  
Return on Rate Base\_Cost of Debt

**Adjustment to Return**

System Generation Factor (SG)

<b>Total Co.</b>	<b>OR Allocated</b>
142,268,368	37,089,850
8.88%	8.88%
12,636,012	3,294,252
4.38%	4.38%
6,231,355	1,624,535
<b>(6,404,658)</b>	<b>(1,669,716)</b>

**Ref 8.11**

26.070%

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Summary of Variables**

PAGE 8.11.3

**Proposed Capital Structure and Costs**

	Capital Structure	Embedded Cost	Weighted Cost	Tax Net-to-Gross Bump-up	Pre-Tax Revenue Requirement
Debt	47.74%	4.380%	2.091%		2.091%
Preferred	0.01%	6.750%	0.001%	132.60%	0.001%
Common	52.25%	9.800%	5.121%	132.60%	6.790%
Total	100.00%		7.212%		8.882%

Merged Effective Tax Rate	24.587%
Pre-Tax Bump-up Factor	132.60%

**2020 Protocol Allocation Factors**

Forecast 2023 SG Factor	26.070%
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**PacifiCorp  
Oregon General Rate Case - December 2023  
Transmission Project Adjustment**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Transmission	352	3	(237,818)	SG	26.070%	(62,000)	8.12.1
Distribution	361	3	(120,000)	OR	Situs	(120,000)	8.11.2
			<u>(357,818)</u>			<u>(182,000)</u>	
<b>Adjustment to Reserve:</b>							
Transmission	108TP	3	17,650	SG	26.070%	4,601	8.12.1
Distribution	108364	3	23,910	OR	Situs	23,910	8.11.2
			<u>41,560</u>			<u>28,512</u>	
<b>Adjustment to Tax:</b>							
ADIT - Transmission	282	3	3,564	OR	Situs	3,564	
ADIT - Distribution	282	3	7,187	OR	Situs	7,187	
			<u>10,751</u>			<u>10,751</u>	

**Description of Adjustment:**

Rate base disallowances for specific transmission projects as discussed on Order No. 20-473, Docket No. UE 374.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Transmission Project Adjustment**

**Wallula-to-McNary Project**

In-Service Date Jan-19  
Depreciation Composite Rate 1.875%

		* <u>Gross Plant</u>	<u>Depreciation Expense</u>	<u>Depreciation Reserve</u>	<u>Net Book Value</u>
2020	June	62,000	97	(1,695)	60,305
	July	62,000	97	(1,792)	60,208
	August	62,000	97	(1,889)	60,111
	September	62,000	97	(1,986)	60,014
	October	62,000	97	(2,083)	59,917
	November	62,000	97	(2,180)	59,820
	December	62,000	97	(2,277)	59,723
2021	January	62,000	97	(2,373)	59,627
	February	62,000	97	(2,470)	59,530
	March	62,000	97	(2,567)	59,433
	April	62,000	97	(2,664)	59,336
	May	62,000	97	(2,761)	59,239
	June	62,000	97	(2,858)	59,142
	July	62,000	97	(2,955)	59,045
	August	62,000	97	(3,051)	58,949
	September	62,000	97	(3,148)	58,852
	October	62,000	97	(3,245)	58,755
	November	62,000	97	(3,342)	58,658
	December	62,000	97	(3,439)	58,561
2022	January	62,000	97	(3,536)	58,464
	February	62,000	97	(3,633)	58,367
	March	62,000	97	(3,730)	58,270
	April	62,000	97	(3,826)	58,174
	May	62,000	97	(3,923)	58,077
	June	62,000	97	(4,020)	57,980
	July	62,000	97	(4,117)	57,883
	August	62,000	97	(4,214)	57,786
	September	62,000	97	(4,311)	57,689
	October	62,000	97	(4,408)	57,592
	November	62,000	97	(4,505)	57,495
	December	62,000	97	<b>(4,601)</b>	57,399

**Ref. 8.12**

\* Oregon's allocated amount

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Transmission Project Adjustment**

**Threemile Canyon Project**

In-Service Date Apr-15  
Depreciation Composite Rate 2.585%

		<u>Gross Plant</u>	<u>Depreciation Expense</u>	<u>Depreciation Reserve</u>	<u>Net Book Value</u>
2020	June	120,000	258	(16,155)	103,845
	July	120,000	258	(16,414)	103,586
	August	120,000	258	(16,672)	103,328
	September	120,000	258	(16,931)	103,069
	October	120,000	258	(17,189)	102,811
	November	120,000	258	(17,448)	102,552
	December	120,000	258	(17,706)	102,294
2021	January	120,000	258	(17,965)	102,035
	February	120,000	258	(18,223)	101,777
	March	120,000	258	(18,482)	101,518
	April	120,000	258	(18,740)	101,260
	May	120,000	258	(18,999)	101,001
	June	120,000	258	(19,257)	100,743
	July	120,000	258	(19,516)	100,484
	August	120,000	258	(19,774)	100,226
	September	120,000	258	(20,033)	99,967
	October	120,000	258	(20,291)	99,709
	November	120,000	258	(20,550)	99,450
	December	120,000	258	(20,808)	99,192
2022	January	120,000	258	(21,067)	98,933
	February	120,000	258	(21,325)	98,675
	March	120,000	258	(21,584)	98,416
	April	120,000	258	(21,842)	98,158
	May	120,000	258	(22,101)	97,899
	June	120,000	258	(22,359)	97,641
	July	120,000	258	(22,618)	97,382
	August	120,000	258	(22,876)	97,124
	September	120,000	258	(23,135)	96,865
	October	120,000	258	(23,393)	96,607
	November	120,000	258	(23,652)	96,348
	December	120,000	258	<b>(23,910)</b>	96,090 <b>Ref. 8.12</b>



**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Cholla Unit 4 Retirement**

PAGE 8.13

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense</b>							
Remove O&M expense	506	1	(14,648,254)	SG	26.070%	(3,818,850)	8.13.1
Add Closure Cost Reg. Asset Amort. Exp	407	3	937,832	SG	26.070%	244,496	8.13.2
Add Property Tax Reg. Asset Amort. Exp	407	3	518,123	OR	Situs	518,123	8.13.3
<b>Adjustment to Rate Base</b>							
Remove M&S Inventory Balance	154	1	(5,341,897)	SG	26.070%	(1,392,651)	8.13.1
Remove Nonunion Severance Reg. Asset	182M	1	(2,700,000)	SG	26.070%	(703,899)	8.13.1
Remove Safe Harbor Lease Reg. Asset	182M	1	(836,167)	SG	26.070%	(217,992)	8.13.1
Remove Contra Reg. Asset Lease & Sev	182M	1	920,203	OR	Situs	920,203	8.13.1
Remove Cholla Property Tax Reg Asset	182M	1	(299,987)	OR	Situs	(299,987)	8.13.3
Add Dec. 2023 Cholla Closure Cost	182M	3	2,344,579	SG	26.070%	611,240	8.13.2
<b>Adjustment to Tax:</b>							
Property tax Reg asset amort - Sch M	SCHMAT	3	519,052	OR	Situs	519,052	
Property tax Reg asset amort - Def Inc Tax	41110	3	(127,618)	OR	Situs	(127,618)	
Property tax Reg asset amort - ADIT	283	3	(56,568)	OR	Situs	(56,568)	
Closure Cost Reg asset amort - Sch M	SCHMAT	3	937,832	SG	26.070%	244,496	
Closure Cost Reg asset amort - Def Inc Tax	41110	3	(230,581)	SG	26.070%	(60,113)	
Closure Cost Reg asset amort - ADIT	283	3	(576,453)	SG	26.070%	(150,283)	
Remove Contra Reg Asset Lease & Sev	SCHMAT	3	(920,203)	OR	Situs	(920,203)	
Remove Contra Reg Asset Lease & Sev	41110	3	226,247	OR	Situs	226,247	
Remove Contra Reg Asset Lease & Sev	283	3	(226,247)	OR	Situs	(226,247)	

**Description of Adjustment:**

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 closure cost.

This adjustment removes O&M and materials and supplies balances from Oregon's Results. This adjustment then adds back into results the unrecovered closure and property tax regulatory asset balances and amortizations associated with the Test Period. The regulatory assets are being amortized over a three year period.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Cholla Unit 4 Retirement**  
**Cholla Unit 4 - Non-EPIS Booked Balances**

PAGE 8.13.1

	FERC account	Factor	12 ME June 2021
O&M Expenses	506	SG	<b>\$ 14,648,254</b>

**Ref 8.13**

	FERC account		EOP June 2021
Material & Supplies	154	SG	<b>\$ 5,341,897</b>

**Ref 8.13**

	FERC account		EOP June 2021
Reg Asset-Cholla U4-Nonunion Severance	182M	SG	<b>\$ 2,700,000</b>
Reg Asset-Cholla U4-Safe Harbor Lease	182M	SG	<b>\$ 836,167</b>
Contra Reg Asset-Cholla U4 Closure-OR	182M	OR	<b>\$ (920,203)</b>

**Ref 8.13**

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Cholla Unit 4 Retirement**  
**Treatment of Cholla Unrecovered Closure Items**

	<b>Unrecovered Costs</b>	<b>13 Mo. Avg. Dec 2023</b>
Safe Harbor Lease Payment	113,495	94,579
Nonunion Severance	2,700,000	2,250,000
<b>Total Unrecovered Closure Items</b>	<b>2,813,495</b>	<b>2,344,579</b>

below  
below

Ref. 8.13

	<u>Beg Bal</u>		<u>Amortization</u>		Total	<u>End Bal</u>	
	<u>Nonunion Severance</u>	<u>Safe Harbor Lease Pmt</u>	<u>Nonunion Severance</u>	<u>Safe Harbor Lease Pmt</u>			
Dec-22						2,813,495	<b>Above</b>
Jan-23	2,700,000	113,495	(75,000)	(3,153)	(78,153)	2,735,343	
Feb-23	2,625,000	110,343	(75,000)	(3,153)	(78,153)	2,657,190	
Mar-23	2,550,000	107,190	(75,000)	(3,153)	(78,153)	2,579,037	
Apr-23	2,475,000	104,037	(75,000)	(3,153)	(78,153)	2,500,885	
May-23	2,400,000	100,885	(75,000)	(3,153)	(78,153)	2,422,732	
Jun-23	2,325,000	97,732	(75,000)	(3,153)	(78,153)	2,344,579	
Jul-23	2,250,000	94,579	(75,000)	(3,153)	(78,153)	2,266,427	
Aug-23	2,175,000	91,427	(75,000)	(3,153)	(78,153)	2,188,274	
Sep-23	2,100,000	88,274	(75,000)	(3,153)	(78,153)	2,110,121	
Oct-23	2,025,000	85,121	(75,000)	(3,153)	(78,153)	2,031,969	
Nov-23	1,950,000	81,969	(75,000)	(3,153)	(78,153)	1,953,816	
Dec-23	1,875,000	78,816	(75,000)	(3,153)	(78,153)	1,875,663	<b>13 Mo. Avg.</b>
			<b>Amort exp. 12 ME Dec-23</b>		<b>(937,832)</b>		<b>2,344,579</b>
					<b>Ref. 8.13</b>		

PacifiCorp  
Oregon General Rate Case - December 2023  
Cholla Unit 4 Retirement  
Treatment of Cholla Property Taxes

Oregon Property Tax Deferral 2021 **639,589** Ref. 8.13.4

	End-of-Period June 2021
Cholla Property Taxes Reg Asset	299,987

Ref. 8.13

	12 ME June 2021	12 ME Dec 2023	Difference
Cholla Property Taxes Expense	(299,058)	219,065	<b>518,123</b>

Ref. 8.13

<u>Date</u>	<u>Beg Bal</u>	<u>Amortization</u>	<u>Interest*</u>	<u>End Bal</u>
Dec-22				639,589
Jan-23	639,589	(18,255)	956	622,290
Feb-23	622,290	(18,255)	930	604,964
Mar-23	604,964	(18,255)	904	587,612
Apr-23	587,612	(18,255)	877	570,234
May-23	570,234	(18,255)	851	552,830
Jun-23	552,830	(18,255)	825	535,399
Jul-23	535,399	(18,255)	798	517,942
Aug-23	517,942	(18,255)	772	500,458
Sep-23	500,458	(18,255)	745	482,948
Oct-23	482,948	(18,255)	719	465,411
Nov-23	465,411	(18,255)	692	447,848
Dec-23	447,848	(18,255)	665	430,258
<b>Amort exp. 12 months ending December 2023</b>		<b>(219,065)</b>		

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Cholla Unit 4 Retirement**  
**Treatment of Cholla Property Taxes**

PAGE 8.13.4

**Oregon Property Tax Deferral 2021** **639,589**

<u>Date</u>	<u>Beg Bal</u>	<u>Deferral</u>	<u>Interest*</u>	<u>End Bal</u>
Jan-21		52,015	27	52,042
Feb-21	52,042	52,015	81	104,137
Mar-21	104,137	52,015	134	156,287
Apr-21	156,287	52,015	188	208,490
May-21	208,490	52,015	242	260,747
Jun-21	260,747	52,015	296	313,058
Jul-21	313,058	52,015	350	365,423
Aug-21	365,423	52,015	404	417,843
Sep-21	417,843	52,015	459	470,316
Oct-21	470,316	52,015	513	522,844
Nov-21	522,844	52,015	567	575,426
Dec-21	575,426	52,015	621	628,062
Jan-22	628,062	-	953	629,015
Feb-22	629,015	-	954	629,969
Mar-22	629,969	-	955	630,924
Apr-22	630,924	-	957	631,881
May-22	631,881	-	958	632,839
Jun-22	632,839	-	960	633,799
Jul-22	633,799	-	961	634,761
Aug-22	634,761	-	963	635,723
Sep-22	635,723	-	964	636,687
Oct-22	636,687	-	966	637,653
Nov-22	637,653	-	967	638,620
Dec-22	638,620	-	969	<b>639,589</b>

**Ref. 8.13.3**

\*MBT Rate 2021 1.240%

\*MBT Rate 2022 1.820%

**PacifiCorp  
Oregon General Rate Case - December 2023  
Wind Project Deferrals Amortization**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Cedar Springs II Amort.	407	3	256,632	OR	Situs	256,632	8.14.1
TB Flats Amort.	407	3	6,140,445	OR	Situs	6,140,445	8.14.4
			6,397,077			6,397,077	
<b>Adjustment to Tax:</b>							
Cedar Springs II Amort - Sch M	SCHMAT	3	256,632	OR	Situs	256,632	
Cedar Springs II Amort - Ditexp	41110	3	(63,096)	OR	Situs	(63,096)	
TB Flats Amort - Sch M	SCHMAT	3	6,140,445	OR	Situs	6,140,445	
TB Flats Amort - Ditexp	41110	3	(1,509,732)	OR	Situs	(1,509,732)	

**Description of Adjustment:**

This adjustment adds into test period results the amortization of deferred revenue requirement associated with Cedar Springs II wind project, which went into service in December 2020, one month prior to new rates from the 2021 Oregon General Rate Case (GRC) became effective. Cedar Springs II was part of EV 2020 wind projects determined to be prudent in the 2021 GRC (Order 20-473). The Company has a pending application for deferral treatment (Docket No. UM 2134) of the revenue requirement for Cedar Springs II in front of the Commission, for the approximately one month period that the facility is in service and serving customers, but its costs were not yet reflected in customer rates.

This adjustment also adds into test period results the amortization deferred revenue requirement, net of net power cost and production tax credit benefits, associated with TB Flats. TB Flats was also part of the EV 2020 wind projects determined to be prudent in the 2021 GRC. A portion of the project that was complete and in service by 12/30/2021 is already reflected in rates. Upon the completion of the remainder of the project in July 2021, the Company filed a request for deferral treatment of the revenue requirement for TB Flats (Docket No. UM 2186).

This adjustments proposes a three-year amortization period, starting January 1, 2023, for deferred net revenue requirement associated with these wind projects not having been or is being recovered in customer rates.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Wind Project Deferrals Amortization**  
**Cedar Springs II - Amortization Summary**

	<u>Amortization</u>
Base Period Amount (below)	-
Pro Forma Amount (below)	256,632
Adjustment:	<u>256,632</u>
	<u>Ref. 8.14</u>

In-Service Date 12/8/2020

	Opening Bal.	Accrual <sup>1</sup>	Amortization	Interest <sup>2,3</sup>	Ending Bal.		
December	-	647,365	-	1,525	648,890		
2021 January	648,890	-	-	3,859	652,749		
February	652,749	-	-	3,882	656,632		
March	656,632	-	-	3,905	660,537		
April	660,537	-	-	3,929	664,466		
May	664,466	-	-	3,952	668,418		
June	668,418	-	-	3,976	672,393		
July	672,393	-	-	3,999	676,392		
August	676,392	-	-	4,023	680,415		
September	680,415	-	-	4,047	684,462		
October	684,462	-	-	4,071	688,533		
November	688,533	-	-	4,095	692,628		
December	692,628	-	-	4,120	696,748		
2022 January	696,748	-	-	4,144	700,892		
February	700,892	-	-	4,169	705,061		
March	705,061	-	-	4,193	709,254		
April	709,254	-	-	4,218	713,472		
May	713,472	-	-	4,243	717,716		
June	717,716	-	-	4,269	721,985		
July	721,985	-	-	4,294	726,279		
August	726,279	-	-	4,320	730,598		
September	730,598	-	-	4,345	734,944		
October	734,944	-	-	4,371	739,315		
November	739,315	-	-	4,397	743,712		
December	743,712	-	-	4,423	748,136	<b>SCHMDT</b>	<b>41010</b>
2023 January	748,136	-	21,386	1,151	727,900	21,386	(5,258)
February	727,900	-	21,386	1,120	707,635	21,386	(5,258)
March	707,635	-	21,386	1,089	687,338	21,386	(5,258)
April	687,338	-	21,386	1,059	667,011	21,386	(5,258)
May	667,011	-	21,386	1,028	646,653	21,386	(5,258)
June	646,653	-	21,386	997	626,264	21,386	(5,258)
July	626,264	-	21,386	966	605,844	21,386	(5,258)
August	605,844	-	21,386	935	585,393	21,386	(5,258)
September	585,393	-	21,386	904	564,911	21,386	(5,258)
October	564,911	-	21,386	873	544,398	21,386	(5,258)
November	544,398	-	21,386	842	523,854	21,386	(5,258)
December	523,854	-	21,386	811	503,278	21,386	(5,258)
	<b>Pro Forma Amort =</b>		<b>256,632</b>			<b>256,632</b>	<b>(63,096)</b>
						<u>Ref 8.14</u>	<u>Ref 8.14</u>

Note:

1. Ref Page 8.14.2
2. 2020 Interest rate is approved WACC from UE-263. 2021 Interest rate is approved WACC from UE-374.
3. Interest rate in amortization period per UM-1147, MBT Rate, approved January 14, 2022.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Wind Project Deferrals Amortization**  
**Cedar Springs II Revenue Requirement Summary**

		<b>Cedar Springs II Deferral</b>		
		<b>Total Company</b>	<b>2020 Allocation %</b>	<b>Oregon Allocated</b>
<b>Revenue Requirement</b>	<b>Factor</b>			
Capital Investment				
Wind Generation	SG	244,911,084	26.456%	64,793,297
Transmission	SG	81,206,115	26.456%	21,483,764
General	SG	1,389,974	26.456%	367,729
Depreciation Reserve				
Wind Generation	SG	(337,223)	26.456%	(89,215)
Transmission	SG	(59,211)	26.456%	(15,665)
General	SG	(2,029)	26.456%	(537)
Accumulated DIT Balance	SG	<u>(3,173,785)</u>	26.456%	<u>(839,652)</u>
Net Rate Base		323,934,925		85,699,722
Pre-Tax Rate of Return		<u>9.296%</u>		<u>9.296%</u>
Pre-Tax Return on Rate Base		30,111,712		7,966,308
Dec 2020 Pre-Tax Return		2,509,309		663,859
Operation & Maintenance	SG	135,552	26.456%	35,861
Depreciation				
Wind Generation	SG	337,223	26.456%	89,215
Transmission	SG	59,211	26.456%	15,665
General	SG	2,029	26.456%	537
Deferred Income Tax Expense	SG	4	26.456%	1
Property Taxes	GPS	246,537	27.337%	67,397
Dec 2020 Rev. Reqt. Before Gross-up		33,401,577		872,535
<b>Revenue Requirement for Deferral (12/8/2020 - 12/31/2020)</b>				<b>647,365</b>



PacifiCorp  
Oregon General Rate Case - December 2023  
Wind Project Deferrals Amortization  
Cedar Springs II Wind Project Capital Additions  
Deferral Application - UM 2134

In-Service Date Dec-20

Cedar Springs Wind Project 200 MW 2020

	<u>Gross Plant In Service</u>			<u>Accumulated Depreciation</u>		
	<u>Wind Generation</u>	<u>Transmission</u>	<u>General</u>	<u>Wind Generation</u>	<u>Transmission</u>	<u>General</u>
Dec-20	244,911,084	22,842,576	1,375,138	(337,223)	(16,656)	(2,007)

	<u>Depreciation Expense</u>			<u>O&amp;M Expenses</u>
	<u>Wind Generation</u>	<u>Transmission</u>	<u>General</u>	
Dec-20	337,223	16,656	2,007	135,552
<i>Depreciation Rate</i>	<i>3.305%</i>	<i>1.750%</i>	<i>3.503%</i>	

Q712 Cedar Springs Wind 1

	<u>Gross Plant In Service</u>		<u>Accumulated Reserves</u>	
	<u>Transmission</u>	<u>General</u>	<u>Transmission</u>	<u>General</u>
Dec-20	58,363,539	14,836	(42,555)	(22)

	<u>Depreciation Expense</u>	
	<u>Transmission</u>	<u>General</u>
Dec-20	42,555	22
<i>Depreciation Rate</i>	<i>1.750%</i>	<i>3.503%</i>

	<u>Tax: Wind and Transmission</u>				
	<u>SCHMAT</u>	<u>SCHMDT</u>	<u>Def Inc Tax Exp</u>	<u>Flow-thru</u>	<u>ADIT</u>
Dec-20	398,463	(13,309,827)	3,174,466	4	(3,173,785)

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Wind Project Deferrals Amortization**  
**TB Flats - Amortization Summary**

	<b>Amortization</b>
Base Period Amount (below)	-
Pro Forma Amount (below)	6,140,445
Adjustment:	<u>6,140,445</u>
	<b>Ref. 8.14</b>

**In-Service Date 7/26/2021**

	Opening Bal.	Accrual <sup>1</sup>	Amortization	Interest <sup>2,3</sup>	Ending Bal.		
2021 June	-	-	-	-	-		
July		146,428	-	435	146,863		
August	146,863	907,853	-	3,573	1,058,290		
September	1,058,290	907,853	-	8,994	1,975,137		
October	1,975,137	907,853	-	14,447	2,897,438		
November	2,897,438	907,853	-	19,933	3,825,224		
December	3,825,224	907,853	-	25,451	4,758,528		
2022 January	4,758,528	907,853	-	31,002	5,697,384		
February	5,697,384	907,853	-	36,586	6,641,823		
March	6,641,823	907,853	-	42,203	7,591,879		
April	7,591,879	907,853	-	47,854	8,547,586		
May	8,547,586	907,853	-	53,538	9,508,978		
June	9,508,978	907,853	-	59,256	10,476,087		
July	10,476,087	1,153,419	-	65,738	11,695,244		
August	11,695,244	1,153,419	-	72,989	12,921,652		
September	12,921,652	1,153,419	-	80,284	14,155,355		
October	14,155,355	1,153,419	-	87,621	15,396,395		
November	15,396,395	1,153,419	-	95,003	16,644,816	<b>SCHMDT</b>	<b>41010</b>
December	16,644,816	1,153,419	-	102,428	17,900,662		
2023 January	17,900,662	-	511,704	27,537	17,416,496	511,704	(125,811)
February	17,416,496	-	511,704	26,803	16,931,595	511,704	(125,811)
March	16,931,595	-	511,704	26,068	16,445,959	511,704	(125,811)
April	16,445,959	-	511,704	25,331	15,959,587	511,704	(125,811)
May	15,959,587	-	511,704	24,593	15,472,476	511,704	(125,811)
June	15,472,476	-	511,704	23,855	14,984,627	511,704	(125,811)
July	14,984,627	-	511,704	23,115	14,496,038	511,704	(125,811)
August	14,496,038	-	511,704	22,374	14,006,708	511,704	(125,811)
September	14,006,708	-	511,704	21,632	13,516,636	511,704	(125,811)
October	13,516,636	-	511,704	20,888	13,025,820	511,704	(125,811)
November	13,025,820	-	511,704	20,144	12,534,261	511,704	(125,811)
December	12,534,261	-	511,704	19,398	12,041,955	511,704	(125,811)
	<b>Pro Forma Amort =</b>		<b>6,140,445</b>			<b>6,140,445</b>	<b>(1,509,732)</b>

Note:

1. Ref Page 8.14.5
2. 2021 Interest rate in deferral period per approved WACC from UE-374.
3. Interest rate in amortization period per UM-1147, MBT Rate, approved January 14, 2022.

PacifiCorp  
Oregon General Rate Case - December 2023  
Wind Project Deferrals Amortization  
TB Flats Revenue Requirement Summary

		TB Flats Deferral - Year 1		
		Total Company	2021 Allocation %	Oregon Allocated
<b>Revenue Requirement</b>	<b>Factor</b>			
Capital Investment				
Wind Generation	SG	401,588,103	26.023%	104,503,797
Transmission	SG	46,176,918	26.023%	12,016,450
General	SG	1,507,051	26.023%	392,174
Depreciation Reserve				
Wind Generation	SG	(16,092,843)	26.023%	(4,187,781)
Transmission	SG	(974,922)	26.023%	(253,700)
General	SG	(57,399)	26.023%	(14,937)
Accumulated DIT Balance	SG	<u>(17,812,765)</u>	26.023%	<u>(4,635,350)</u>
Net Rate Base		414,334,144		107,820,652
Pre-Tax Rate of Return		<u>8.686%</u>		<u>8.686%</u>
Pre-Tax Return on Rate Base		35,989,339		9,365,373
NPC/PTC Benefits	OR	(3,814,062)	100.000%	(3,814,062)
Depreciation				
Wind Generation	SG	19,457,695	26.023%	5,063,404
Transmission	SG	865,794	26.023%	225,302
General	SG	51,546	26.023%	13,414
Deferred Income Tax Expense	SG	156,816	26.023%	40,808
Annual Rev. Reqt. Before Gross-up		52,707,128		10,894,240
Monthly Rev. Reqt. Before Gross-up				<b>907,853</b>
				<b>Ref 8.14.4</b>

		TB Flats Deferral - Year 2		
		Total Company	2021 Allocation %	Oregon Allocated
<b>Revenue Requirement</b>	<b>Factor</b>			
Capital Investment				
Wind Generation	SG	405,463,030	26.023%	105,512,155
Transmission	SG	46,176,918	26.023%	12,016,450
General	SG	1,507,051	26.023%	392,174
Depreciation Reserve				
Wind Generation	SG	(35,687,599)	26.023%	(9,286,853)
Transmission	SG	(1,407,819)	26.023%	(366,352)
General	SG	(83,172)	26.023%	(21,643)
Accumulated DIT Balance	SG	<u>(41,794,183)</u>	26.023%	<u>(10,875,947)</u>
Net Rate Base		374,174,227		97,369,984
Pre-Tax Rate of Return		<u>8.686%</u>		<u>8.686%</u>
Pre-Tax Return on Rate Base		32,501,022		8,457,622
NPC/PTC Benefits*	OR	-	26.023%	-
Depreciation				
Wind Generation	SG	19,613,230	26.023%	5,103,879
Transmission	SG	865,794	26.023%	225,302
General	SG	51,546	26.023%	13,414
Deferred Income Tax Expense	SG	156,816	26.023%	40,808
Annual Rev. Reqt. Before Gross-up		53,188,408		13,841,024
Monthly Rev. Reqt. Before Gross-up				<b>1,153,419</b>
				<b>Ref 8.14.4</b>

\*CY 2022 TAM reflects full NPC/PTC benefit of TB Flats being online - no adjustment required

PacifiCorp  
Oregon General Rate Case - December 2023  
Wind Project Deferrals Amortization  
TB Flats Wind Project Capital Additions  
Deferral Application - UM 2186

In-Service Date Jul-21

**Year 1 - July 2021 through July 2022**

	Gross Plant In Service			Accumulated Depreciation				Depreciation Expense		
	Wind*	Trans.	General	Wind	Trans.	General		Wind	Trans.	General
Jul-21	381,883,656	46,176,918	1,507,051	(6,423,289)	(542,025)	(31,626)	Jul-21	1,477,678	72,150	4,295
Aug-21	386,245,687	46,176,918	1,507,051	(7,971,467)	(614,174)	(35,922)	Aug-21	1,548,178	72,150	4,295
Sep-21	397,900,696	46,176,918	1,507,051	(9,551,928)	(686,324)	(40,217)	Sep-21	1,580,461	72,150	4,295
Oct-21	405,453,030	46,176,918	1,507,051	(11,171,102)	(758,473)	(44,513)	Oct-21	1,619,174	72,150	4,295
Nov-21	405,458,030	46,176,918	1,507,051	(12,805,508)	(830,623)	(48,808)	Nov-21	1,634,406	72,150	4,295
Dec-21	405,463,030	46,176,918	1,507,051	(14,439,933)	(902,772)	(53,104)	Dec-21	1,634,426	72,150	4,295
Jan-22	405,463,030	46,176,918	1,507,051	(16,074,369)	(974,922)	(57,399)	Jan-22	1,634,436	72,150	4,295
Feb-22	405,463,030	46,176,918	1,507,051	(17,708,805)	(1,047,071)	(61,694)	Feb-22	1,634,436	72,150	4,295
Mar-22	405,463,030	46,176,918	1,507,051	(19,343,241)	(1,119,221)	(65,990)	Mar-22	1,634,436	72,150	4,295
Apr-22	405,463,030	46,176,918	1,507,051	(20,977,677)	(1,191,370)	(70,285)	Apr-22	1,634,436	72,150	4,295
May-22	405,463,030	46,176,918	1,507,051	(22,612,112)	(1,263,520)	(74,581)	May-22	1,634,436	72,150	4,295
Jun-22	405,463,030	46,176,918	1,507,051	(24,246,548)	(1,335,669)	(78,876)	Jun-22	1,634,436	72,150	4,295
Jul-22	405,463,030	46,176,918	1,507,051	(25,880,984)	(1,407,819)	(83,172)	Jul-22	1,634,436	72,150	4,295
<b>13 Mo. Avg.</b>	<b>401,588,103</b>	<b>46,176,918</b>	<b>1,507,051</b>	<b>(16,092,843)</b>	<b>(974,922)</b>	<b>(57,399)</b>	<b>12-mo ending</b>	<b>19,457,695</b>	<b>865,794</b>	<b>51,546</b>

Depreciation Rate 4.837% 1.875% 3.420%

**Year 2 - July 2022 through July 2023**

	Gross Plant In Service			Accumulated Depreciation				Depreciation Expense		
	Wind	Trans.	General	Wind	Trans.	General		Wind	Trans.	General
Jul-22	405,463,030	46,176,918	1,507,051	(25,880,984)	(1,407,819)	(83,172)	Jul-22	1,634,436	72,150	4,295
Aug-22	405,463,030	46,176,918	1,507,051	(27,515,420)	(1,407,819)	(83,172)	Aug-22	1,634,436	72,150	4,295
Sep-22	405,463,030	46,176,918	1,507,051	(29,149,856)	(1,407,819)	(83,172)	Sep-22	1,634,436	72,150	4,295
Oct-22	405,463,030	46,176,918	1,507,051	(30,784,291)	(1,407,819)	(83,172)	Oct-22	1,634,436	72,150	4,295
Nov-22	405,463,030	46,176,918	1,507,051	(32,418,727)	(1,407,819)	(83,172)	Nov-22	1,634,436	72,150	4,295
Dec-22	405,463,030	46,176,918	1,507,051	(34,053,163)	(1,407,819)	(83,172)	Dec-22	1,634,436	72,150	4,295
Jan-23	405,463,030	46,176,918	1,507,051	(35,687,599)	(1,407,819)	(83,172)	Jan-23	1,634,436	72,150	4,295
Feb-23	405,463,030	46,176,918	1,507,051	(37,322,035)	(1,407,819)	(83,172)	Feb-23	1,634,436	72,150	4,295
Mar-23	405,463,030	46,176,918	1,507,051	(38,956,470)	(1,407,819)	(83,172)	Mar-23	1,634,436	72,150	4,295
Apr-23	405,463,030	46,176,918	1,507,051	(40,590,906)	(1,407,819)	(83,172)	Apr-23	1,634,436	72,150	4,295
May-23	405,463,030	46,176,918	1,507,051	(42,225,342)	(1,407,819)	(83,172)	May-23	1,634,436	72,150	4,295
Jun-23	405,463,030	46,176,918	1,507,051	(43,859,778)	(1,407,819)	(83,172)	Jun-23	1,634,436	72,150	4,295
Jul-23	405,463,030	46,176,918	1,507,051	(45,494,214)	(1,407,819)	(83,172)	Jul-23	1,634,436	72,150	4,295
<b>13 Mo. Avg.</b>	<b>405,463,030</b>	<b>46,176,918</b>	<b>1,507,051</b>	<b>(35,687,599)</b>	<b>(1,407,819)</b>	<b>(83,172)</b>	<b>12-mo ending</b>	<b>19,613,230</b>	<b>865,794</b>	<b>51,546</b>

\*Gross plant excludes portion of TB Flats that was included in rates effective 1/1/2021

PacifiCorp  
Oregon General Rate Case - December 2023  
Wind Project Deferrals Amortization  
TB Flats Wind Project Tax Balances Summary

In-Service Date Jul-21

Tax: Wind and Transmission	Tax SCHMAT	Tax SCHMDT	Def Inc Tax Exp	Flow-thru	ADIT
Jul-21	1,554,123	(19,340,076)	4,372,961	6,534	(3,035,199)
Aug-21	1,624,623	(19,667,228)	4,436,063	13,068	(7,484,330)
Sep-21	1,656,906	(17,918,977)	3,998,290	13,068	(11,495,689)
Oct-21	1,695,619	(6,210,154)	1,109,971	13,068	(12,618,728)
Nov-21	1,710,851	(6,210,154)	1,106,226	13,068	(13,738,022)
Dec-21	1,710,871	(6,210,154)	1,106,221	13,068	(14,857,311)
Jan-22	1,710,881	(11,003,046)	2,284,627	13,068	(17,155,007)
Feb-22	1,710,881	(11,003,046)	2,284,627	13,068	(19,452,703)
Mar-22	1,710,881	(11,003,046)	2,284,627	13,068	(21,750,399)
Apr-22	1,710,881	(11,003,046)	2,284,627	13,068	(24,048,095)
May-22	1,710,881	(11,003,046)	2,284,627	13,068	(26,345,791)
Jun-22	1,710,881	(11,003,046)	2,284,627	13,068	(28,643,487)
Jul-22	1,710,881	(11,003,046)	2,284,627	13,068	(30,941,183)
<b>12-mo ending</b>	<b>20,375,035</b>	<b>(133,237,989)</b>	<b>27,749,160</b>	<b>156,816</b>	
				<b>13-mo average</b>	<b>(17,812,765)</b>

Tax: Wind and Transmission	Tax SCHMAT	Tax SCHMDT	Def Inc Tax Exp	Flow-thru	ADIT
Jul-22	1,710,881	(11,003,046)	2,284,627	13,068	(30,941,183)
Aug-22	1,710,881	(11,003,046)	2,284,627	13,068	(33,238,879)
Sep-22	1,710,881	(11,003,046)	2,284,627	13,068	(35,536,575)
Oct-22	1,710,881	(11,003,046)	2,284,627	13,068	(37,834,271)
Nov-22	1,710,881	(11,003,046)	2,284,627	13,068	(40,131,967)
Dec-22	1,710,881	(11,003,046)	2,284,627	13,068	(42,429,662)
Jan-23	1,710,881	(6,715,121)	1,230,373	13,068	(43,567,494)
Feb-23	1,710,881	(6,715,121)	1,230,373	13,068	(44,609,939)
Mar-23	1,710,881	(6,715,121)	1,230,373	13,068	(45,546,778)
Apr-23	1,710,881	(6,715,121)	1,230,373	13,068	(46,381,416)
May-23	1,710,881	(6,715,121)	1,230,373	13,068	(47,110,446)
Jun-23	1,710,881	(6,715,121)	1,230,373	13,068	(47,737,276)
Jul-23	1,710,881	(6,715,121)	1,230,373	13,068	(48,258,498)
<b>12-mo ending</b>	<b>20,530,570</b>	<b>(102,021,077)</b>	<b>20,035,746</b>	<b>156,816</b>	
				<b>13-mo average</b>	<b>(41,794,183)</b>

**PacifiCorp**  
**Oregon General Rate Case - December 2021**  
**Wind Project Deferrals Amortization**  
**TB Flats - NPC/PTC Benefits Pro-ration**

	<b><u>TB Flats</u></b>
Actual Online Date	7/27/2021
2021 TAM Online Date	6/30/2021
EV2020 TAM Benefit (TB Flats & Pryor Mountain)	\$ (6,410,832) <sup>1</sup>
TB Flats Proration	69.66%
2021 TAM - Days in Service	185
Daily Benefit in 2021 TAM	\$ (24,140)
Actual Days in Service	158
Benefit Adjustment (Rate Decrease)	\$ (3,814,062)

<b><u>Proration for Rate Update</u></b>	<b><u>Increased MWh<sup>2</sup></u></b>	
Pryor Mountain	132,754,459	30.34%
TB Flats II	304,811,858	69.66%
	<u>437,566,317</u>	<u>100.00%</u>

Footnotes:

- 1 Benefit represents Oregon allocated dollar amount as quantified in 2021 TAM.
- 2 Increased in generation forecasted in TAM with Pryor Mountain & TB Flats II being fully online.  
2021 TAM assumed 6/30/2021 full online date.

**PacifiCorp  
Oregon General Rate Case - December 2023  
Wind Project Deferrals Amortization  
Revenue Requirement Variables**

**Capital Cost and Structure  
From Oregon Results of Operations 12 ME Dec 2018  
Reference UE-369, PAC/404 - Oregon 2020 Renewable Adjustment Clause**

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	47.89%	5.27%	2.525%		2.525%
Preferred	0.02%	6.75%	0.001%	132.60%	0.002%
Common	52.09%	9.80%	5.105%	132.60%	6.769%
Total	100.00%		7.631%		9.296%

Merged Effective Tax Rate 24.587%  
Tax Gross-up factor for PTC =  $(1/(1 - \text{tax rate}))$  132.60%

**2017 Protocol Allocation Factors**

Forecast 2020 SG Factor <sup>1</sup> 26.4558%  
Oregon GPS Factor <sup>2</sup> 27.3374%

**Property Tax Calculation**

Total Company 151,139,518  
Oregon GPS Factor <sup>2</sup> 27.3374%  
Oregon Property Taxes 41,317,669

Oregon Gross EPIS 7,699,300,653  
Oregon Accum. Depr. (2,979,098,163)  
Oregon Accum. Amort. (171,186,979)  
Oregon Net EPIS 4,549,015,511

Estimated Oregon Property Tax Rate 0.908%

Footnotes:

- 1 SG Factor from 2020 TAM filing
- 2 Results of Operations, December 2018, Page 9.2
- 3 Oregon General Rate Case Docket No. UE 374 Compliance Filing Jurisdictional Allocation Model (JAM)

**Capital Cost and Structure  
Ordered from Oregon 2021 General Rate Case  
Reference UE-374, Compliance Filing**

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	49.99%	4.77%	2.387%		2.387%
Preferred	0.01%	6.75%	0.001%	1.326	0.001%
Common	50.00%	9.50%	4.750%	1.326	6.299%
TOTAL			7.137%		8.686%

Merged Effective Tax Rate 24.587%  
Tax Gross-up factor for PTC =  $(1/(1 - \text{tax rate}))$  132.60%

**2020 Protocol Allocation Factors**

Approved 2021 SG Factor <sup>3</sup> 26.0226%

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Miscellaneous Rate Base**

<b>Adjustment to Rate Base:</b>	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
1 - Fuel Stock - Pro Forma	151	3	(29,210,086)	SE	25.068%	(7,322,424)	8.15.1
1 - Fuel Stock - Working Capital Deposit	25316	3	3,000	SE	25.068%	752	8.15.1
1 - Fuel Stock - Working Capital Deposit	25317	3	34,169	SE	25.068%	8,566	8.15.1
2 - Prepaid Overhauls	186M	3	(16,949,013)	SG	26.070%	(4,418,666)	8.15.1

**Description of Adjustment:**

- 1 - Fuel stock levels for the 13 month average year ending December 2023 are projected to be lower than the year ended June 2021 levels due to an increase in the amount of coal stockpiled. The adjustment also reflects the change in projected working capital deposits.
- 2 - Balances for prepaid overhauls at the Lake Side, Chehalis and Currant Creek gas plants are walked forward to reflect payments and transfers of capital to electric plant in service during the year ending December 2023.



**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Miscellaneous Rate Base**

			Actuals	Pro Forma	
			Jun-2021 EOP Balance	Dec-2023 13 Mth. Avg. Balance	Adj. to 13 Mth. Avg. Balance
<b>1 - Coal Fuel Stock Balances by Plant</b>	<b>Account</b>	<b>Factor</b>			
Jim Bridger	151	SE	34,164,407	47,165,373	13,000,966
Cholla	151	SE	(0)	(0)	-
Colstrip	151	SE	1,907,941	2,019,347	111,406
Craig	151	SE	611,228	3,609,917	2,998,689
Hayden	151	SE	4,236,263	1,946,527	(2,289,736)
Hunter	151	SE	71,160,227	47,584,144	(23,576,084)
Huntington	151	SE	23,856,872	20,802,902	(3,053,970)
Dave Johnston	151	SE	11,802,796	9,993,677	(1,809,119)
Naughton	151	SE	24,588,118	9,995,879	(14,592,238)
Rock Garden	151	SE	31,430,017	31,430,017	-
<b>Total</b>			<b>203,757,869</b>	<b>174,547,782</b>	<b>(29,210,086)</b>

Ref. 8.15

			Actuals	Pro Forma	
			Jun-2021 EOP Balance	Dec-2023 13 Mth. Avg. Balance	Adj. to 13 Mth. Avg. Balance
<b>1 - Working Capital Deposits</b>	<b>Account</b>	<b>Factor</b>			
UAMPS Working Capital Deposit	25316	SE	(2,806,000)	(2,803,000)	3,000
DPEC Working Capital Deposit	25317	SE	(2,675,522)	(2,641,353)	34,169

Ref. 8.15

Ref. 8.15

			Actuals	Pro Forma	
			Jun-2021 EOP Balance	Dec-2023 13 Mth. Avg. Balance	Adj. to 13 Mth. Avg. Balance
<b>2 - Overhaul Prepayments by Plant</b>	<b>Account</b>	<b>Factor</b>			
Lake Side 1	186M	SG	11,807,302	22,057,381	10,250,079
Chehalis	186M	SG	23,922,978	10,749,897	(13,173,081)
Currant Creek	186M	SG	23,241,474	9,204,028	(14,037,446)
Lake Side 2	186M	SG	21,225,077	20,767,776	(457,302)
Chehalis O&M	186M	SG	1,114,407	1,144,899	30,492
Currant Creek O&M	186M	SG	-	438,245	438,245
<b>Total</b>			<b>81,311,238</b>	<b>64,362,225</b>	<b>(16,949,013)</b>

Ref. 8.15

**PacifiCorp  
Oregon General Rate Case - December 2023  
Carbon Plant Closure**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Expense:</b>							
Remove system alloc deferral	403SP	1	(11,539,055)	SG	26.070%	(3,008,271)	8.16.1
Excess decommissioning costs amort.	407	3	(1,705,494)	OR	Situs	(1,705,494)	8.16.2
<b>Adjustment to Rate Base:</b>							
Remove M&S Obsolete Inventory	182M	1	(3,448,669)	SG	26.070%	(899,080)	8.16.2
Remove M&S Obsolete Inventory	182M	1	89,744	OR	Situs	89,744	B-16
Excess decommissioning reserves	254	3	(4,039,377)	OR	Situs	(4,039,377)	8.16.2
<b>Adjustment to Tax:</b>							
Schedule M - Excess Decommissioning	SCHMDT	3	1,705,494	OR	Situs	1,705,494	
Deferred Income Tax Expense	41010	3	419,323	OR	Situs	419,323	
Accumulated Def Inc Tax Balance	190	3	993,141	OR	Situs	993,141	
Accumulated Def Inc Tax Balance	283	1	452,791	SG	26.070%	118,044	

**Description of Adjustment:**

The Carbon Plant was retired April, 2015 and fully recovered as of December 2020. This adjustment removes the allocation in the base period of accelerated depreciation deferral and amortization and returns excess decommissioning costs of the plant back to ratepayers over a five-year period per the proposal in the Company's 2018 Deprecation Study, UM 1968. 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.

**PacifiCorp  
Oregon General Rate Case - December 2023  
Carbon Plant Closure**

On January 1, 2014 new depreciation rates for the Carbon Plant became effective in Utah, Idaho, and Wyoming. The difference in the depreciation in these rates due to the retirement of the Carbon Plant was deferred in those states, to be amortized to expense after the plant was retired. This deferral and amortization of depreciation expense was booked on a company system factor. It should have been allocated situs to Utah, Idaho, and Wyoming, as appropriate. The accounting detail is provided below.

Year	Posting period	Account Number	Amount	Text	FERC Account	FERC Location	Actual Allocation
2020	7	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2020	7	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2020	7	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2020	7	565131	37,209	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2020	8	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2020	8	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2020	8	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2020	8	565131	37,209	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2020	9	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2020	9	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2020	9	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2020	9	565131	37,209	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2020	10	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2020	10	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2020	10	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2020	10	565131	37,209	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2020	11	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2020	11	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2020	11	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2020	11	565131	37,209	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2020	12	565131	37,209	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2020	12	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2020	12	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2020	12	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2020	12	565131	8,775,068	Buy down Utah deferred decomm	4032000	109	SG
			<u>11,539,055</u>				

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**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. UE374, in Order 20-473.

Closure Cost	Total Company	*Allocation	OR Allocated
M&S Obsolete Inventory	3,448,669	26.023%	897,435
Decommissioning Reserve			<u>(8,976,188)</u>
Total Closure Cost			(8,078,754)

\*Allocation on approved SG factor from UE-374 OR GRC

Tax Impacts:

Date	Beg Bal	Amortization	End Bal	Date	Beg Bal	Amortization	End Bal	SCHMDT	41010	ADIT - 190	
Dec-20			(8,976,188)	Dec-20			897,435			1,986,291	
Jan-21	(8,976,188)	149,603	(8,826,585)	Jan-21	897,435	(14,957)	882,477	134,646	33,105	1,953,186	
Feb-21	(8,826,585)	149,603	(8,676,982)	Feb-21	882,477	(14,957)	867,520	134,646	33,105	1,920,081	
Mar-21	(8,676,982)	149,603	(8,527,379)	Mar-21	867,520	(14,957)	852,563	134,646	33,105	1,886,976	
Apr-21	(8,527,379)	149,603	(8,377,776)	Apr-21	852,563	(14,957)	837,606	134,646	33,105	1,853,871	
May-21	(8,377,776)	149,603	(8,228,173)	May-21	837,606	(14,957)	822,648	134,646	33,105	1,820,766	
Jun-21	(8,228,173)	149,603	(8,078,569)	Jun-21	822,648	(14,957)	807,691	134,646	33,105	1,787,661	
Jul-21	(8,078,569)	149,603	(7,928,966)	Jul-21	807,691	(14,957)	792,734	134,646	33,105	1,754,556	
Aug-21	(7,928,966)	149,603	(7,779,363)	Aug-21	792,734	(14,957)	777,777	134,646	33,105	1,721,451	
Sep-21	(7,779,363)	149,603	(7,629,760)	Sep-21	777,777	(14,957)	762,819	134,646	33,105	1,688,346	
Oct-21	(7,629,760)	149,603	(7,480,157)	Oct-21	762,819	(14,957)	747,862	134,646	33,105	1,655,241	
Nov-21	(7,480,157)	149,603	(7,330,554)	Nov-21	747,862	(14,957)	732,905	134,646	33,105	1,622,136	
Dec-21	(7,330,554)	149,603	(7,180,951)	Dec-21	732,905	(14,957)	717,948	134,646	33,105	1,589,031	
Jan-22	(7,180,951)	149,603	(7,031,347)	Jan-22	717,948	(14,957)	702,990	134,646	33,105	1,555,926	
Feb-22	(7,031,347)	149,603	(6,881,744)	Feb-22	702,990	(14,957)	688,033	134,646	33,105	1,522,821	
Mar-22	(6,881,744)	149,603	(6,732,141)	Mar-22	688,033	(14,957)	673,076	134,646	33,105	1,489,716	
Apr-22	(6,732,141)	149,603	(6,582,538)	Apr-22	673,076	(14,957)	658,119	134,646	33,105	1,456,611	
May-22	(6,582,538)	149,603	(6,432,935)	May-22	658,119	(14,957)	643,161	134,646	33,105	1,423,506	
Jun-22	(6,432,935)	149,603	(6,283,332)	Jun-22	643,161	(14,957)	628,204	134,646	33,105	1,390,401	
Jul-22	(6,283,332)	149,603	(6,133,729)	Jul-22	628,204	(14,957)	613,247	134,646	33,105	1,357,296	
Aug-22	(6,133,729)	149,603	(5,984,125)	Aug-22	613,247	(14,957)	598,290	134,646	33,105	1,324,191	
Sep-22	(5,984,125)	149,603	(5,834,522)	Sep-22	598,290	(14,957)	583,332	134,646	33,105	1,291,086	
Oct-22	(5,834,522)	149,603	(5,684,919)	Oct-22	583,332	(14,957)	568,375	134,646	33,105	1,257,981	
Nov-22	(5,684,919)	149,603	(5,535,316)	Nov-22	568,375	(14,957)	553,418	134,646	33,105	1,224,876	
Dec-22	(5,535,316)	149,603	(5,385,713)	Dec-22	553,418	(14,957)	538,461	134,646	33,105	1,191,771	
Jan-23	(5,385,713)	149,603	(5,236,110)	Jan-23	538,461	(14,957)	523,503	134,646	33,105	1,158,666	
Feb-23	(5,236,110)	149,603	(5,086,507)	Feb-23	523,503	(14,957)	508,546	134,646	33,105	1,125,561	
Mar-23	(5,086,507)	149,603	(4,936,904)	Mar-23	508,546	(14,957)	493,589	134,646	33,105	1,092,456	
Apr-23	(4,936,904)	149,603	(4,787,300)	Apr-23	493,589	(14,957)	478,632	134,646	33,105	1,059,351	
May-23	(4,787,300)	149,603	(4,637,697)	May-23	478,632	(14,957)	463,675	134,646	33,105	1,026,246	
Jun-23	(4,637,697)	149,603	(4,488,094)	Jun-23	463,675	(14,957)	448,717	134,646	33,105	993,141	
Jul-23	(4,488,094)	149,603	(4,338,491)	Jul-23	448,717	(14,957)	433,760	134,646	33,105	960,036	
Aug-23	(4,338,491)	149,603	(4,188,888)	Aug-23	433,760	(14,957)	418,803	134,646	33,105	926,931	
Sep-23	(4,188,888)	149,603	(4,039,285)	Sep-23	418,803	(14,957)	403,846	134,646	33,105	893,826	
Oct-23	(4,039,285)	149,603	(3,889,682)	Oct-23	403,846	(14,957)	388,888	134,646	33,105	860,721	
Nov-23	(3,889,682)	149,603	(3,740,078)	Nov-23	388,888	(14,957)	373,931	134,646	33,105	827,616	
Dec-23	(3,740,078)	149,603	(3,590,475)	Dec-23	373,931	(14,957)	358,974	134,646	33,105	794,511	
<b>Amort exp. 12 months ending Dec. 2023</b>			<b>1,795,238 below</b>	<b>Amort exp. 12 months ending Dec. 2023</b>			<b>(179,487) below</b>				
Net Rate Base Reduction			<b>(4,039,377)</b>	Ref 8.16							
12 ME June-21 Amort. Exp			<b>89,744</b>								
12 ME Dec-23 Amort. Exp.			<b>1,615,751</b>	above							
Adjustment			<b>1,705,494</b>	Ref 8.16							

	ADIT		
	13MA Bal.	SCHMDT	41010
	993,141	1,705,494	(419,323)
	Ref. 8.16	Ref. 8.16	Ref. 8.16

Exhibit PAC/1002  
Cheung/288

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Remove Labor Day Wildfire Restoration**

	<u>ACCOUNT</u>	<u>Type</u>	<u>TOTAL</u> <u>COMPANY</u>	<u>FACTOR</u>	<u>FACTOR %</u>	<u>OREGON</u> <u>ALLOCATED</u>	<u>REF#</u>
<b>Adjustment to Rate Base:</b>							
Transmission Plant	355	1	(89,852,182)	SG	26.070%	(23,424,771)	
Distribution Plant	360	1	(430,798)	OR	Situs	(352,322)	
Distribution Plant	361	1	(816,620)	OR	Situs	(667,862)	
Distribution Plant	362	1	(6,775,813)	OR	Situs	(5,541,509)	
Distribution Plant	364	1	(8,855,242)	OR	Situs	(7,242,143)	
Distribution Plant	365	1	(5,572,291)	OR	Situs	(4,557,225)	
Distribution Plant	366	1	(2,764,594)	OR	Situs	(2,260,987)	
Distribution Plant	367	1	(6,449,237)	OR	Situs	(5,274,424)	
Distribution Plant	368	1	(9,762,008)	OR	Situs	(7,983,730)	
Distribution Plant	369	1	(6,036,591)	OR	Situs	(4,936,946)	
Distribution Plant	370	1	(1,652,422)	OR	Situs	(1,351,412)	
Distribution Plant	371	1	(57,132)	OR	Situs	(46,725)	
Distribution Plant	373	1	(409,154)	OR	Situs	(334,621)	
			<u>(139,434,083)</u>			<u>(63,974,678)</u>	8.17.1
<b>Adjustment to Depreciation Reserve:</b>							
Transmission Plant	108TP	1	755,195	SG	26.070%	196,882	
Distribution Plant	108360	1	6,591	OR	Situs	5,261	
Distribution Plant	108361	1	12,495	OR	Situs	9,972	
Distribution Plant	108362	1	103,673	OR	Situs	82,743	
Distribution Plant	108364	1	135,489	OR	Situs	108,135	
Distribution Plant	108365	1	85,258	OR	Situs	68,046	
Distribution Plant	108366	1	42,299	OR	Situs	33,760	
Distribution Plant	108367	1	98,676	OR	Situs	78,755	
Distribution Plant	108368	1	149,363	OR	Situs	119,208	
Distribution Plant	108369	1	92,362	OR	Situs	73,716	
Distribution Plant	108370	1	25,283	OR	Situs	20,178	
Distribution Plant	108371	1	874	OR	Situs	698	
Distribution Plant	108373	1	6,260	OR	Situs	4,996	
			<u>1,513,819</u>			<u>802,349</u>	8.17.1
<b>Adjustment to Tax:</b>							
Schedule M Deduction - SG - Tax Depr	SCHMDT	1	(8,535,960)	SG	26.070%	(2,225,354)	
Schedule M Deduction - OR - Tax Depr	SCHMDT	1	(2,927,292)	OR	Situs	(2,927,292)	
Schedule M Deduction - CA - Tax Depr	SCHMDT	1	(652,020)	CA	Situs	-	
			<u>(12,115,272)</u>			<u>(5,152,646)</u>	
Deferred Inc Tax Exp - SG - Tax Depr	41010	1	(2,098,702)	SG	26.070%	(547,139)	
Deferred Inc Tax Exp - OR - Tax Depr	41010	1	(719,722)	OR	Situs	(719,722)	
Deferred Inc Tax Exp - CA - Tax Depr	41010	1	(160,310)	CA	Situs	-	
			<u>(2,978,734)</u>			<u>(1,266,861)</u>	
ADIT - SG	282	1	2,632,090	SG	26.070%	686,195	
ADIT - OR	282	1	753,915	OR	Situs	753,915	
ADIT - CA	282	1	153,510	CA	Situs	-	
			<u>3,539,515</u>			<u>1,440,110</u>	

**Description of Adjustment:**

This adjustment removes the capital additions from the Base Period 12 months ended June 2021 for the Labor Day Wildfire Restoration capital projects. Correspondingly, these projects are also excluded from the depreciation normalizing calculations in Adjustment 6.1.

**PacifiCorp**  
**Oregon General Rate Case - December 2023**  
**Remove Labor Day Wildfire Restoration**  
**Base Period Capital Project Balances**

**Capital Placed In-Service - EOP June 2021**

<b>Project</b>	<b>State</b>	<b>Function</b>	<b>Factor</b>	<b>EOP Jun-21</b>
Archie Creek Fire Damage Repair	OR	Distribution	OR	13,737,335
Archie Creek Fire Damage Repair	OR	Transmission	SG	27,270,264
Slater Fire (Happy Camp) Fire Damage	CA	Distribution	CA	9,031,995
Slater Fire (Happy Camp) Fire Damage	OR	Distribution	OR	2,048,231
Slater Fire (Happy Camp) Fire Damage	CA	Transmission	SG	39,742,224
Slater Fire (Happy Camp) Fire Damage	OR	Transmission	SG	1,021,952
Almeda Fire Damage Repair	OR	Distribution	OR	5,827,614
Almeda Fire Damage Repair	OR	General	SO	-
Almeda Fire Damage Repair	OR	Transmission	SG	970,516
Beachie Creek Fire Damage Repair	OR	Distribution	OR	2,520,677
Two Four Two Fire Damage Repair	OR	Transmission	SG	16,054
Two Four Two Fire Damage Repair	OR	Distribution	OR	6,260,467
S. Obenchain Fire Damage Repair	OR	Transmission	SG	70,242
S. Obenchain Fire Damage Repair	OR	Distribution	OR	503,891
Echo Mountain Fire Damage Repair	OR	Distribution	OR	9,651,692
Echo Mountain Fire Damage Repair	OR	Transmission	SG	20,760,931
<b>Total</b>				<b>139,434,083</b>

**Ref 8.17**

**Accumulated Depreciation Reseve**

<b>Project</b>	<b>State</b>	<b>Function</b>	<b>Factor</b>	<b>EOP Jun-21</b>
Archie Creek Fire Damage Repair	OR	Distribution	OR	(233,903)
Archie Creek Fire Damage Repair	OR	Transmission	SG	(282,887)
Slater Fire (Happy Camp) Fire Damage	CA	Distribution	CA	(153,156)
Slater Fire (Happy Camp) Fire Damage	OR	Distribution	OR	(8,657)
Slater Fire (Happy Camp) Fire Damage	CA	Transmission	SG	(430,809)
Slater Fire (Happy Camp) Fire Damage	OR	Transmission	SG	(6,274)
Almeda Fire Damage Repair	OR	Distribution	OR	(66,189)
Almeda Fire Damage Repair	OR	General	SO	-
Almeda Fire Damage Repair	OR	Transmission	SG	(10,666)
Beachie Creek Fire Damage Repair	OR	Distribution	OR	(46,608)
Two Four Two Fire Damage Repair	OR	Transmission	SG	(133)
Two Four Two Fire Damage Repair	OR	Distribution	OR	(112,789)
S. Obenchain Fire Damage Repair	OR	Transmission	SG	(1,446)
S. Obenchain Fire Damage Repair	OR	Distribution	OR	(6,863)
Echo Mountain Fire Damage Repair	OR	Distribution	OR	(130,460)
Echo Mountain Fire Damage Repair	OR	Transmission	SG	(22,980)
<b>Total</b>				<b>(1,513,819)</b>

**Ref 8.17**

Tab +- 6k` S\_ [U756

**OREGON**  
**ANNUAL EMBEDDED COSTS**  
**Twelve Months Ending December 31, 2023**  
**YEAR END BALANCE**

**Company Owned Hydro - West**

Account	Description	Amount	Mwh	\$/Mwh	Differential
535 - 545	Hydro Operation & Maintenance Expense	35,671,725			
403HP	Hydro Depreciation Expense	24,769,019			
404IP / 404HP	Hydro Relicensing Amortization	3,070,608			
	<b>Total West Hydro Operating Expense</b>	<b>63,511,353</b>			
330 - 336	Hydro Electric Plant in Service	1,011,178,647			
302 & 182M	Hydro Relicensing	177,482,844			
108HP	Hydro Accumulated Depreciation Reserve	(432,579,140)			
111IP	Hydro Relicensing Accumulated Reserve	(118,482,024)			
154	Materials and Supplies	7,954			
	<b>West Hydro Net Rate Base</b>	<b>637,608,281</b>			
	Pre-tax Return	8.88%			
	<b>Rate Base Revenue Requirement</b>	<b>56,631,184</b>			
	<b>Annual Embedded Cost</b>				
	<b>West Hydro-Electric Resources</b>	<b>120,142,537</b>	3,261,314	36.84	(44,885,867)

**Mid C Contracts**

Account	Description	Amount	Mwh	\$/Mwh	Differential
555	Annual Mid-C Contracts Costs	2,265,569	93,452	24.24	(2,463,291)
	Grant Reasonable Portion	-			-
		2,265,569			(2,463,291)

**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				
	<b>Total Qualified Facilities Costs</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>

**All Other Generation Resources**  
(Excl. West Hydro, Mid C, and QF)

Account	Description	Amount	Mwh	\$/Mwh	Differential
500 - 514	Steam Operation & Maintenance Expense	934,375,741			
535 - 545	East Hydro Operation & Maintenance Expense	10,657,563			
546 - 554	Other Generation Operation & Maintenance Expense	50,781,968			
555	Other Purchased Power Contracts	0			
40910	Production Tax Credit	0			
4118	SO2 Emission Allowances	(47)			
456	James River / Little Mountain Offset	0			
456	REC Revenues	0			
403SP	Steam Depreciation Expense	275,464,212			
403HP	East Hydro Depreciation Expense	10,129,580			
403OP	Other Generation Depreciation Expense	12,052,676			
403MP	Mining Depreciation Expense	0			
404IP	East Hydro Relicensing Amortization	328,490			
406	Amortization of Plant Acquisition Costs	0			
	<b>Total All Other Operating Expenses</b>	<b>1,293,790,182</b>			
310 - 316	Steam Electric Plant in Service	6,873,501,850			
330 - 336	East Hydro Electric Plant in Service	222,560,115			
302 & 186M	East Hydro Relicensing	10,223,926			
340 - 346	Other Electric Plant in Service	269,160,334			
399	Mining	50,741,701			
108SP	Steam Accumulated Depreciation Reserve	(4,673,052,979)			
108OP	Other Generation Accumulated Depreciation Reserve	(142,858,162)			
108MP	Other Accumulated Depreciation Reserve	0			
108HP	East Hydro Accumulated Depreciation Reserve	(105,983,333)			
111IP	East Hydro Relicensing Accumulated Reserve	(6,359,021)			
114	Electric Plant Acquisition Adjustment	141,186,242			
115	Accumulated Provision Acquisition Adjustment	(137,303,921)			
151	Fuel Stock	176,033,332			
253.16 - 253.19	Joint Owner WC Deposit	(5,717,354)			
253.98	SO2 Emission Allowances	0			
154	Materials & Supplies	85,247,211			
154	East Hydro Materials & Supplies				
	<b>Total Net Rate Base</b>	<b>2,757,379,941</b>			
	Pre-tax Return	8.88%			
	<b>Rate Base Revenue Requirement</b>	<b>244,905,370</b>			
	<b>Annual Embedded Cost</b>				
	<b>All Other Generation Resources</b>	<b>1,538,695,552</b>	30,407,910	50.60	
	<b>Total Annual Embedded Costs</b>	<b>1,661,103,658</b>	<b>33,762,676</b>	<b>49.20</b>	



## Tab 10 - 2020 Protocol Factors

**OREGON GENERAL RATE CASE**  
**Pro Forma Factors December 31, 2023**

DESCRIPTION	2020 PROTOCOL FACTOR	2020 PROTOCOL										Page Ref.
		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY		
Situs	S	-	-	-	-	-	-	-	-	-	-	Situs
System Generation	SG	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	0.0000%	0.0000%	0.0000%	Pg 10.16
Divisional Generation - Pac. Power	DGP	3.1128%	55.3072%	16.6300%	0.0000%	0.0000%	24.9499%	0.0000%	0.0000%	0.0000%	0.0000%	Pg 10.16
Divisional Generation - R.M.P.	DGU	0.0000%	0.0000%	0.0000%	83.9816%	11.3613%	4.6017%	0.0554%	0.0000%	0.0000%	0.0000%	Pg 10.16
System Capacity	SC	1.4853%	26.4044%	7.9926%	44.4439%	5.8665%	13.7796%	0.0277%	0.0000%	0.0000%	0.0000%	Pg 10.16
System Energy	SE	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	0.0000%	0.0000%	0.0000%	Pg 10.16
System Overhead	SO	2.2051%	27.1731%	7.6767%	43.9355%	5.8423%	13.1469%	0.0206%	0.0000%	0.0000%	0.0000%	Pg 10.7
Gross Plant-System	GPS	2.2051%	27.1731%	7.6767%	43.9355%	5.8423%	13.1469%	0.0206%	0.0000%	0.0000%	0.0000%	Pg 10.6
System Net Plant	SNP	2.0832%	25.5986%	7.4574%	45.7605%	5.9211%	13.1477%	0.0210%	0.0106%	0.0000%	0.0000%	Pg 10.6
Division Net Plant Distribution	SNPD	3.5402%	26.4726%	6.3941%	48.6788%	5.3128%	9.6014%	0.0000%	0.0000%	0.0000%	0.0000%	Pg 10.5
Customer - System	CN	2.3440%	30.9899%	6.8442%	48.2980%	4.2426%	7.2812%	0.0000%	0.0000%	0.0000%	0.0000%	Pg 10.10
CIAC	CIAC	3.5402%	26.4726%	6.3941%	48.6788%	5.3128%	9.6014%	0.0000%	0.0000%	0.0000%	0.0000%	Pg 10.10
Bad Debt Expense	BADDEBT	2.0425%	48.4851%	14.7131%	28.6331%	5.3944%	0.7318%	0.0000%	0.0000%	0.0000%	0.0000%	Pg 10.9
Accumulated Investment Tax Credit 1984	ITC84	3.2870%	70.9760%	14.1800%	0.0000%	0.0000%	10.9460%	0.0000%	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%	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%	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%	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%	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%	0.0000%	0.3860%	Fixed
Other Electric	OTHER	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	Situs
Non-Utility	NUTIL	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	Situs
System Net Steam Plant	SNPPS	1.4737%	26.1849%	7.7872%	44.1781%	6.0909%	14.2557%	0.0294%	0.0000%	0.0000%	0.0000%	Pg 10.3
System Net Transmission Plant	SNPT	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	0.0000%	0.0000%	0.0000%	Pg 10.4
System Net Production Plant	SNPP	1.5045%	24.2823%	8.0141%	45.4126%	6.1746%	14.5537%	0.0300%	0.0282%	0.0000%	0.0000%	Pg 10.4
System Net Hydro Plant	SNPPH	1.4628%	25.9912%	7.8152%	44.2602%	5.9877%	14.1503%	0.0292%	0.3034%	0.0000%	0.0000%	Pg 10.3
System Net Other Production Plant	SNPPO	1.5243%	23.1918%	8.1434%	46.1265%	6.2391%	14.7445%	0.0304%	0.0000%	0.0000%	0.0000%	Pg 10.4
System Net General Plant	SNPG	2.6778%	28.0469%	6.3177%	41.8563%	6.5308%	14.5586%	0.0120%	0.0000%	0.0000%	0.0000%	Pg 10.5
System Net Intangible Plant	SNPI	1.8850%	26.6419%	7.7896%	43.5059%	6.3827%	13.7735%	0.0214%	0.0000%	0.0000%	0.0000%	Pg 10.6
Trojan Plant Allocator	TROJP	1.4591%	25.9181%	7.7689%	44.3726%	6.0694%	14.3819%	0.0300%	0.0000%	0.0000%	0.0000%	Pg 10.12
Trojan Decommissioning Allocator	TROJD	1.4576%	25.8912%	7.7566%	44.3687%	6.0806%	14.4152%	0.0301%	0.0000%	0.0000%	0.0000%	Pg 10.12
DIT Balance	DITBAL	2.1884%	24.5033%	6.1527%	44.6300%	5.9154%	14.5882%	0.2075%	0.0000%	0.0000%	1.8144%	Pg 10.9
Tax Depreciation	TAXDEPR	1.9019%	26.4097%	4.4419%	44.9600%	5.8445%	13.2875%	0.0237%	0.0000%	0.0000%	3.1308%	Pg 10.13
SCHMAT Depreciation Expense	SCHMDEXP	1.7753%	22.6477%	6.6681%	37.9597%	5.0550%	11.6599%	0.0197%	14.2146%	0.0000%	0.0000%	Pg 10.12
System Generation Cholla Transaction	SGCT	1.4677%	26.0780%	7.8412%	44.4079%	6.0077%	14.1975%	0.0000%	0.0000%	0.0000%	0.0000%	Pg 10.2

**CALCULATION OF INTERNAL FACTORS**  
**Pro Forma Factors December 31, 2023**

DESCRIPTION OF FACTOR	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
<b>STEAM :</b>										
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	6,945,577,158	101,912,184	1,810,735,721	544,460,031	3,083,484,225	417,144,788	985,807,771	2,032,437	0	0

OREGON GENERAL RATE CASE  
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
		0	0	0	0	0	0	0	0	0	0
SSGCH		6,945,577,158	101,912,184	1,810,735,721	544,460,031	3,083,484,225	417,144,788	985,807,771	2,032,437	0	0
LESS ACCUMULATED DEPRECIATION											
S		(9,098,547)	0	0	(1,784,808)	(8,526,815)	1,213,075	0	0	0	0
DGP		(749,221,847)	(10,993,303)	(195,324,698)	(58,731,095)	(332,616,526)	(44,997,555)	-106,339,430	(219,240)	0	0
DGU		(719,880,716)	(10,562,782)	(187,675,365)	(56,431,059)	(319,590,551)	(43,235,354)	-102,174,951	(210,654)	0	0
SG		(3,397,616,381)	(49,853,093)	(885,770,211)	(266,337,307)	(1,508,369,467)	(204,057,623)	-482,234,457	(994,222)	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
		(4,875,817,492)	(71,409,178)	(1,268,770,274)	(383,284,269)	(2,169,103,359)	(291,077,457)	(690,748,839)	(1,424,115)	0	0
TOTAL NET STEAM PLANT		2,069,759,666	30,503,006	541,965,446	161,175,761	914,380,866	126,067,331	295,058,932	608,322	0	0
SNPPS											
SYSTEM NET PLANT PRODUCTION STEAM		100.0000%	1.4737%	26.1849%	7.7872%	44.1781%	6.0909%	14.2557%	0.0294%	0.0000%	0.0000%
<b>NUCLEAR :</b>		<b>TOTAL</b>	<b>California</b>	<b>Oregon</b>	<b>Washington</b>	<b>Utah</b>	<b>Idaho</b>	<b>Wyoming</b>	<b>FERC</b>		
NUCLEAR PRODUCTION PLANT											
DGP		0	0	0	0	0	0	0	0		
DGU		0	0	0	0	0	0	0	0		
SG		0	0	0	0	0	0	0	0		
		0	0	0	0	0	0	0	0		
LESS ACCUMULATED DEPRECIATION											
DGP		0	0	0	0	0	0	0	0		
DGU		0	0	0	0	0	0	0	0		
SG		0	0	0	0	0	0	0	0		
		0	0	0	0	0	0	0	0		
TOTAL NUCLEAR PLANT		0	0	0	0	0	0	0	0		
SNPPN											
SYSTEM NET PLANT PRODUCTION NUCLEAR		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%		
<b>HYDRO :</b>		<b>TOTAL</b>	<b>California</b>	<b>Oregon</b>	<b>Washington</b>	<b>Utah</b>	<b>Idaho</b>	<b>Wyoming</b>	<b>FERC</b>	<b>Other</b>	<b>Non-Utility</b>
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		1,233,738,762	18,102,601	321,639,915	96,712,113	547,717,479	74,097,182	175,108,451	361,021	0	0
		1,233,738,762	18,102,601	321,639,915	96,712,113	547,717,479	74,097,182	175,108,451	361,021	0	0
LESS ACCUMULATED DEPRECIATION (incl hydro amortization)											
S		2,104,465	0	0	0	0	0	0	0	2,104,465	0
DGP		(169,356,335)	(2,484,959)	(44,151,776)	(13,275,751)	(75,185,629)	(10,171,381)	(24,037,281)	(49,558)	0	0
DGU		(31,496,322)	(462,144)	(8,211,199)	(2,468,980)	(13,982,771)	(1,891,639)	(4,470,373)	(9,217)	0	0
SG		(341,316,594)	(5,008,125)	(88,982,403)	(26,755,623)	(151,527,268)	(20,499,151)	(48,444,146)	(99,877)	0	0
		(540,064,787)	(7,955,228)	(141,345,378)	(42,500,354)	(240,695,668)	(32,562,172)	(76,951,800)	(158,651)	2,104,465	0
TOTAL NET HYDRO PRODUCTION PLANT		693,673,975	10,147,373	180,294,537	54,211,759	307,021,811	41,535,010	98,156,652	202,369	2,104,465	0
SNPPH											
SYSTEM NET PLANT PRODUCTION HYDRO		100.0000%	1.4628%	25.9912%	7.8152%	44.2602%	5.9877%	14.1503%	0.0292%	0.3034%	0.0000%
<b>OTHER :</b>		<b>TOTAL</b>	<b>California</b>	<b>Oregon</b>	<b>Washington</b>	<b>Utah</b>	<b>Idaho</b>	<b>Wyoming</b>	<b>FERC</b>	<b>Other</b>	<b>Non-Utility</b>
OTHER PRODUCTION PLANT (EXCLUDES EXPERIMENTAL)											

OREGON GENERAL RATE CASE  
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR	2020 PROTOCOL FACTOR									Page Ref.
		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	
S	748,763	0	390,301	0	358,462	0	0	0	0	0	0
DGP & DGU	0	0	0	0	0	0	0	0	0	0	0
SG	5,292,321,711	77,654,031	1,379,726,371	414,862,232	2,349,522,601	317,851,831	751,155,988	1,548,656	0	0	0
SSGCT	0	0	0	0	0	0	0	0	0	0	0
	5,293,070,474	77,654,031	1,380,116,672	414,862,232	2,349,881,063	317,851,831	751,155,988	1,548,656	0	0	0
LESS ACCUMULATED DEPRECIATION											
S	(183,200,250)	0	(183,195,467)	0	(4,783)	0	0	0	0	0	0
DGP	202,224,324	2,967,230	52,720,573	15,852,255	89,777,350	12,145,401	28,702,339	59,176	0	0	0
DGU	0	0	0	0	0	0	0	0	0	0	0
SG	(570,089,603)	(8,364,903)	(148,624,309)	(44,689,015)	(253,090,889)	(34,239,042)	(80,914,623)	(166,821)	0	0	0
SSGCT	(43,837,829)	(643,231)	(11,428,672)	(3,436,424)	(19,461,774)	(2,632,859)	(6,222,042)	(12,828)	0	0	0
	(594,903,358)	(6,040,904)	(290,527,875)	(32,273,184)	(182,780,096)	(24,726,499)	(58,434,326)	(120,474)	0	0	0
TOTAL NET OTHER PRODUCTION PLANT	4,698,167,116	71,613,127	1,089,588,797	382,589,048	2,167,100,967	293,125,332	692,721,661	1,428,183	0	0	0
SNPPO											
SYSTEM NET PLANT PRODUCTION OTHER	100.0000%	1.5243%	23.1918%	8.1434%	46.1265%	6.2391%	14.7445%	0.0304%	0.0000%	0.0000%	0.0000%
<b>PRODUCTION :</b>											
	<b>TOTAL</b>	<b>California</b>	<b>Oregon</b>	<b>Washington</b>	<b>Utah</b>	<b>Idaho</b>	<b>Wyoming</b>	<b>FERC</b>	<b>Other</b>	<b>Non-Utility</b>	
TOTAL PRODUCTION PLANT											
S	748,763	0	390,301	0	358,462	0	0	0	0	0	0
DGP & DGU	0	0	0	0	0	0	0	0	0	0	0
SG	13,471,637,631	197,668,816	3,512,102,007	1,056,034,376	5,980,724,306	809,093,802	1,912,072,210	3,942,115	0	0	0
SSGCH	0	0	0	0	0	0	0	0	0	0	0
SSGCT	0	0	0	0	0	0	0	0	0	0	0
	13,472,386,393	197,668,816	3,512,492,308	1,056,034,376	5,981,082,767	809,093,802	1,912,072,210	3,942,115	0	0	0
LESS ACCUMULATED DEPRECIATION											
S	(190,194,333)	0	(183,195,467)	(1,784,808)	(8,531,598)	1,213,075	0	0	2,104,465	0	0
DGP	0	0	0	0	0	0	0	0	0	0	0
DGU	0	0	0	0	0	0	0	0	0	0	0
SG	(5,820,591,304)	(85,405,310)	(1,517,448,061)	(456,272,999)	(2,584,047,526)	(349,579,203)	(826,134,965)	(1,703,240)	0	0	0
SSGCH	0	0	0	0	0	0	0	0	0	0	0
SSGCT	0	0	0	0	0	0	0	0	0	0	0
	(6,010,785,637)	(85,405,310)	(1,700,643,528)	(458,057,807)	(2,592,579,123)	(348,366,128)	(826,134,965)	(1,703,240)	2,104,465	0	0
TOTAL NET PRODUCTION PLANT	7,461,600,757	112,263,506	1,811,848,780	597,976,569	3,388,503,644	460,727,674	1,085,937,245	2,238,874	2,104,465	0	0
SNPP											
SYSTEM NET PRODUCTION PLANT	100.0000%	1.5045%	24.2823%	8.0141%	45.4126%	6.1746%	14.5537%	0.0300%	0.0282%	0.0000%	0.0000%
<b>TRANSMISSION :</b>											
	<b>TOTAL</b>	<b>California</b>	<b>Oregon</b>	<b>Washington</b>	<b>Utah</b>	<b>Idaho</b>	<b>Wyoming</b>	<b>FERC</b>	<b>Other</b>	<b>Non-Utility</b>	
TRANSMISSION PLANT											
DGP	0	0	0	0	0	0	0	0	0	0	0
DGU	0	0	0	0	0	0	0	0	0	0	0
SG	8,043,847,692	118,027,065	2,097,058,605	630,552,863	3,571,060,677	483,105,877	1,141,688,787	2,353,817	0	0	0
	8,043,847,692	118,027,065	2,097,058,605	630,552,863	3,571,060,677	483,105,877	1,141,688,787	2,353,817	0	0	0
LESS ACCUMULATED DEPRECIATION											
DGP	(353,157,214)	(5,181,862)	(92,069,293)	(27,683,803)	(156,783,903)	(21,210,288)	(50,124,722)	(103,342)	0	0	0
DGU	(426,788,101)	(6,262,245)	(111,265,118)	(33,455,688)	(189,472,285)	(25,632,489)	(60,575,387)	(124,888)	0	0	0
SG	(1,394,500,313)	(20,461,449)	(363,551,001)	(109,314,124)	(619,087,460)	(83,752,369)	(197,925,848)	(408,063)	0	0	0
	(2,174,445,627)	(31,905,556)	(566,885,412)	(170,453,615)	(965,343,648)	(130,595,146)	(308,625,957)	(636,293)	0	0	0
TOTAL NET TRANSMISSION PLANT	5,869,402,064	86,121,509	1,530,173,193	460,099,248	2,605,717,029	352,510,731	833,062,830	1,717,524	0	0	0
SNPT											
SYSTEM NET PLANT TRANSMISSION	100.0000%	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	0.0000%	0.0000%	0.0000%

OREGON GENERAL RATE CASE  
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	
<b>DISTRIBUTION :</b>										
DISTRIBUTION PLANT - PACIFIC POWER										
S		4,161,328,920	342,198,781	2,484,208,127	619,411,435	0	0	715,510,577	0	
LESS ACCUMULATED DEPRECIATION										
S		(1,887,598,178)	(160,091,570)	(1,122,481,268)	(290,502,417)	0	0	(314,522,923)	0	
		2,273,730,742	182,107,211	1,361,726,859	328,909,018	0	0	400,987,655	0	
<b>DNDP</b>										
<b>DIVISION NET PLANT DISTRIBUTION PACIFIC POWER</b>		100.0000%	8.0092%	59.8895%	14.4656%	0.0000%	0.0000%	17.6357%	0.0000%	
DISTRIBUTION PLANT - ROCKY MOUNTAIN POWER										
S		4,270,721,744	0	0	0	3,671,327,019	444,343,741	155,050,984	0	
LESS ACCUMULATED DEPRECIATION										
S		(1,400,541,394)	0	0	0	(1,167,331,507)	(171,058,258)	(62,150,629)	0	
		2,870,180,350	0	0	0	2,503,995,512	273,284,484	92,900,355	0	
<b>DNPDU</b>										
<b>DIVISION NET PLANT DISTRIBUTION R.M.P.</b>		100.0000%	0.0000%	0.0000%	0.0000%	87.2417%	9.5215%	3.2367%	0.0000%	
TOTAL NET DISTRIBUTION PLANT		5,143,911,093	182,107,211	1,361,726,859	328,909,018	2,503,995,512	273,284,484	493,888,009	0	
<b>DNDP &amp; SNPD</b>										
<b>SYSTEM NET PLANT DISTRIBUTION</b>		100.0000%	3.5402%	26.4726%	6.3941%	48.6788%	5.3128%	9.6014%	0.0000%	
<b>GENERAL :</b>										
GENERAL PLANT										
S		765,688,819	23,960,387	245,798,256	49,662,967	280,296,094	54,885,092	111,086,024	0	
DGP		0	0	0	0	0	0	0	0	
DGU		0	0	0	0	0	0	0	0	
SE		3,050,541	43,112	764,714	225,072	1,349,803	195,969	470,834	1,037	
SG		324,821,855	4,766,098	84,682,168	25,462,609	144,204,440	19,508,493	46,102,995	95,050	
SO		406,724,719	8,968,614	110,519,641	31,222,891	178,696,358	23,761,896	53,471,621	83,699	
CN		15,505,877	363,465	4,805,260	1,061,256	7,489,022	657,857	1,129,017	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		(14,049,314)	(144,981)	(4,188,634)	(774,554)	(6,942,398)	(593,434)	(1,402,420)	(2,891)	
		1,501,742,497	37,956,695	442,381,405	106,860,240	605,093,318	98,415,872	210,858,071	176,896	
LESS ACCUMULATED DEPRECIATION										
S		(316,749,024)	(8,585,221)	(113,784,391)	(28,055,843)	(102,370,087)	(22,807,495)	(41,145,986)	0	
DGP		(715,242)	(10,495)	(186,466)	(56,067)	(317,531)	(42,957)	(101,517)	(209)	
DGU		(1,951,711)	(28,637)	(508,818)	(152,994)	(866,461)	(117,218)	(277,012)	(571)	
SE		(1,494,391)	(21,120)	(374,616)	(110,258)	(661,238)	(96,001)	(230,651)	(508)	
SG		(138,970,814)	(2,039,113)	(36,230,166)	(10,893,847)	(61,695,998)	(8,346,455)	(19,724,568)	(40,666)	
SO		(127,417,065)	(2,809,651)	(34,623,143)	(9,781,380)	(55,981,268)	(7,444,030)	(16,751,372)	(26,221)	
CN		(6,909,506)	(161,962)	(2,141,251)	(472,901)	(3,337,151)	(293,145)	(503,097)	0	
SSGCT		(130,406)	(1,913)	(33,997)	(10,222)	(57,894)	(7,832)	(18,509)	(38)	
SSGCH		0	0	0	0	0	0	0	0	
		(594,338,157)	(13,658,112)	(187,882,849)	(49,533,513)	(225,287,626)	(39,155,132)	(78,752,711)	(68,214)	
TOTAL NET GENERAL PLANT		907,404,339	24,298,582	254,498,557	57,326,727	379,805,692	59,260,740	132,105,360	108,682	
<b>SNPG</b>										
<b>SYSTEM NET GENERAL PLANT</b>		100.0000%	2.6778%	28.0469%	6.3177%	41.8563%	6.5308%	14.5586%	0.0120%	
<b>MINING :</b>										
		<b>TOTAL</b>	<b>California</b>	<b>Oregon</b>	<b>Washington</b>	<b>Utah</b>	<b>Idaho</b>	<b>Wyoming</b>	<b>FERC</b>	

**OREGON GENERAL RATE CASE  
Pro Forma Factors December 31, 2023**

DESCRIPTION	2020 PROTOCOL FACTOR	2020 PROTOCOL FACTOR							OTHER	NON-UTILITY	Page Ref.
		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL			
GENERAL MINING PLANT	SE	50,741,701	717,118	12,719,998	3,743,773	22,452,176	3,259,688	7,831,691	17,257		
LESS ACCUMULATED DEPRECIATION	SE	0	0	0	0	0	0	0	0		
		50,741,701	717,118	12,719,998	3,743,773	22,452,176	3,259,688	7,831,691	17,257		
<b>SNPM</b>											
<b>SYSTEM NET PLANT MINING</b>		100.0000%	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%		
<b>INTANGIBLE :</b>											
INTANGIBLE PLANT		<u>TOTAL</u>	<u>California</u>	<u>Oregon</u>	<u>Washington</u>	<u>Utah</u>	<u>Idaho</u>	<u>Wyoming</u>	<u>FERC</u>		
S		(9,145,629)	481,167	4,609,463	2,036,986	(26,172,704)	4,369,593	5,529,866	0		
DGP		0	0	0	0	0	0	0	0		
DGU		0	0	0	0	0	0	0	0		
SE		(64,323)	(909)	(16,125)	(4,746)	(28,462)	(4,132)	(9,928)	(22)		
CN		213,633,287	5,007,658	66,204,803	14,621,522	103,180,524	9,063,664	15,555,115	0		
SG		397,257,319	5,828,941	103,566,342	31,140,786	176,362,115	23,858,898	56,383,990	116,247		
SO		476,788,634	10,513,580	129,558,166	36,601,462	209,479,258	27,855,208	62,682,842	98,118		
SSGCT		0	0	0	0	0	0	0	0		
SSGCH		0	0	0	0	0	0	0	0		
		1,078,469,287	21,830,438	303,922,649	84,396,010	462,820,731	65,143,232	140,141,885	214,342		
LESS ACCUMULATED AMORTIZATION											
S		30,343,931	(8,850)	(140,175)	(15,414)	31,928,632	(1,020,506)	(399,756)	0		
DGP		0	0	0	0	0	0	0	0		
DGU		(397,058)	(5,826)	(103,514)	(31,125)	(176,274)	(23,847)	(56,356)	(116)		
SE		84,709	1,197	21,235	6,250	37,482	5,442	13,074	29		
CN		(182,729,117)	(4,283,251)	(56,627,623)	(12,506,374)	(88,254,439)	(7,752,516)	(13,304,914)	0		
SG		(240,029,881)	(3,521,949)	(62,576,611)	(18,815,812)	(106,561,101)	(14,415,967)	(34,068,202)	(70,238)		
SO		(339,134,793)	(7,478,200)	(92,153,375)	(26,034,239)	(149,000,416)	(19,813,120)	(44,585,653)	(69,790)		
SSGCT		0	0	0	0	0	0	0	0		
SSGCH		0	0	0	0	0	0	0	0		
		(731,862,209)	(15,296,879)	(211,580,064)	(57,396,715)	(312,026,116)	(43,020,514)	(92,401,806)	(140,116)		
TOTAL NET INTANGIBLE PLANT		346,607,078	6,533,558	92,342,586	26,999,296	150,794,614	22,122,718	47,740,079	74,227		
<b>SNPI</b>											
<b>SYSTEM NET INTANGIBLE PLANT</b>		100.0000%	1.8850%	26.6419%	7.7896%	43.5059%	6.3827%	13.7735%	0.0214%		
<b>GROSS PLANT :</b>											
PRODUCTION PLANT		<u>TOTAL</u>	<u>California</u>	<u>Oregon</u>	<u>Washington</u>	<u>Utah</u>	<u>Idaho</u>	<u>Wyoming</u>	<u>FERC</u>	<u>Other</u>	<u>Non-Utility</u>
TRANSMISSION PLANT		13,472,386,393	197,668,816	3,512,492,308	1,056,034,376	5,981,082,767	809,093,802	1,912,072,210	3,942,115	0	0
DISTRIBUTION PLANT		8,043,847,692	118,027,065	2,097,058,605	630,552,863	3,571,060,677	483,105,877	1,141,688,787	2,353,817	0	0
GENERAL PLANT		8,432,050,664	342,198,781	2,484,208,127	619,411,435	3,671,327,019	444,343,741	870,561,561	0	0	0
INTANGIBLE PLANT		1,552,484,198	38,673,812	455,101,404	110,604,013	627,545,494	101,675,560	218,689,762	194,152	0	0
		1,078,469,287	21,830,438	303,922,649	84,396,010	462,820,731	65,143,232	140,141,885	214,342	0	0
TOTAL GROSS PLANT		32,579,238,234	718,398,912	8,852,783,093	2,500,998,697	14,313,836,688	1,903,362,212	4,283,154,205	6,704,427	0	0
<b>GPS</b>											
<b>GROSS PLANT-SYSTEM FACTOR</b>		100.0000%	2.2051%	27.1731%	7.6767%	43.9355%	5.8423%	13.1469%	0.0206%	0.0000%	0.0000%
<b>ACCUMULATED DEPRECIATION AND AMORTIZATION</b>											
PRODUCTION PLANT		(6,010,785,637)	(85,405,310)	(1,700,643,528)	(458,057,807)	(2,592,579,123)	(348,366,128)	(826,134,965)	(1,703,240)	2,104,465	0
TRANSMISSION PLANT		(2,174,445,627)	(31,905,556)	(566,885,412)	(170,453,615)	(965,343,648)	(130,595,146)	(308,625,957)	(636,293)	0	0
DISTRIBUTION PLANT		(3,288,139,572)	(160,091,570)	(1,122,481,268)	(290,502,417)	(1,167,331,507)	(171,059,258)	(376,673,552)	0	0	0
GENERAL PLANT		(594,338,157)	(13,658,112)	(187,882,849)	(49,533,513)	(225,287,626)	(39,155,132)	(78,752,711)	(68,214)	0	0

OREGON GENERAL RATE CASE  
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2020 PROTOCOL  
FACTOR

DESCRIPTION	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
INTANGIBLE PLANT	(731,862,209)	(211,580,064)	(57,396,715)	(312,026,116)	(43,020,514)	(92,401,806)	(140,116)	0	0	
	(12,799,571,202)	(3,789,473,120)	(1,025,944,066)	(5,262,568,021)	(732,196,177)	(1,682,588,991)	(2,547,863)	2,104,465	0	
NET PLANT	19,779,667,032	412,041,484	5,063,309,973	1,475,054,632	9,051,268,667	1,171,166,034	4,156,563	2,104,465	0	
SNP										
SYSTEM NET PLANT FACTOR (SNP)	100.0000%	2.0832%	25.5986%	7.4574%	45.7605%	5.9211%	13.1477%	0.0210%	0.0106%	0.0000%
NON-UTILITY RELATED INTEREST PERCENTAGE	0.0000%									
INT										
INTEREST FACTOR SNP - NON-UTILITY	100.0000%	2.0832%	25.5986%	7.4574%	45.7605%	5.9211%	13.1477%	0.0210%	0.0106%	0.0000%
TOTAL GROSS PLANT (LESS SO FACTOR)	31,695,724,881	698,916,719	8,612,705,286	2,433,174,345	13,925,661,073	1,851,745,108	4,166,999,742	6,522,610	0	0
SO										
SYSTEM OVERHEAD FACTOR (SO)	100.0000%	2.2051%	27.1731%	7.6767%	43.9355%	5.8423%	13.1469%	0.0206%	0.0000%	0

IBT	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
INCOME BEFORE TAXES										
INCOME BEFORE STATE TAXES	211,149,047	12,992,336	(35,577,313)	33,446,441	279,930,728	33,044,431	(24,722,110)	11,311,555	(56,303,100)	(42,973,921)
Interest Synchronization	(14,670,379)	(305,607)	(3,755,406)	(1,094,033)	(6,713,234)	(868,642)	(1,928,813)	(3,083)	(1,561)	-
	196,478,668	12,686,729	(39,332,719)	32,352,408	273,217,494	32,175,789	(26,650,923)	11,308,472	(56,304,661)	(42,973,921)
INCOME BEFORE TAXES (FACTOR)	100.0000%	6.4571%	-20.0188%	16.4661%	139.0571%	16.3762%	-13.5643%	5.7556%	-28.6569%	-21.8721%

See Calculation of EXCTAX

DITEXP:	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Pacific Power										
Production	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0
Distribution	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0
Mining Plant	0	0	0	0	0	0	0	0	0	0
Non Utility	0	0	0	0	0	0	0	0	0	0
Total Pacific Power	0	0	0	0	0	0	0	0	0	0
Rocky Mountain Power										
Production	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0
Distribution	0	0	0	0	0	0	0	0	0	0
General	0	0	0	0	0	0	0	0	0	0
Mining Plant	0	0	0	0	0	0	0	0	0	0
Non-Utility	0	0	0	0	0	0	0	0	0	0

**OREGON GENERAL RATE CASE  
Pro Forma Factors December 31, 2023**

DESCRIPTION	2020 PROTOCOL FACTOR	2020 PROTOCOL FACTOR									
		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Total Rocky Mountain Power		0	0	0	0	0	0	0	0	0	0
PC (Post Merger)											
Prod / Other Prod	S	0	0	0	0	0	0	0	0	0	0
Cholla Unit 4	S	0	0	0	0	0	0	0	0	0	0
Gadsby Unit 4, 5 & 6	S	0	0	0	0	0	0	0	0	0	0
Hydro-PPL	S	0	0	0	0	0	0	0	0	0	0
Hydro-UPL	S	0	0	0	0	0	0	0	0	0	0
Transmission	S	0	0	0	0	0	0	0	0	0	0
Distribution	S	0	0	0	0	0	0	0	0	0	0
General/ Intangibles	S	0	0	0	0	0	0	0	0	0	0
Mining	S	0	0	0	0	0	0	0	0	0	0
WCA - CAEE 2007+	S	0	0	0	0	0	0	0	0	0	0
WCA - CAGE 2007+	S	0	0	0	0	0	0	0	0	0	0
WCA - CAGW 2007+	S	0	0	0	0	0	0	0	0	0	0
WCA_CAGW 2007+ -Marengo	S	0	0	0	0	0	0	0	0	0	0
WCA CAGW 2007+ -Goodnoe	S	0	0	0	0	0	0	0	0	0	0
WCA - General 2007+	S	0	0	0	0	0	0	0	0	0	0
WCA - JBG 2007+	S	0	0	0	0	0	0	0	0	0	0
Non Utility	NUTIL	0	0	0	0	0	0	0	0	0	0
Total PC (Post Merger)		0	0	0	0	0	0	0	0	0	0
Total Deferred Taxes		0	0	0	0	0	0	0	0	0	0
<b>Percentage of Total (DITEXP)</b>		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
<b>DITBAL :</b>		<b>TOTAL</b>	<b>California</b>	<b>Oregon</b>	<b>Washington</b>	<b>Utah</b>	<b>Idaho</b>	<b>Wyoming</b>	<b>FERC</b>	<b>Other</b>	<b>Non-Utility</b>
Pacific Power											
Production	S	(4,349,402)	468,901	1,431,767	1,826,359	(7,592,625)	(152,348)	(325,385)	(6,071)	0	0
Transmission	S	8,160,089	325,899	4,555,414	1,265,919	209,709	(14,833)	1,818,110	(128)	0	0
Distribution	S	(2,545,761)	721,849	(632,519)	1,147,165	(3,360,768)	(10,960)	(410,530)	0	0	0
General	S	(805,521)	(2,953)	(302,710)	(11,031)	(344,410)	(8,276)	(135,909)	(232)	0	0
Mining Plant	S	5,219	80	1,311	400	2,226	329	865	9	0	0
Non Utility	NUTIL	(2,416,451)	0	0	0	0	0	0	0	0	(2,416,451)
Total Pacific Power		(1,951,828)	1,513,776	5,053,262	4,228,811	(11,085,868)	(186,088)	947,152	(6,422)	0	(2,416,451)
Rocky Mountain Power											
Production	S	4,159,394	(63,931)	(5,489,678)	(343,345)	10,521,820	1,445,542	(2,039,523)	128,509	0	0
Transmission	S	18,500,601	(1,678)	(227,196)	(8,199)	16,181,239	1,940,549	528,149	87,737	0	0
Distribution	S	19,040,430	374,205	2,323,142	706,648	12,714,298	1,606,235	1,315,902	0	0	0
General	S	(1,273,079)	(19,808)	(376,417)	(71,848)	(495,829)	(111,007)	(197,220)	(949)	0	0
Mining Plant	S	(7,460)	(100)	(1,843)	(572)	(3,447)	(525)	(983)	10	0	0
Non-Utility Plant	NUTIL	0	0	0	0	0	0	0	0	0	0
Total Rocky Mountain Power		40,419,886	288,688	(3,771,992)	282,683	38,918,080	4,880,794	(393,675)	215,307	0	0



**OREGON GENERAL RATE CASE  
Pro Forma Factors December 31, 2023**

DESCRIPTION	2020 PROTOCOL FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
PacifiCorp										
Prod / Other Prod	S	201,415,866	3,574,055	56,780,026	16,384,713	82,579,284	11,194,505	30,219,812	683,471	0
Cholla Unit 4	S	65,295	1,035	17,220	(0)	27,627	3,672	10,105	197	0
Gadsby Unit 4, 5 & 6	S	5,076,586	78,501	1,311,363	(1,099)	2,209,563	292,174	750,146	12,047	0
Hydro-PPL	S	20,412,703	398,320	6,052,425	1,728,099	8,093,112	1,081,951	2,993,791	65,006	0
Hydro-UPL	S	6,209,185	124,985	1,849,673	540,490	2,459,238	323,887	893,095	17,816	0
Transmission	S	173,854,203	3,144,070	50,590,154	14,199,142	70,350,661	9,377,231	25,660,293	532,654	0
Distribution	S	669,013,369	23,441,538	189,501,130	43,421,752	314,080,996	32,825,482	65,737,809	0	4,661
General/ Intangibles	S	5,218,463	151,692	2,265,016	266,134	1,255,673	275,029	964,216	40,703	0
Mining	S	1,966	29	493	151	841	126	325	1	0
WCA - CAEE 2007+	S	(3,001)	(18)	(706)	0	(1,162)	(187)	(467)	(1)	0
WCA - CAGE 2007+	S	1,519,765,498	23,833,468	400,112,661	(423,655)	648,356,473	86,254,785	228,821,189	3,586,383	0
WCA - CAGW 2007+	S	373,581,042	5,880,824	98,890,328	80,287,813	158,412,485	21,178,359	55,701,373	873,362	0
WCA_CAGW 2007+ -Marengo	S	(51,824,378)	0	0	0	(51,824,378)	0	0	0	0
WCA CAGW 2007+ -Goodnoe	S	(8,496,901)	0	0	0	0	0	0	0	(8,496,901)
WCA - General 2007+	S	144,948,307	3,178,224	39,910,091	9,759,863	62,280,350	8,220,362	19,878,392	145,604	0
WCA - JBG 2007+	S	107,482,603	1,696,346	28,520,663	23,592,642	46,492,527	6,208,145	16,479,778	216,010	0
Oregon Extra Book Depreciation	S	(123,478,470)	0	(123,478,470)	0	0	0	0	0	0
Non Utility	NUTIL	(5,039,052)	0	0	(5,039,052)	0	0	0	0	0
<b>Total PC (Post Merger)</b>		<b>3,038,203,288</b>	<b>65,503,072</b>	<b>752,322,068</b>	<b>184,716,992</b>	<b>1,344,773,290</b>	<b>177,235,521</b>	<b>448,109,855</b>	<b>6,173,251</b>	<b>0</b>
<b>Total Deferred Taxes</b>		<b>3,076,671,345</b>	<b>67,305,536</b>	<b>753,603,338</b>	<b>189,228,486</b>	<b>1,372,605,502</b>	<b>181,930,228</b>	<b>448,663,332</b>	<b>6,382,136</b>	<b>0</b>
<b>Percentage of Total (DITBAL)</b>		<b>100.0000%</b>	<b>2.1876%</b>	<b>24.4941%</b>	<b>6.1504%</b>	<b>44.6133%</b>	<b>5.9132%</b>	<b>14.5828%</b>	<b>0.2074%</b>	<b>0.0000%</b>

**OPRV-WY**

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers	0	0	0
Less: Uncollectibles (net)	0	0	0
<b>Total Interstate Revenues</b>	<b>0</b>	<b>0</b>	<b>0</b>
	0.0000%	0.0000%	0.0000%

**OPRV-ID**

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers	0	0	0
Less: Interstate Sales for Resale			
Montana Power	0	0	0
Portland General Electric	0	0	0
Puget Sound Power & Light	0	0	0
Washington Water Power Co.	0	0	0
Less: Uncollectibles (net)	0	0	0
<b>Total Interstate Revenues</b>	<b>0</b>	<b>0</b>	<b>0</b>
	0.0000%	0.0000%	0.0000%

OREGON GENERAL RATE CASE  
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
		<u>TOTAL</u>	<u>California</u>	<u>Oregon</u>	<u>Washington</u>	<u>Utah</u>	<u>Idaho</u>	<u>Wyoming</u>	<u>FERC</u>	<u>OTHER</u>
<b>BADDEBT</b>										
Account 904 Balance	12,972,501	264,963	6,289,730	1,908,655	3,714,434	699,789	0	0	0	0
Bad Debts Expense Allocation Factor - BADDEBT		2.0425%	48.4851%	14.7131%	28.6331%	5.3944%	0.7318%	0.0000%	0.0000%	0.0000%
<b>Customer Factors</b>										
Total Electric Customers	2,038,430	47,782	631,708	139,515	984,520	86,483	148,423	0	0	0
<b>CN</b>										
Customer System factor - CN	100.0000%	2.3440%	30.9899%	6.8442%	48.2980%	4.2426%	7.2812%	0.0000%	0.0000%	0.0000%
Pacific Power Customers	950,780	47,782	631,708	139,515	0	0	131775.9167	0	0	0
<b>CNP</b>										
Customer Service Pacific Power factor - CNP	100.0000%	5.0255%	66.4410%	14.6737%	0.0000%	0.0000%	13.8598%	0.0000%	0.0000%	0.0000%
Rocky Mountain Power Customers	1,087,650	0	0	0	984,520	86,483	16,647	0	0	0
<b>CNU</b>										
Customer Service R.M.P. factor - CNU	100.0000%	0.0000%	0.0000%	0.0000%	90.5181%	7.9514%	1.5305%	0.0000%	0.0000%	0.0000%
<b>CIAC</b>										
TOTAL NET DISTRIBUTION PLANT	5,143,911,093	182,107,211	1,361,726,859	328,909,018	2,503,995,512	273,284,484	493,888,009	0	0	0
CIAC FACTOR: Same as (SNPD Factor)	100.0000%	3.5402%	26.4726%	6.3941%	48.6788%	5.3128%	9.6014%	0.0000%	0.0000%	0.0000%

IDSIT		Total Company	Idaho - PPL	Idaho - UPL	Idaho Total
		Payroll	0	0	0
Idaho State Income Tax Allocation			0.00%	0.00%	0.00%
Property	0	0	0	0	
			0.00%	0.00%	0.00%
Sales	0	0	0	0	
			0.00%	0.00%	0.00%

OREGON GENERAL RATE CASE  
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.	
Average		0.00%	0.00%								
Idaho - PPL Factor		0.00%	0.00%								
Idaho - UPL Factor		0.00%	0.00%								
		0.00%	0.00%								
<b>EXCTAX</b>											
<b>Excise Tax (Superfund)</b>		<b>TOTAL</b>	<b>California</b>	<b>Oregon</b>	<b>Washington</b>	<b>Utah</b>	<b>Wyoming</b>	<b>FERC</b>	<b>Other</b>	<b>Non-Utility</b>	
Total Taxable Income		180,214,838	12,402,484	(39,807,739)	31,927,972	267,221,873	31,544,214	(23,599,726)	10,798,010	(69,249,346)	(41,022,905)
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		180,214,838	12,402,484	(39,807,739)	31,927,972	267,221,873	31,544,214	(23,599,726)	10,798,010	(69,249,346)	(41,022,905)
<b>Excise Tax (Superfund) Factor - EXCTAX</b>		100.0000%	6.8821%	-22.0890%	17.7166%	148.2796%	17.5037%	-13.0953%	5.9917%	-38.4260%	-22.7633%
<b>Trojan Allocators</b>		<b>TOTAL</b>	<b>California</b>	<b>Oregon</b>	<b>Washington</b>	<b>Utah</b>	<b>Idaho</b>	<b>Wyoming</b>	<b>FERC</b>	<b>Other</b>	<b>Non-Utility</b>
Premerger											
Dec 1991 Plant		16,918,976									
Dec 1992 Plant		17,094,202									
Average	SG	17,006,589	249,537	4,433,676	1,333,137	7,550,064	1,021,400	2,413,799	4,977	0	0
Dec 1991 Reserve		(7,851,432)									
Dec 1992 Reserve		(8,434,030)									
Average	SG	(8,142,731)	(119,478)	(2,122,838)	(638,304)	(3,614,960)	(489,045)	(1,155,724)	(2,383)	0	0
Postmerger											
Dec 1991 Plant		4,284,960									
Dec 1992 Plant		3,485,613									
Average	SG	3,885,287	57,009	1,012,908	304,566	1,724,871	233,347	551,451	1,137	0	0
Dec 1991 Reserve		(129,394)									
Dec 1992 Reserve		(240,609)									
Average	SG	(185,002)	(2,715)	(48,231)	(14,502)	(82,132)	(11,111)	(26,258)	(54)	0	0
Net Plant		12,564,143	184,353	3,275,515	984,896	5,577,843	754,591	1,783,269	3,677	0	0
<b>Division Net Plant Nuclear Pacific Power</b>	<b>DNPPNP</b>	100.0000%	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	0.0000%	0.0000%
<b>Division Net Plant Nuclear Rocky Mountain Power</b>	<b>DNPPNP</b>	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
<b>System Net Nuclear Plant</b>	<b>SNNP</b>	100.0000%	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	0.0000%	0.0000%

**OREGON GENERAL RATE CASE  
Pro Forma Factors December 31, 2023**

DESCRIPTION		2020 PROTOCOL FACTOR	2020 PROTOCOL FACTOR								Page Ref.	
			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL		OTHER
Account 182.22												
Pre-merger	(101)	SG	17,094,202	250,823	4,456,517	1,340,005	7,588,959	1,026,662	2,426,234	5,002	0	0
		(108) SG	(8,434,030)	(123,752)	(2,198,780)	(661,139)	(3,744,282)	(506,540)	(1,197,069)	(2,468)	0	0
Post-merger	(101)	SG	3,485,613	51,144	908,711	273,235	1,547,436	209,343	494,724	1,020	0	0
		(108) SG	(240,609)	(3,530)	(62,728)	(18,861)	(106,818)	(14,451)	(34,150)	(70)	0	0
		(107) SG	1,778,549	26,097	463,674	139,419	789,586	106,818	252,435	520	0	0
		(120) SE	1,975,759	27,923	495,286	145,773	874,233	126,924	304,947	672	0	0
		(228) SG	7,220,849	105,951	1,882,500	566,038	3,205,691	433,677	1,024,878	2,113	0	0
		(228) SG	1,472,376	21,604	383,853	115,419	653,660	88,430	208,979	431	0	0
		(228) SNNP	3,531,000	51,810	920,544	276,793	1,567,585	212,069	501,166	1,033	0	0
		(228) SE	1,743,025	24,634	436,944	128,602	771,253	111,973	269,026	593	0	0
Total Acct 182.22			29,626,734	432,703	7,686,521	2,305,286	13,147,303	1,794,905	4,251,170	8,846	0	0
Revised Study	(228)	SNNP	112,680	1,653	29,376	8,833	50,024	6,767	15,993	33	0	0
		(228) SE	941,950	13,312	236,129	69,498	416,794	60,512	145,385	320	0	0
December 1993 Adj.			1,054,630	14,966	265,505	78,331	466,818	67,279	161,378	353	0	0
Adjusted Acct 182.22			30,681,364	447,668	7,952,026	2,383,617	13,614,121	1,862,184	4,412,548	9,199	0	0
<b>TROJP</b>			100.0000%	1.4591%	25.9181%	7.7689%	44.3726%	6.0694%	14.3819%	0.0300%	0.0000%	0.0000%
Trojan Plant Allocator												
Account 228.42			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Plant - Premerger		SG	7,220,849	105,951	1,882,500	566,038	3,205,691	433,677	1,024,878	2,113	0	0
- Postmerger		SG	1,472,376	21,604	383,853	115,419	653,660	88,430	208,979	431	0	0
Storage Facility		SE	1,743,025	24,634	436,944	128,602	771,253	111,973	269,026	593	0	0
Transition Costs		SNNP	3,531,000	51,810	920,544	276,793	1,567,585	212,069	501,166	1,033	0	0
Total Acct 228.42			13,967,250	203,999	3,623,841	1,086,853	6,198,190	846,149	2,004,049	4,170	0	0
Transition Costs		SNNP	112,680	1,653	29,376	8,833	50,024	6,767	15,993	33	0	0
Storage Facility		SE	941,950	13,312	236,129	69,498	416,794	60,512	145,385	320	0	0
December 1993 Adj.			1,054,630	14,966	265,505	78,331	466,818	67,279	161,378	353	0	0
Adjusted Acct 228.42			15,021,880	218,965	3,889,346	1,165,183	6,665,008	913,428	2,165,427	4,523	0	0
<b>TROJD</b>			100.0000%	1.4576%	25.8912%	7.7566%	44.3687%	6.0806%	14.4152%	0.0301%	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		58,576,334	1,127,735	15,333,788	4,122,769	24,274,949	2,955,813	6,519,428	9,115	4,232,738	0
Amortization of Other Electric Plant	Acct 405		0	0	0	0	0	0	0	0	0	0
Amortization of Plant Acquisitions	Acct 406		2,091,631	26,265	466,658	140,317	1,096,303	107,505	254,060	524	0	0
Amort of Prop. Losses, Unrecovered Plant, etc.	Acct 407		29,604,150	14,110	27,436,855	75,384	1,758,983	57,756	136,491	281	124,290	0
Total Amortization Expense :			90,272,115	1,168,110	43,237,301	4,338,470	27,130,234	3,121,074	6,909,979	9,920	4,357,028	0
<b>Schedule M Amortization Factor</b>			100.0000%	1.2940%	47.8966%	4.8060%	30.0538%	3.4574%	7.6546%	0.0110%	4.8265%	0.0000%
SCHMD			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Depreciation Expense :												
Steam	Acct 403.1		626,491,403	6,540,257	116,204,721	34,940,950	197,883,888	26,770,441	63,264,626	130,433	180,756,088	0

OREGON GENERAL RATE CASE  
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR										
		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.	
Nuclear	Acct 403.2	0	0	0	0	0	0	0	0	0	
Hydro	Acct 403.3	34,898,599	512,066	9,098,184	2,735,682	15,493,209	2,095,977	4,953,269	10,212	0	
Other	Acct 403.4	209,943,056	3,080,416	54,731,626	16,456,947	93,206,736	12,608,694	29,797,204	61,433	0	
Transmission	Acct 403.5	138,230,148	2,028,246	36,037,072	10,835,786	61,367,180	8,301,972	19,619,443	40,449	0	
Distribution	Acct 403.6	209,732,961	9,254,102	56,428,045	16,032,588	93,266,338	11,380,194	23,371,694	0	0	
General	Acct 403.7&8	52,330,149	1,160,256	15,494,647	3,791,197	21,488,305	3,123,110	7,264,733	7,902	0	
Mining	Acct 403.9	0	0	0	0	0	0	0	0	0	
Experimental	Acct 403.4	0	0	0	0	0	0	0	0	0	
<hr/>											
Total Depreciation Expense :		1,271,626,317	22,575,342	287,994,295	84,793,152	482,705,656	64,280,387	148,270,968	250,428	180,756,088	0
Schedule M Depreciation Factor		100.0000%	1.7753%	22.6477%	6.6681%	37.9597%	5.0550%	11.6599%	0.0197%	14.2146%	0.0000%
Tax Depreciation by Function		<u>TOTAL</u>	<u>California</u>	<u>Oregon</u>	<u>Washington</u>	<u>Utah</u>	<u>Idaho</u>	<u>Wyoming</u>	<u>FERC</u>	<u>Other</u>	<u>Non-Utility</u>
Based on Tax Depreciation Schedule M Differences		1,383,505,094	26,312,380	365,379,467	61,454,308	622,023,458	80,859,265	183,833,144	328,367	-	43,314,704
Tax Depr factor		100.0000%	1.9019%	26.4097%	4.4419%	44.9600%	5.8445%	13.2875%	0.0237%	0.0000%	3.1308%

**Pro Forma Factors December 31, 2023**  
**Oregon General Rate Case - December 2023**  
**COINCIDENTAL PEAKS**

			FORECAST LOADS (CP)								
			Non-FERC						FERC		
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total	
Jan-23	12	8	148	2,655	838	3,495	469	1,223	33	8,861	
Feb-23	7	8	139	2,484	704	3,438	453	1,184	34	8,436	
Mar-23	9	8	135	2,379	674	3,295	437	1,167	34	8,120	
Apr-23	5	8	117	2,196	576	3,088	426	1,105	34	7,542	
May-23	16	16	113	1,917	577	4,075	545	1,095	22	8,344	
Jun-23	22	16	129	2,051	684	4,913	769	1,200	34	9,780	
Jul-23	17	16	140	2,409	760	5,176	783	1,237	35	10,541	
Aug-23	24	16	132	2,474	743	5,033	616	1,202	36	10,236	
Sep-23	7	16	116	2,161	660	4,673	556	1,146	36	9,348	
Oct-23	2	18	103	1,901	602	3,783	429	1,129	35	7,983	
Nov-23	22	18	122	2,196	695	3,730	466	1,236	34	8,479	
Dec-23	13	18	136	2,398	726	3,923	494	1,282	36	8,995	
			1,531	27,220	8,239	48,623	6,443	14,205	404	106,665	

**- (less)**

			Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)								
			Non-FERC						FERC		
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total	
Jan-23	12	8	-	-	-	198	-	-	30	228	
Feb-23	7	8	-	-	-	201	-	-	32	233	
Mar-23	9	8	-	-	-	202	-	-	32	233	
Apr-23	5	8	-	-	-	202	-	-	32	234	
May-23	16	16	-	-	-	233	-	-	21	254	
Jun-23	22	16	-	-	-	359	170	-	31	560	
Jul-23	17	16	-	-	-	385	146	-	32	563	
Aug-23	24	16	-	-	-	305	79	-	33	417	
Sep-23	7	16	-	-	-	352	-	-	34	386	
Oct-23	2	18	-	-	-	220	-	-	33	252	
Nov-23	22	18	-	-	-	222	-	-	32	255	
Dec-23	13	18	-	-	-	304	-	-	33	337	
			-	-	-	3,182	395	-	376	3,953	

**= equals**

			COINCIDENTAL PEAK SERVED FROM COMPANY RESOURCES								
			Non-FERC						FERC		
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total	
Jan-23	12	8	148	2,655	838	3,297	469	1,223	3	8,633	
Feb-23	7	8	139	2,484	704	3,237	453	1,184	3	8,204	
Mar-23	9	8	135	2,379	674	3,093	437	1,167	2	7,886	
Apr-23	5	8	117	2,196	576	2,886	426	1,105	2	7,308	
May-23	16	16	113	1,917	577	3,842	545	1,095	1	8,090	
Jun-23	22	16	129	2,051	684	4,554	599	1,200	2	9,219	
Jul-23	17	16	140	2,409	760	4,791	637	1,237	3	9,978	
Aug-23	24	16	132	2,474	743	4,728	537	1,202	3	9,818	
Sep-23	7	16	116	2,161	660	4,321	556	1,146	2	8,962	
Oct-23	2	18	103	1,901	602	3,563	429	1,129	2	7,730	
Nov-23	22	18	122	2,196	695	3,508	466	1,236	2	8,225	
Dec-23	13	18	136	2,398	726	3,619	494	1,282	3	8,658	
			1,531	27,220	8,239	45,441	6,048	14,205	29	102,712	

**+ plus**

			Adjustments for Ancillary Services Contracts including Reserves and Direct Access (Additions to Load)								
			Non-FERC						FERC		
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total	
Jan-23	12	8	-	-	-	30	-	-	-	30	
Feb-23	7	8	-	-	-	32	-	-	-	32	
Mar-23	9	8	-	-	-	32	-	-	-	32	
Apr-23	5	8	-	-	-	32	-	-	-	32	
May-23	16	16	-	-	-	21	-	-	-	21	
Jun-23	22	16	-	-	-	31	-	-	-	31	
Jul-23	17	16	-	-	-	32	-	-	-	32	
Aug-23	24	16	-	-	-	33	-	-	-	33	
Sep-23	7	16	-	-	-	34	-	-	-	34	
Oct-23	2	18	-	-	-	33	-	-	-	33	
Nov-23	22	18	-	-	-	32	-	-	-	32	
Dec-23	13	18	-	-	-	33	-	-	-	33	
			-	-	-	376	-	-	-	376	

**= equals**

			LOADS FOR JURISDICTIONAL ALLOCATION (CP)								
			Non-FERC						FERC		
Month	Day	Time	CA	OR	WA	UT	ID	WY		Total	
Jan-23	12	8	148	2,655	838	3,327	469	1,223	3	8,663	
Feb-23	7	8	139	2,484	704	3,269	453	1,184	3	8,235	
Mar-23	9	8	135	2,379	674	3,125	437	1,167	2	7,918	
Apr-23	5	8	117	2,196	576	2,919	426	1,105	2	7,341	
May-23	16	16	113	1,917	577	3,863	545	1,095	1	8,112	
Jun-23	22	16	129	2,051	684	4,585	599	1,200	2	9,251	
Jul-23	17	16	140	2,409	760	4,823	637	1,237	3	10,010	
Aug-23	24	16	132	2,474	743	4,761	537	1,202	3	9,852	
Sep-23	7	16	116	2,161	660	4,355	556	1,146	2	8,996	
Oct-23	2	18	103	1,901	602	3,596	429	1,129	2	7,763	
Nov-23	22	18	122	2,196	695	3,540	466	1,236	2	8,257	
Dec-23	13	18	136	2,398	726	3,652	494	1,282	3	8,691	
			1,531	27,220	8,239	45,816	6,048	14,205	29	103,088	

Pro Forma Factors December 31, 2023  
Oregon General Rate Case - December 2023  
ENERGY

		FORECAST LOADS (MWh)								
		Non-FERC						FERC		
Year	Month	CA	OR	WA	UT	ID	WY		Total	
2023	Jan	78,390	1,438,180	438,220	2,298,190	309,560	813,290	24,441	5,400,271	
2023	Feb	67,180	1,257,950	370,680	2,036,940	270,310	736,210	23,009	4,762,279	
2023	Mar	68,700	1,298,140	362,940	2,133,840	281,240	802,650	24,250	4,971,760	
2023	Apr	66,270	1,190,510	327,090	2,052,730	277,990	762,420	24,189	4,701,199	
2023	May	71,900	1,181,490	334,590	2,163,970	335,990	765,160	24,073	4,877,173	
2023	Jun	75,680	1,179,260	343,070	2,406,360	416,930	783,120	23,154	5,227,574	
2023	Jul	82,380	1,329,280	397,920	2,803,180	489,470	785,910	25,094	5,913,234	
2023	Aug	78,240	1,311,840	392,590	2,740,080	393,900	820,570	25,399	5,762,619	
2023	Sep	67,140	1,173,020	350,790	2,326,440	310,150	759,100	25,045	5,011,685	
2023	Oct	62,970	1,187,200	361,320	2,185,070	277,630	780,910	25,385	4,880,485	
2023	Nov	66,800	1,289,570	385,440	2,192,300	258,140	779,820	24,930	4,997,000	
2023	Dec	77,510	1,474,010	441,550	2,373,950	302,220	837,470	26,141	5,532,851	
		863,160	15,310,450	4,506,200	27,713,050	3,923,530	9,426,630	295,110	62,038,130	

- (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		Total	
2023	Jan				55,864			22,398	78,262	
2023	Feb				48,407			21,260	69,667	
2023	Mar				76,018			22,559	98,577	
2023	Apr				83,808			22,741	106,548	
2023	May				81,921			22,610	104,531	
2023	Jun				80,771			21,664	102,435	
2023	Jul				85,708			23,098	108,807	
2023	Aug				92,440			23,408	115,848	
2023	Sep				94,556			23,468	118,024	
2023	Oct				96,135			23,815	119,950	
2023	Nov				96,195			23,240	119,434	
2023	Dec				70,963			24,079	95,041	
		-	-	-	962,785	-	-	274,339	1,237,124	

= equals

		LOADS SERVED FROM COMPANY RESOURCES (NPC)								
		Non-FERC						FERC		
Year	Month	CA	OR	WA	UT	ID	WY		Total	
2023	Jan	78,390	1,438,180	438,220	2,242,326	309,560	813,290	2,042	5,322,009	
2023	Feb	67,180	1,257,950	370,680	1,988,533	270,310	736,210	1,750	4,692,613	
2023	Mar	68,700	1,298,140	362,940	2,057,822	281,240	802,650	1,691	4,873,183	
2023	Apr	66,270	1,190,510	327,090	1,968,922	277,990	762,420	1,448	4,594,650	
2023	May	71,900	1,181,490	334,590	2,082,049	335,990	765,160	1,462	4,772,642	
2023	Jun	75,680	1,179,260	343,070	2,325,589	416,930	783,120	1,490	5,125,139	
2023	Jul	82,380	1,329,280	397,920	2,717,472	489,470	785,910	1,996	5,804,428	
2023	Aug	78,240	1,311,840	392,590	2,647,640	393,900	820,570	1,991	5,646,771	
2023	Sep	67,140	1,173,020	350,790	2,231,884	310,150	759,100	1,577	4,893,661	
2023	Oct	62,970	1,187,200	361,320	2,088,935	277,630	780,910	1,570	4,760,535	
2023	Nov	66,800	1,289,570	385,440	2,096,105	258,140	779,820	1,690	4,877,566	
2023	Dec	77,510	1,474,010	441,550	2,302,987	302,220	837,470	2,062	5,437,810	
		863,160	15,310,450	4,506,200	26,750,265	3,923,530	9,426,630	20,771	60,801,006	

+ plus

		Add: Resolute NTUA (UT) - Grossed up for Line Losses								
		Non-FERC						FERC		
Year	Month	CA	OR	WA	UT	ID	WY		Total	
2023	Jan				22,398			-	22,398	
2023	Feb				21,260			-	21,260	
2023	Mar				22,559			-	22,559	
2023	Apr				22,741			-	22,741	
2023	May				22,610			-	22,610	
2023	Jun				21,664			-	21,664	
2023	Jul				23,098			-	23,098	
2023	Aug				23,408			-	23,408	
2023	Sep				23,468			-	23,468	
2023	Oct				23,815			-	23,815	
2023	Nov				23,240			-	23,240	
2023	Dec				24,079			-	24,079	
		-	-	-	274,339	-	-	-	274,339	

= equals

		LOADS FOR JURISDICTIONAL ALLOCATION (MWh)								
		Non-FERC						FERC		
Year	Month	CA	OR	WA	UT	ID	WY		Total	
2023	Jan	78,390	1,438,180	438,220	2,264,725	309,560	813,290	2,042	5,344,407	
2023	Feb	67,180	1,257,950	370,680	2,009,792	270,310	736,210	1,750	4,713,872	
2023	Mar	68,700	1,298,140	362,940	2,080,381	281,240	802,650	1,691	4,895,742	
2023	Apr	66,270	1,190,510	327,090	1,991,663	277,990	762,420	1,448	4,617,391	
2023	May	71,900	1,181,490	334,590	2,104,660	335,990	765,160	1,462	4,795,252	
2023	Jun	75,680	1,179,260	343,070	2,347,253	416,930	783,120	1,490	5,146,803	
2023	Jul	82,380	1,329,280	397,920	2,740,570	489,470	785,910	1,996	5,827,526	
2023	Aug	78,240	1,311,840	392,590	2,671,048	393,900	820,570	1,991	5,670,179	
2023	Sep	67,140	1,173,020	350,790	2,255,352	310,150	759,100	1,577	4,917,129	
2023	Oct	62,970	1,187,200	361,320	2,112,749	277,630	780,910	1,570	4,784,349	
2023	Nov	66,800	1,289,570	385,440	2,119,345	258,140	779,820	1,690	4,900,805	
2023	Dec	77,510	1,474,010	441,550	2,327,066	302,220	837,470	2,062	5,461,888	
		863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345	

**Pro Forma Factors December 31, 2023  
Oregon General Rate Case - December 2023**

	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC	
Subtotal	863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	<b>61,075,345 Ref Page 10.15</b>
System Energy Factor	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	100.00%
Divisional Energy - Pacific	3.0320%	53.7809%	15.8289%	0.0000%	0.0000%	27.3581%	0.0000%	100.00%
Divisional Energy - Utah	0.0000%	0.0000%	0.0000%	82.8793%	12.0327%	5.0243%	0.0637%	100.00%
System Generation Factor	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	100.00%
Divisional Generation - Pacific	3.1128%	55.3072%	16.6300%	0.0000%	0.0000%	24.9499%	0.0000%	100.00%
Divisional Generation - Utah	0.0000%	0.0000%	0.0000%	83.9816%	11.3613%	4.6017%	0.0554%	100.00%
System Capacity (kw)								
Accord	1,531.2	27,219.8	8,239.4	45,816.4	6,047.7	14,205.1	28.5	<b>103,088 Ref Page 10.14</b>
Modified Accord	1,531.2	27,219.8	8,239.4	45,816.4	6,047.7	14,205.1	28.5	<b>103,088 Ref Page 10.14</b>
Rolled-In	1,531.2	27,219.8	8,239.4	45,816.4	6,047.7	14,205.1	28.5	<b>103,088 Ref Page 10.14</b>
Rolled-In with Hydro Adj.	1,531.2	27,219.8	8,239.4	45,816.4	6,047.7	14,205.1	28.5	<b>103,088 Ref Page 10.14</b>
Rolled-In with Off-Sys Adj.	1,531.2	27,219.8	8,239.4	45,816.4	6,047.7	14,205.1	28.5	<b>103,088 Ref Page 10.14</b>
System Capacity Factor								
Accord	1.4853%	26.4044%	7.9926%	44.4439%	5.8665%	13.7796%	0.0277%	100.00%
Modified Accord	1.4853%	26.4044%	7.9926%	44.4439%	5.8665%	13.7796%	0.0277%	100.00%
Rolled-In	1.4853%	26.4044%	7.9926%	44.4439%	5.8665%	13.7796%	0.0277%	100.00%
Rolled-In with Hydro Adj.	1.4853%	26.4044%	7.9926%	44.4439%	5.8665%	13.7796%	0.0277%	100.00%
Rolled-In with Off-Sys Adj.	1.4853%	26.4044%	7.9926%	44.4439%	5.8665%	13.7796%	0.0277%	100.00%
System Energy (kwh)								
Accord	863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345
Modified Accord	863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345
Rolled-In	863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345
Rolled-In with Hydro Adj.	863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345
Rolled-In with Off-Sys Adj.	863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345
System Energy Factor								
Accord	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	100.00%
Modified Accord	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	100.00%
Rolled-In	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	100.00%
Rolled-In with Hydro Adj.	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	100.00%
Rolled-In with Off-Sys Adj.	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	100.00%
System Generation Factor								
Accord	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	100.00%
Modified Accord	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	100.00%
Rolled-In	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	100.00%
Rolled-In with Hydro Adj.	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	100.00%
Rolled-In with Off-Sys Adj.	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	100.00%



# **B1. REVENUE**



Electric Operations Revenue (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other	
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	CA	49,219	49,219	-	-	-	-	-	
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	IDU	83,945	-	-	-	-	83,945	-	
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	OR	644,819	-	644,819	-	-	-	-	
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	UT	840,427	-	-	-	840,427	-	-	
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WA	150,855	-	-	150,855	-	-	-	
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WYP	98,999	-	-	-	98,999	-	-	
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WYU	12,567	-	-	-	12,567	-	-	
4401000	RESIDENTIAL SALES	301106	Residential-Alt Revenue Program Adjs	WA	8,093	-	-	8,093	-	-	-	
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	CA	(611)	(611)	-	-	-	-	-	
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	IDU	(378)	-	-	-	-	(378)	-	
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	OR	(2,553)	-	(2,553)	-	-	-	-	
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	UT	58,492	-	-	-	-	58,492	-	
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	WA	(2,550)	-	-	(2,550)	-	-	-	
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	WYP	(337)	-	-	-	(337)	-	-	
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	UT	6,589	-	-	-	-	6,589	-	
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	WA	56	-	-	56	-	-	-	
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	WYP	(102)	-	-	-	(102)	-	-	
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	CA	(54)	(54)	-	-	-	-	-	
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	IDU	852	-	-	-	-	852	-	
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	OR	(1,454)	-	(1,454)	-	-	-	-	
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	UT	17,585	-	-	-	-	17,585	-	
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WA	(1,665)	-	-	(1,665)	-	-	-	
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WYP	(1,275)	-	-	-	(1,275)	-	-	
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WYU	911	-	-	-	911	-	-	
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	CA	1,239	1,239	-	-	-	-	-	
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	IDU	109	-	-	-	-	109	-	
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	OR	18,778	-	18,778	-	-	-	-	
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	UT	1,133	-	-	-	-	1,133	-	
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	WA	445	-	-	445	-	-	-	
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	WYP	34	-	-	-	-	34	-	
4401000	RESIDENTIAL SALES	301111	Residential-OR Corp Act Tax Rev Adj	OTHER	2,761	-	-	-	-	-	2,761	
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	OR	(716)	-	(716)	-	-	-	-	
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	UT	(1,449)	-	-	-	(1,449)	-	-	
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	WA	(70)	-	-	(70)	-	-	-	
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	CA	1	1	-	-	-	-	-	
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	IDU	(11)	-	-	-	-	(11)	-	
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	OR	(31)	-	(31)	-	-	-	-	
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	UT	(111)	-	-	-	(111)	-	-	
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	WA	(1)	-	-	(1)	-	-	-	
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	WYP	(13)	-	-	-	(13)	-	-	
4401000	RESIDENTIAL SALES	301165	Solar Feed-In Revenue - Residential	OTHER	3,744	-	-	-	-	-	3,744	
4401000	RESIDENTIAL SALES	301168	Community Solar Revenue-Residential	OTHER	234	-	-	-	-	-	234	
4401000	RESIDENTIAL SALES	301170	DSM Revenue - Residential	OTHER	37,173	-	-	-	-	-	37,173	
4401000	RESIDENTIAL SALES	301171	DSM Revenue - Residential Cat 2 Gen Svc	OTHER	23	-	-	-	-	-	23	
4401000	RESIDENTIAL SALES	301180	Blue Sky Revenue Residential	OTHER	7,078	-	-	-	-	-	7,078	
4401000	RESIDENTIAL SALES	301190	Other Cust Retail Revenue-Residential	OTHER	62	-	-	-	-	-	62	
<b>4401000 Total</b>					<b>2,032,842</b>	<b>49,794</b>	<b>658,843</b>	<b>155,162</b>	<b>110,785</b>	<b>922,667</b>	<b>84,518</b>	<b>51,074</b>
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	CA	31,198	31,198	-	-	-	-	-	
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	IDU	46,072	-	-	-	-	46,072	-	
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	OR	468,560	-	468,560	-	-	-	-	
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	UT	731,595	-	-	-	-	731,595	-	
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WA	122,804	-	-	122,804	-	-	-	
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WYP	104,280	-	-	-	104,280	-	-	
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WYU	10,692	-	-	-	10,692	-	-	
4421000	COMMERCIAL SALES	301206	Commercial-Alt Revenue Program Adjs	WA	4,909	-	-	4,909	-	-	-	
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	CA	(350)	(350)	-	-	-	-	-	
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	IDU	(235)	-	-	-	-	(235)	-	
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	OR	1,031	-	1,031	-	-	-	-	
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	UT	63,733	-	-	-	-	63,733	-	
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	WA	(3,432)	-	-	(3,432)	-	-	-	
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	WYP	(549)	-	-	-	(549)	-	-	
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	UT	8,013	-	-	-	-	8,013	-	
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	WA	53	-	-	53	-	-	-	
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	WYP	(136)	-	-	-	(136)	-	-	
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	CA	(508)	(508)	-	-	-	-	-	
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	IDU	(61)	-	-	-	-	(61)	-	
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	OR	9,873	-	9,873	-	-	-	-	
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	UT	9,650	-	-	-	-	9,650	-	
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WA	1,276	-	-	1,276	-	-	-	
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WYP	(1,047)	-	-	-	(1,047)	-	-	
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WYU	61	-	-	-	61	-	-	
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	CA	788	788	-	-	-	-	-	
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	IDU	75	-	-	-	-	75	-	



Electric Operations Revenue (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	OR	17,786	-	17,786	-	-	-	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	UT	1,446	-	-	-	1,446	-	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	WA	412	-	-	412	-	-	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	WYP	46	-	-	-	46	-	-	-
4421000	COMMERCIAL SALES	301211	Commercial-OR Corp Act Tax Alt Rev Adj	OTHER	1,986	-	-	-	-	-	-	1,986
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	OR	(80)	-	(80)	-	-	-	-	-
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	UT	(100)	-	-	-	-	(100)	-	-
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	WA	(14)	-	-	(14)	-	-	-	-
4421000	COMMERCIAL SALES	301265	Solar Feed-In Revenue - Commercial	OTHER	3,876	-	-	-	-	-	-	3,876
4421000	COMMERCIAL SALES	301268	Community Solar Revenue-Commercial	OTHER	170	-	-	-	-	-	-	170
4421000	COMMERCIAL SALES	301270	DSM Revenue - Commercial	OTHER	25,628	-	-	-	-	-	-	25,628
4421000	COMMERCIAL SALES	301271	DSM Revenue - Small Commercial	OTHER	1,401	-	-	-	-	-	-	1,401
4421000	COMMERCIAL SALES	301272	DSM Revenue - Large Commercial	OTHER	75	-	-	-	-	-	-	75
4421000	COMMERCIAL SALES	301280	Blue Sky Revenue - Commercial	OTHER	2,343	-	-	-	-	-	-	2,343
4421000	COMMERCIAL SALES	301290	Other Cust Retail Revenue-Commercial	OTHER	81	-	-	-	-	-	-	81
<b>4421000 Total</b>					<b>1,663,402</b>	<b>31,128</b>	<b>497,170</b>	<b>126,008</b>	<b>113,348</b>	<b>814,337</b>	<b>45,851</b>	<b>35,560</b>
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	CA	5,530	5,530	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	IDU	12,866	-	-	-	-	12,866	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	OR	109,707	-	109,707	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	UT	326,520	-	-	-	-	326,520	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WA	54,593	-	54,593	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WYP	303,636	-	-	303,636	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WYU	65,983	-	-	65,983	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301304	SPECIAL CONTRACTS-SITUS	IDU	98,623	-	-	-	-	-	98,623	-
4422000	IND SLS/EXCL IRRIG	301304	SPECIAL CONTRACTS-SITUS	UT	122,915	-	-	-	-	122,915	-	-
4422000	IND SLS/EXCL IRRIG	301306	Industrial-Alt Revenue Program Adjs	WA	(1,642)	-	(1,642)	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	CA	(57)	(57)	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	IDU	(418)	-	-	-	-	(418)	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	OR	(485)	-	(485)	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	UT	64,345	-	-	-	-	64,345	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	WA	936	-	936	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	WYP	(3,175)	-	-	(3,175)	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	UT	7,216	-	-	-	-	7,216	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	WA	27	-	27	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	WYP	(652)	-	-	(652)	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	CA	(8)	(8)	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	IDU	(3,426)	-	-	-	-	(3,426)	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	OR	1,390	-	1,390	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	UT	11,670	-	-	-	-	11,670	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WA	17	-	17	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WYP	3,767	-	-	3,767	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WYU	1,925	-	-	1,925	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	CA	189	189	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	IDU	245	-	-	-	-	245	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	OR	5,575	-	5,575	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	UT	1,279	-	-	-	-	1,279	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	WA	134	-	134	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	WYP	233	-	-	233	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301311	Industrial-OR Corp Act Tax Rev Adj	OTHER	466	-	-	-	-	-	-	466
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	OR	(5)	-	(5)	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	UT	(32)	-	-	-	-	(32)	-	-
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	WA	(4)	-	(4)	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301365	Solar Feed-In Revenue - Industrial	OTHER	2,241	-	-	-	-	-	-	2,241
4422000	IND SLS/EXCL IRRIG	301368	Community Solar Revenue-Industrial	OTHER	47	-	-	-	-	-	-	47
4422000	IND SLS/EXCL IRRIG	301370	DSM Revenue - Industrial	OTHER	10,533	-	-	-	-	-	-	10,533
4422000	IND SLS/EXCL IRRIG	301371	DSM Revenue - Small Industrial	OTHER	323	-	-	-	-	-	-	323
4422000	IND SLS/EXCL IRRIG	301372	DSM Revenue - Large Industrial	OTHER	1,994	-	-	-	-	-	-	1,994
4422000	IND SLS/EXCL IRRIG	301380	Blue Sky Revenue - Industrial	OTHER	842	-	-	-	-	-	-	842
4422000	IND SLS/EXCL IRRIG	301390	Other Cust Retail Revenue-Industrial	OTHER	26	-	-	-	-	-	-	26
<b>4422000 Total</b>					<b>1,205,885</b>	<b>5,654</b>	<b>116,182</b>	<b>54,060</b>	<b>371,716</b>	<b>533,913</b>	<b>107,889</b>	<b>16,471</b>
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	CA	14,463	14,463	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	IDU	62,030	-	-	-	-	62,030	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	OR	28,017	-	28,017	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	UT	21,631	-	-	-	-	21,631	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WA	15,395	-	15,395	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WYP	2,105	-	-	2,105	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WYU	642	-	-	642	-	-	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	OR	(3)	-	(3)	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	UT	(1)	-	-	-	-	(1)	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	WA	(3)	-	-	(3)	-	-	-	-
4423000	INDUST SALES-IRRIG	301454	Irrigation-OR Corp Act Tax Rev Adj	OTHER	121	-	-	-	-	-	-	121
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	CA	312	312	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	IDU	94	-	-	-	-	94	-	-



Electric Operations Revenue (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other	
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	OR	1,001	-	1,001	-	-	-	-	
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	UT	33	-	-	-	33	-	-	
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	WA	24	-	-	24	-	-	-	
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	WYP	1	-	-	-	1	-	-	
4423000	INDUST SALES-IRRIG	301456	Irrigation-Alt Revenue Program Adjs	WA	(1,411)	-	-	(1,411)	-	-	-	
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	CA	(159)	(159)	-	-	-	-	-	
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	IDU	(297)	-	-	-	(297)	-	-	
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	OR	(75)	-	(75)	-	-	-	-	
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	UT	4,613	-	-	-	4,613	-	-	
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	WA	90	-	-	90	-	-	-	
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	WYP	(8)	-	-	-	(8)	-	-	
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	UT	244	-	-	-	244	-	-	
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	WA	6	-	-	6	-	-	-	
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	WYP	(3)	-	-	-	(3)	-	-	
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	CA	447	447	-	-	-	-	-	
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	IDU	6,653	-	-	-	-	6,653	-	
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	OR	1,205	-	1,205	-	-	-	-	
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	UT	702	-	-	-	702	-	-	
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WA	776	-	-	776	-	-	-	
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WYP	168	-	-	-	168	-	-	
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WYU	24	-	-	-	24	-	-	
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Chrg	CA	24	24	-	-	-	-	-	
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Chrg	OR	193	-	193	-	-	-	-	
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Chrg	WA	(66)	-	-	(66)	-	-	-	
4423000	INDUST SALES-IRRIG	301465	Solar Feed-In Revenue - Irrigation	OTHER	119	-	-	-	-	-	119	
4423000	INDUST SALES-IRRIG	301468	Community Solar Revenue-Irrigation	OTHER	8	-	-	-	-	-	8	
4423000	INDUST SALES-IRRIG	301470	DSM Revenue - Irrigation	OTHER	3,315	-	-	-	-	-	3,315	
4423000	INDUST SALES-IRRIG	301480	Blue Sky Revenue - Irrigation	OTHER	4	-	-	-	-	-	4	
4423000	INDUST SALES-IRRIG	301490	Other Cust Retail Revenue-Irrigation	OTHER	7	-	-	-	-	-	7	
<b>4423000 Total</b>					<b>162,438</b>	<b>15,087</b>	<b>30,338</b>	<b>14,811</b>	<b>2,929</b>	<b>27,221</b>	<b>68,479</b>	<b>3,573</b>
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	CA	356	356	-	-	-	-	-	
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	IDU	538	-	-	-	-	538	-	
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	OR	5,730	-	5,730	-	-	-	-	
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	UT	7,041	-	-	-	7,041	-	-	
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WA	724	-	-	724	-	-	-	
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WYP	1,533	-	-	-	1,533	-	-	
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WYU	334	-	-	-	334	-	-	
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	(12)	-	(12)	-	-	-	-	
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	UT	487	-	-	-	487	-	-	
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	WA	(18)	-	-	(18)	-	-	-	
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	WYU	(4)	-	-	-	(4)	-	-	
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	UT	59	-	-	-	59	-	-	
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	WYP	(1)	-	-	-	(1)	-	-	
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	CA	(2)	(2)	-	-	-	-	-	
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	IDU	(6)	-	-	-	-	(6)	-	
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	OR	(41)	-	(41)	-	-	-	-	
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	UT	(98)	-	-	-	(98)	-	-	
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WA	15	-	-	15	-	-	-	
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WYP	(3)	-	-	-	(3)	-	-	
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WYU	20	-	-	-	20	-	-	
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	CA	6	6	-	-	-	-	-	
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	IDU	0	-	-	-	-	0	-	
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	OR	130	-	130	-	-	-	-	
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	UT	10	-	-	-	10	-	-	
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	WA	3	-	-	3	-	-	-	
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	WYP	0	-	-	-	0	-	-	
4441000	PUB ST/HWY LIGHT	301611	St&Hwy Light-OR Corp Act Tax Rev Adj	OTHER	25	-	-	-	-	-	25	
4441000	PUB ST/HWY LIGHT	301612	St&Hwy Light - Customer Bill Credits	OR	(1)	-	(1)	-	-	-	-	
4441000	PUB ST/HWY LIGHT	301612	St&Hwy Light - Customer Bill Credits	UT	(0)	-	-	-	(0)	-	-	
4441000	PUB ST/HWY LIGHT	301612	St&Hwy Light - Customer Bill Credits	WA	(27)	-	-	(27)	-	-	-	
4441000	PUB ST/HWY LIGHT	301665	Solar Feed-In Revenue - St/Hwy Lighting	OTHER	26	-	-	-	-	-	26	
4441000	PUB ST/HWY LIGHT	301668	Community Solar Revenue-St/Hwy Lightg	OTHER	1	-	-	-	-	-	1	
4441000	PUB ST/HWY LIGHT	301670	DSM Revenue - Street/Hwy Lighting	OTHER	247	-	-	-	-	-	247	
4441000	PUB ST/HWY LIGHT	301690	Other Cust Retail Revenue-St/Hwy Lightg	OTHER	0	-	-	-	-	-	0	
<b>4441000 Total</b>					<b>17,065</b>	<b>356</b>	<b>5,807</b>	<b>697</b>	<b>1,880</b>	<b>7,498</b>	<b>530</b>	<b>299</b>
4471000	ON-SYS WHOLE-FIRM	301443	ON SYS FIRM-UTAH FERC CUSTOMERS	FERC	12,376	-	-	-	-	-	12,376	
4471000	ON-SYS WHOLE-FIRM	301445	On Sys Firm-Utah W/S Customers-Deferral	UT	(60)	-	-	-	(60)	-	-	
<b>4471000 Total</b>					<b>12,316</b>	-	-	-	<b>(60)</b>	-	<b>12,376</b>	
4471300	POST MERGER FIRM	301405	POST MERGER FIRM	SG	7,377	108	1,923	578	1,047	443	2	
<b>4471300 Total</b>					<b>7,377</b>	<b>108</b>	<b>1,923</b>	<b>578</b>	<b>1,047</b>	<b>3,275</b>	<b>443</b>	<b>2</b>
4471400	S/T FIRM WHOLESALE	301406	SHORT-TERM FIRM WHOLESALE SALES	SG	277,598	4,073	72,371	21,761	39,400	123,239	16,672	81



Electric Operations Revenue (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
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Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other	
4471400	S/T FIRM WHOLESale	301409	TRADING SALES NETTED-EST.	SG	64	1	17	5	9	29	4	0
4471400	S/T FIRM WHOLESale	301410	TRADING SALES NETTED	SG	(803)	(12)	(209)	(63)	(114)	(356)	(48)	(0)
4471400	S/T FIRM WHOLESale	301411	BOOKOUT SALES NETTED	SG	(105,787)	(1,552)	(27,579)	(8,293)	(15,015)	(46,964)	(6,353)	(31)
4471400	S/T FIRM WHOLESale	301412	BOOKOUT SALES NETTED-ESTIMATE	SG	1,731	25	451	136	246	768	104	1
4471400	S/T FIRM WHOLESale	302751	I/C S-T Firm Wholesale Sales-Sierra Pac	SG	28	0	7	2	4	12	2	0
4471400	S/T FIRM WHOLESale	302752	I/C S-T Firm Wholesale Sales-Nevada Pwr	SG	921	14	240	72	131	409	55	0
4471400	S/T FIRM WHOLESale	303028	LINE LOSS W/S TRADING REVENUES	SG	7,473	110	1,948	586	1,061	3,318	449	2
<b>4471400 Total</b>					<b>181,226</b>	<b>2,659</b>	<b>47,246</b>	<b>14,206</b>	<b>25,722</b>	<b>80,455</b>	<b>10,884</b>	<b>53</b>
4472000	SLS FOR RESL-SURP	301419	ESTIMATED SALES FOR RESALE REVENUE	SG	(341)	(5)	(89)	(27)	(48)	(151)	(20)	(0)
4472000	SLS FOR RESL-SURP	302762	I/C Wholesale Sales Estimate-Nevada Pwr	SG	17	0	4	1	2	7	1	0
4472000	SLS FOR RESL-SURP	303198	Non-ASC 606-WS NPC Rev-Derivativ (Disc)	SG	52,642	772	13,724	4,127	7,472	23,370	3,162	15
4472000	SLS FOR RESL-SURP	303199	Non-ASC 606-WS NPC Rev-Derivativ (Recl)	SG	(52,642)	(772)	(13,724)	(4,127)	(7,472)	(23,370)	(3,162)	(15)
<b>4472000 Total</b>					<b>(324)</b>	<b>(5)</b>	<b>(85)</b>	<b>(25)</b>	<b>(46)</b>	<b>(144)</b>	<b>(19)</b>	<b>(0)</b>
4475000	OFF-SYS - NON FIRM	301408	OFF-SYSTEM WHOLESale - NON FIRM	SE	(3,707)	(52)	(929)	(274)	(572)	(1,640)	(238)	(1)
<b>4475000 Total</b>					<b>(3,707)</b>	<b>(52)</b>	<b>(929)</b>	<b>(274)</b>	<b>(572)</b>	<b>(1,640)</b>	<b>(238)</b>	<b>(1)</b>
4476100	BOOKOUTS NETTED-GAIN	304101	BOOKOUTS NETTED-GAIN	SG	15,242	224	3,974	1,195	2,163	6,767	915	4
<b>4476100 Total</b>					<b>15,242</b>	<b>224</b>	<b>3,974</b>	<b>1,195</b>	<b>2,163</b>	<b>6,767</b>	<b>915</b>	<b>4</b>
4476200	TRADING NETTED-GAINS	304201	TRADING NETTED-GAINS	SG	62	1	16	5	9	28	4	0
<b>4476200 Total</b>					<b>62</b>	<b>1</b>	<b>16</b>	<b>5</b>	<b>9</b>	<b>28</b>	<b>4</b>	<b>0</b>
4479000	TRANS SRVC	301428	TRANS SERV-UTAH FERC CUSTOMERS	FERC	125	-	-	-	-	-	-	125
<b>4479000 Total</b>					<b>125</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>125</b>
4491800	PRV RTE RFDS-RESLE	301975	Wholesales Sales - Subject to Refund	SG	(3,240)	(48)	(845)	(254)	(460)	(1,438)	(195)	(1)
<b>4491800 Total</b>					<b>(3,240)</b>	<b>(48)</b>	<b>(845)</b>	<b>(254)</b>	<b>(460)</b>	<b>(1,438)</b>	<b>(195)</b>	<b>(1)</b>
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	CA	(0)	(0)	-	-	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	IDU	286	-	-	-	-	-	286	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	OR	(8)	-	(8)	-	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	UT	3,696	-	-	-	-	3,696	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WA	(2)	-	-	(2)	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WYP	633	-	-	-	633	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WYU	69	-	-	-	69	-	-	-
<b>4501000 Total</b>					<b>4,672</b>	<b>(0)</b>	<b>(8)</b>	<b>(2)</b>	<b>702</b>	<b>3,696</b>	<b>286</b>	<b>-</b>
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	CA	(0)	(0)	-	-	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	IDU	32	-	-	-	-	-	32	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	OR	(2)	-	(2)	-	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	UT	940	-	-	-	-	940	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WA	(0)	-	-	(0)	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WYP	124	-	-	-	124	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WYU	17	-	-	-	17	-	-	-
<b>4502000 Total</b>					<b>1,111</b>	<b>(0)</b>	<b>(2)</b>	<b>(0)</b>	<b>141</b>	<b>940</b>	<b>32</b>	<b>-</b>
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	IDU	136	-	-	-	-	-	136	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	OR	(0)	-	(0)	-	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	UT	323	-	-	-	-	323	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WA	(0)	-	-	(0)	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WYP	71	-	-	-	71	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WYU	171	-	-	-	171	-	-	-
<b>4503000 Total</b>					<b>701</b>	<b>-</b>	<b>(0)</b>	<b>(0)</b>	<b>242</b>	<b>323</b>	<b>136</b>	<b>-</b>
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	IDU	6	-	-	-	-	-	6	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	OR	(9)	-	(9)	-	-	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	UT	116	-	-	-	-	116	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	WYP	4	-	-	-	4	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	WYU	0	-	-	-	0	-	-	-
<b>4504000 Total</b>					<b>116</b>	<b>-</b>	<b>(9)</b>	<b>-</b>	<b>4</b>	<b>116</b>	<b>6</b>	<b>-</b>
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	CA	423	423	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	IDU	53	-	-	-	-	-	53	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	OR	971	-	971	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	UT	3,462	-	-	-	-	3,462	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WA	43	-	-	43	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WYP	91	-	-	-	91	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WYU	6	-	-	-	6	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	CA	8	8	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	IDU	33	-	-	-	-	-	33	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	OR	178	-	178	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	UT	405	-	-	-	-	405	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WA	41	-	-	41	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WYP	77	-	-	-	77	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WYU	8	-	-	-	8	-	-	-
<b>4511000 Total</b>					<b>5,800</b>	<b>431</b>	<b>1,149</b>	<b>85</b>	<b>182</b>	<b>3,867</b>	<b>87</b>	<b>-</b>
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	CA	(1)	(1)	-	-	-	-	-	-
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	IDU	(4)	-	-	-	-	-	(4)	-
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	OR	(32)	-	(32)	-	-	-	-	-
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	UT	(53)	-	-	-	-	(53)	-	-
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	WA	(6)	-	-	(6)	-	-	-	-



Electric Operations Revenue (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	WYP	(5)	-	-	(5)	-	-	-
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	WYU	(1)	-	-	(1)	-	-	-
<b>4511500 Total</b>					<b>(102)</b>	<b>(1)</b>	<b>(32)</b>	<b>(6)</b>	<b>(53)</b>	<b>(4)</b>	<b>-</b>
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHG	CA	0	0	-	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHG	OR	4	-	4	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHG	SO	0	0	0	0	0	0	0
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHG	UT	1	-	-	-	1	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHG	WA	0	-	0	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHG	WYP	0	-	-	0	-	-	-
<b>4512000 Total</b>					<b>6</b>	<b>0</b>	<b>4</b>	<b>0</b>	<b>1</b>	<b>0</b>	<b>0</b>
4513000	OTHER	301828	OTHER	CA	43	43	-	-	-	-	-
4513000	OTHER	301828	OTHER	IDU	18	-	-	-	-	18	-
4513000	OTHER	301828	OTHER	OR	412	-	412	-	-	-	-
4513000	OTHER	301828	OTHER	SO	52	1	14	4	7	23	3
4513000	OTHER	301828	OTHER	UT	715	-	-	-	715	-	-
4513000	OTHER	301828	OTHER	WA	380	-	-	380	-	-	-
4513000	OTHER	301828	OTHER	WYP	185	-	-	-	185	-	-
4513000	OTHER	301828	OTHER	WYU	10	-	-	-	10	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	CA	7	7	-	-	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	IDU	22	-	-	-	-	22	-
4513000	OTHER	301840	Miscellaneous Service Revenue	OR	13	-	13	-	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	UT	663	-	-	-	-	663	-
4513000	OTHER	301840	Miscellaneous Service Revenue	WA	40	-	-	40	-	-	-
<b>4513000 Total</b>					<b>2,559</b>	<b>51</b>	<b>439</b>	<b>424</b>	<b>202</b>	<b>1,400</b>	<b>42</b>
4514100	ENERGY FINANSWER	301836	ENERGY FINAN - NEW COMM	UT	0	-	-	-	-	0	-
<b>4514100 Total</b>					<b>0</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>0</b>	<b>-</b>
4530000	SLS WATER & W PWR	358900	Sales of Water & Water Power	SG	7	0	2	1	1	3	0
<b>4530000 Total</b>					<b>7</b>	<b>0</b>	<b>2</b>	<b>1</b>	<b>1</b>	<b>3</b>	<b>0</b>
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	CA	3	3	-	-	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	IDU	1	-	-	-	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	OR	861	-	861	-	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	SG	901	13	235	71	128	400	54
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	SO	2,540	56	690	195	334	1,116	148
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	UT	1,364	-	-	-	-	1,364	-
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	301860	RENT FROM ELEC PROP	WYU	18	-	-	-	18	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	CA	483	483	-	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	IDU	164	-	-	-	-	164	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	OR	2,856	-	2,856	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	UT	1,976	-	-	-	-	1,976	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	WA	691	-	-	691	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	WYP	324	-	-	-	324	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	OR	3	-	3	-	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	SG	2	0	0	0	1	0	0
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	UT	1	-	-	-	1	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	WA	0	-	0	-	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	WYP	5	-	-	-	5	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	CA	8	8	-	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	IDU	0	-	-	-	-	0	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	OR	234	-	234	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	UT	254	-	-	-	-	254	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	WA	48	-	-	48	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	WYP	10	-	-	-	10	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	CA	4	4	-	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	IDU	(0)	-	-	-	-	(0)	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	OR	(60)	-	(60)	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	UT	(6)	-	-	-	-	(6)	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	WA	(4)	-	-	(4)	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	WYP	(1)	-	-	-	-	(1)	-
4541000	RENTS - COMMON	301870	RENT REV - STEAM	SG	4	0	1	0	2	0	0
4541000	RENTS - COMMON	301872	RENT REV - TRANS	SG	468	7	122	37	66	208	28
4541000	RENTS - COMMON	301873	RENT REV - DIST	SO	0	0	0	0	0	0	0
4541000	RENTS - COMMON	301874	RENT REV - GENERAL	SG	13	0	3	1	2	6	1
4541000	RENTS - COMMON	301874	RENT REV - GENERAL	SO	3	0	3	0	1	0	0
4541000	RENTS - COMMON	301878	JOINT USE BACK RENT	OR	1	-	1	0	0	1	0
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburse	CA	34	34	-	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburse	IDU	5	-	-	-	-	5	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburse	OR	712	-	712	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburse	UT	51	-	-	-	-	51	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburse	WA	159	-	-	159	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburse	WYP	11	-	-	-	11	-	-
4541000	RENTS - COMMON	301885	RENT REVENUE - SUBLE	SO	599	13	163	46	79	263	35



Electric Operations Revenue (Actuals)  
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Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other	
4541000	RENTS - COMMON	301886	Rent Revenue - Subleases - Operating	SG	116	2	30	9	17	52	7	0
<b>4541000 Total</b>					<b>14,882</b>	<b>623</b>	<b>5,853</b>	<b>1,263</b>	<b>1,010</b>	<b>5,688</b>	<b>444</b>	<b>1</b>
4543000	MCI FOGWIRE REVENUES	301863	MCI FIBER OPTIC GROUND WIRE REVENUES	SG	3,355	49	875	263	476	1,489	201	1
<b>4543000 Total</b>					<b>3,355</b>	<b>49</b>	<b>875</b>	<b>263</b>	<b>476</b>	<b>1,489</b>	<b>201</b>	<b>1</b>
4545000	VERT BRIDGE REVENUES	367222	Joint Use - Vertical Bridge Applic Fee	SG	9	0	2	1	1	4	1	0
<b>4545000 Total</b>					<b>9</b>	<b>0</b>	<b>2</b>	<b>1</b>	<b>1</b>	<b>4</b>	<b>1</b>	<b>0</b>
4561100	Other Wheeling Rev	301953	Ancillary Rev Sch 6-Supp (C&T)	SG	2,158	32	563	169	306	958	130	1
4561100	Other Wheeling Rev	301963	Ancil Revenue Sch 2-Reactive (C&T)	SG	2,316	34	604	182	329	1,028	139	1
4561100	Other Wheeling Rev	301966	Primary Delivery and Distribution Sub Ch	SG	418	6	109	33	59	186	25	0
4561100	Other Wheeling Rev	301967	Ancillary Revenue Sch 1 - Scheduling	SG	2,694	40	702	211	382	1,196	162	1
4561100	Other Wheeling Rev	301969	Ancillary Revenue Sch 3 - Reg&Freq (C&T)	SG	2,356	35	614	185	334	1,046	142	1
4561100	Other Wheeling Rev	301973	Ancillary Revenue Sch 5&6-Spin&Supp (C&T)	SG	2,118	31	552	166	301	940	127	1
4561100	Other Wheeling Rev	301974	Ancil Revenue Sch 3a-Regulation (C&T)	SG	4,430	65	1,155	347	629	1,967	266	1
4561100	Other Wheeling Rev	302082	I/C Anc Rev Sch 1-Scheduling-Nevada Pwr	SG	0	0	0	0	0	0	0	0
4561100	Other Wheeling Rev	302092	I/C Anc Rev Sch 2-Reactive-Nevada Pwr	SG	0	0	0	0	0	0	0	0
4561100	Other Wheeling Rev	302831	I/C Other Wheeling Revenue-Sierra Pac	SG	33	0	9	3	5	15	2	0
4561100	Other Wheeling Rev	302901	USE OF FACILITY REVENUE	SG	721	11	188	57	102	320	43	0
4561100	Other Wheeling Rev	302982	Transmission Rev-Unreserved Use Charges	SG	466	7	122	37	66	207	28	0
4561100	Other Wheeling Rev	302983	Transmission Revenue - Deferral Fees	SG	352	5	92	28	50	156	21	0
<b>4561100 Total</b>					<b>18,065</b>	<b>265</b>	<b>4,710</b>	<b>1,416</b>	<b>2,564</b>	<b>8,020</b>	<b>1,085</b>	<b>5</b>
4561910	S/T FIRM WHEEL REV	301926	SHORT TERM FIRM WHEELING	SG	3,177	47	828	249	451	1,410	191	1
<b>4561910 Total</b>					<b>3,177</b>	<b>47</b>	<b>828</b>	<b>249</b>	<b>451</b>	<b>1,410</b>	<b>191</b>	<b>1</b>
4561920	LT FIRM WHEEL REV	301912	POST-MERGER FIRM WHEELING	SG	15,441	227	4,026	1,210	2,192	6,855	927	5
4561920	LT FIRM WHEEL REV	301916	PRE-MERGER FIRM WHEELING	SG	7,434	109	1,938	583	1,055	3,300	446	2
4561920	LT FIRM WHEEL REV	301917	PRE-MERGER FIRM WHEELING	SG	24,715	363	6,443	1,937	3,508	10,972	1,484	7
4561920	LT FIRM WHEEL REV	302980	Transmission Point-to-Point Revenue	SG	38,959	572	10,157	3,054	5,530	17,296	2,340	11
<b>4561920 Total</b>					<b>86,548</b>	<b>1,270</b>	<b>22,563</b>	<b>6,784</b>	<b>12,284</b>	<b>38,423</b>	<b>5,198</b>	<b>25</b>
4561930	NON-FIRM WHEEL REV	301922	NON-FIRM WHEELING REVENUE	SE	26,514	375	6,647	1,956	4,092	11,732	1,703	9
4561930	NON-FIRM WHEEL REV	302822	I/C Non-Firm Wheeling Revenue-Nevada Pwr	SE	10	0	2	1	2	4	1	0
<b>4561930 Total</b>					<b>26,524</b>	<b>375</b>	<b>6,649</b>	<b>1,957</b>	<b>4,094</b>	<b>11,736</b>	<b>1,704</b>	<b>9</b>
4561990	TRANSMN REV REFUND	301913	Transmission Tariff True-up	SG	(4,553)	(67)	(1,187)	(357)	(646)	(2,021)	(273)	(1)
<b>4561990 Total</b>					<b>(4,553)</b>	<b>(67)</b>	<b>(1,187)</b>	<b>(357)</b>	<b>(646)</b>	<b>(2,021)</b>	<b>(273)</b>	<b>(1)</b>
4562100	USE OF FACIL REV	301911	"INCOME FROM FISH, WILDLIFE"	SG	19	0	5	1	3	8	1	0
<b>4562100 Total</b>					<b>19</b>	<b>0</b>	<b>5</b>	<b>1</b>	<b>3</b>	<b>8</b>	<b>1</b>	<b>0</b>
4562300	MISC OTHER REV	301900	ELECTRIC INCOME OTHER	SG	2	0	1	0	0	1	0	0
4562300	MISC OTHER REV	301900	ELECTRIC INCOME OTHER	UT	16	-	-	-	-	16	-	-
4562300	MISC OTHER REV	301900	ELECTRIC INCOME OTHER	WYU	0	-	-	0	-	-	-	-
4562300	MISC OTHER REV	301901	WASHINGTON - COLSTRIP 3	WA	(30)	-	-	(30)	-	-	-	-
4562300	MISC OTHER REV	301915	OTHER ELEC REV - MISC	SG	1,476	22	385	116	210	655	89	0
4562300	MISC OTHER REV	301939	Estimated Other Electric Revenue	SG	(16)	(0)	(4)	(1)	(2)	(7)	(1)	(0)
4562300	MISC OTHER REV	301940	FLYASH & BY-PRODUCT SALES	SG	12,187	179	3,177	955	1,730	5,411	732	4
4562300	MISC OTHER REV	301949	THIRD PARTY TRN O&M REV	SG	636	9	166	50	90	282	38	0
4562300	MISC OTHER REV	301951	NON-WHEELING SYS REV	SG	89	1	23	7	13	39	5	0
4562300	MISC OTHER REV	301955	OTHER REV WY REG KENNECOTT	WYP	113	-	-	-	113	-	-	-
4562300	MISC OTHER REV	301958	Wind-based Ancillary Services Estimate	SG	(287)	(4)	(75)	(23)	(41)	(128)	(17)	(0)
4562300	MISC OTHER REV	301959	Wind-based Ancillary Services/Revenue	SG	10,822	159	2,821	848	1,536	4,804	650	3
4562300	MISC OTHER REV	361000	STEAM SALES	SG	168	2	44	13	24	74	10	0
4562300	MISC OTHER REV	374400	Timber Sales - Utility Property	SG	144	2	37	11	20	64	9	0
4562300	MISC OTHER REV	610004	Blank	OTHER	(0)	-	-	-	-	-	-	(0)
4562300	MISC OTHER REV	701010	Labor Costs Settled to Capital	OTHER	0	-	-	-	-	-	-	0
<b>4562300 Total</b>					<b>25,319</b>	<b>370</b>	<b>6,575</b>	<b>1,947</b>	<b>3,693</b>	<b>11,212</b>	<b>1,515</b>	<b>7</b>
4562310	EIM - MISCELLANEOUS	308001	EIM Rev-Forecasting Fee: Pac to TC	SG	15	0	4	1	2	7	1	0
<b>4562310 Total</b>					<b>15</b>	<b>0</b>	<b>4</b>	<b>1</b>	<b>2</b>	<b>7</b>	<b>1</b>	<b>0</b>
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	SG	4	0	1	0	1	2	0	0
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	SO	(2,863)	(63)	(778)	(220)	(376)	(1,258)	(167)	(1)
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	UT	3,319	-	-	-	-	3,319	-	-
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	WYP	75	-	-	-	75	-	-	-
<b>4562400 Total</b>					<b>536</b>	<b>(63)</b>	<b>(777)</b>	<b>(219)</b>	<b>(301)</b>	<b>2,063</b>	<b>(167)</b>	<b>(1)</b>
4562500	M&S INV COST OF SALE	514950	M&S INVENTORY COST OF SALES	UT	(521)	-	-	-	-	(521)	-	-
<b>4562500 Total</b>					<b>(521)</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>(521)</b>	<b>-</b>	<b>-</b>
4562700	RNW ENRGY CRDT SALES	301943	Renewable Energy Credit Sales-Deferral	SG	(2,739)	(40)	(714)	(215)	(389)	(1,216)	(165)	(1)
4562700	RNW ENRGY CRDT SALES	301944	Renewable Energy Credit Sales-Estimate	SG	150	2	39	12	21	66	9	0
4562700	RNW ENRGY CRDT SALES	301945	Renewable Energy Credit Sales	SG	8,884	130	2,316	696	1,261	3,944	534	3
4562700	RNW ENRGY CRDT SALES	352943	Renwbl En Cr Sls-Amt	OTHER	1,225	-	-	-	-	-	-	1,225
4562700	RNW ENRGY CRDT SALES	352950	REC Sales - Wind Wake Loss Indemnity	SG	0	0	0	0	0	0	0	0
4562700	RNW ENRGY CRDT SALES	354945	REC Sales - Blue Sky Program - Actual	OTHER	2,338	-	-	-	-	-	-	2,338
<b>4562700 Total</b>					<b>9,588</b>	<b>92</b>	<b>1,641</b>	<b>493</b>	<b>893</b>	<b>2,795</b>	<b>378</b>	<b>2</b>
4562800	CA GHG Emission Allo	352001	CA GHG Allowance Revenues	OTHER	12,039	-	-	-	-	-	-	12,039
4562800	CA GHG Emission Allo	352002	CA GHG Allowance Revenues - Deferral	OTHER	(12,039)	-	-	-	-	-	-	(12,039)
4562800	CA GHG Emission Allo	352003	CA GHG Allowance Revenues - Amortz	OTHER	7,180	-	-	-	-	-	-	7,180
4562800	CA GHG Emission Allo	352004	CA GHG Allow Revenues - SOMAH Amortz	OTHER	118	-	-	-	-	-	-	118
<b>4562800 Total</b>					<b>7,299</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>7,299</b>



Electric Operations Revenue (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other		
4563500	Oth Elec Rev-Def Trn	305990	FERC Transmission Refund-Deferral	OR	(5,897)	-	(5,897)	-	-	-	-		
4563500	Oth Elec Rev-Def Trn	305991	FERC Transmission Refund-Amortz	OR	31,698	-	31,698	-	-	-	-		
<b>4563500 Total</b>					<b>25,801</b>	<b>-</b>	<b>25,801</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>		
<b>Grand Total</b>					<b>5,521,910</b>	<b>108,348</b>	<b>1,434,724</b>	<b>380,470</b>	<b>654,514</b>	<b>2,483,484</b>	<b>329,923</b>	<b>12,608</b>	<b>117,840</b>



# **B2. O&M EXPENSE**



Operations & Maintenance Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5000000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	14,521	213	3,786	1,138	2,061	6,447	872	4	-
<b>5000000 Total</b>					<b>14,521</b>	<b>213</b>	<b>3,786</b>	<b>1,138</b>	<b>2,061</b>	<b>6,447</b>	<b>872</b>	<b>4</b>	<b>-</b>
5001000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	429	6	112	34	61	190	26	0	-
<b>5001000 Total</b>					<b>429</b>	<b>6</b>	<b>112</b>	<b>34</b>	<b>61</b>	<b>190</b>	<b>26</b>	<b>0</b>	<b>-</b>
5010000	FUEL CONSUMED	NPCX	Net Power Cost Expense	SE	2,910	41	730	215	449	1,288	187	1	-
<b>5010000 Total</b>					<b>2,910</b>	<b>41</b>	<b>730</b>	<b>215</b>	<b>449</b>	<b>1,288</b>	<b>187</b>	<b>1</b>	<b>-</b>
5011000	FUEL CONSUMED-COAL	NPCX	Net Power Cost Expense	SE	648,726	9,168	162,623	47,864	100,127	287,048	41,675	221	-
<b>5011000 Total</b>					<b>648,726</b>	<b>9,168</b>	<b>162,623</b>	<b>47,864</b>	<b>100,127</b>	<b>287,048</b>	<b>41,675</b>	<b>221</b>	<b>-</b>
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	IDU	36	-	-	-	-	-	36	-	-
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	WYP	101	-	-	-	101	-	-	-	-
<b>5011200 Total</b>					<b>137</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>101</b>	<b>-</b>	<b>36</b>	<b>-</b>	<b>-</b>
5011300	FUEL-COAL DC UMWVA PE	STEX	Steam O&M Expense	SE	1,422	20	357	105	220	629	91	0	-
<b>5011300 Total</b>					<b>1,422</b>	<b>20</b>	<b>357</b>	<b>105</b>	<b>220</b>	<b>629</b>	<b>91</b>	<b>0</b>	<b>-</b>
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	IDU	1,286	-	-	-	-	-	1,286	-	-
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	OR	4,921	-	4,921	-	-	-	-	-	-
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	SE	3,129	44	784	231	483	1,385	201	1	-
<b>5011500 Total</b>					<b>9,336</b>	<b>44</b>	<b>5,706</b>	<b>231</b>	<b>483</b>	<b>1,385</b>	<b>1,487</b>	<b>1</b>	<b>-</b>
5012000	FUEL HAND-COAL	STEX	Steam O&M Expense	SE	6,651	94	1,667	491	1,027	2,943	427	2	-
<b>5012000 Total</b>					<b>6,651</b>	<b>94</b>	<b>1,667</b>	<b>491</b>	<b>1,027</b>	<b>2,943</b>	<b>427</b>	<b>2</b>	<b>-</b>
5013000	START UP FUEL - GAS	NPCX	Net Power Cost Expense	SE	240	3	60	18	37	106	15	0	-
<b>5013000 Total</b>					<b>240</b>	<b>3</b>	<b>60</b>	<b>18</b>	<b>37</b>	<b>106</b>	<b>15</b>	<b>0</b>	<b>-</b>
5013500	FUEL CONSUMED-GAS	NPCX	Net Power Cost Expense	SE	18,261	258	4,578	1,347	2,818	8,080	1,173	6	-
<b>5013500 Total</b>					<b>18,261</b>	<b>258</b>	<b>4,578</b>	<b>1,347</b>	<b>2,818</b>	<b>8,080</b>	<b>1,173</b>	<b>6</b>	<b>-</b>
5014000	FUEL CONSUMED-DIESEL	NPCX	Net Power Cost Expense	SE	5	0	1	0	1	2	0	0	-
<b>5014000 Total</b>					<b>5</b>	<b>0</b>	<b>1</b>	<b>0</b>	<b>1</b>	<b>2</b>	<b>0</b>	<b>0</b>	<b>-</b>
5014500	START UP FUEL-DIESEL	NPCX	Net Power Cost Expense	SE	4,021	57	1,008	297	621	1,779	258	1	-
<b>5014500 Total</b>					<b>4,021</b>	<b>57</b>	<b>1,008</b>	<b>297</b>	<b>621</b>	<b>1,779</b>	<b>258</b>	<b>1</b>	<b>-</b>
5015000	FUEL CONS-RES DISP	NPCX	Net Power Cost Expense	SE	61	1	15	4	9	27	4	0	-
<b>5015000 Total</b>					<b>61</b>	<b>1</b>	<b>15</b>	<b>4</b>	<b>9</b>	<b>27</b>	<b>4</b>	<b>0</b>	<b>-</b>
5015100	ASH & ASH BYPRD SALE	NPCX	Net Power Cost Expense	SE	2	0	1	0	0	1	0	0	-
<b>5015100 Total</b>					<b>2</b>	<b>0</b>	<b>1</b>	<b>0</b>	<b>0</b>	<b>1</b>	<b>0</b>	<b>0</b>	<b>-</b>
5020000	STEAM EXPENSES	STEX	Steam O&M Expense	SG	41,579	610	10,840	3,259	5,901	18,459	2,497	12	-
<b>5020000 Total</b>					<b>41,579</b>	<b>610</b>	<b>10,840</b>	<b>3,259</b>	<b>5,901</b>	<b>18,459</b>	<b>2,497</b>	<b>12</b>	<b>-</b>
5022000	STM EXP - FLYASH	STEX	Steam O&M Expense	SG	7,447	109	1,942	584	1,057	3,306	447	2	-
<b>5022000 Total</b>					<b>7,447</b>	<b>109</b>	<b>1,942</b>	<b>584</b>	<b>1,057</b>	<b>3,306</b>	<b>447</b>	<b>2</b>	<b>-</b>
5023000	STM EXP BOTTOM ASH	STEX	Steam O&M Expense	SG	1,000	15	261	78	142	444	60	0	-
<b>5023000 Total</b>					<b>1,000</b>	<b>15</b>	<b>261</b>	<b>78</b>	<b>142</b>	<b>444</b>	<b>60</b>	<b>0</b>	<b>-</b>
5024000	STM EXP SCRUBBER	STEX	Steam O&M Expense	SG	11,796	173	3,075	925	1,674	5,237	708	3	-
<b>5024000 Total</b>					<b>11,796</b>	<b>173</b>	<b>3,075</b>	<b>925</b>	<b>1,674</b>	<b>5,237</b>	<b>708</b>	<b>3</b>	<b>-</b>
5029000	STM EXP - OTHER	STEX	Steam O&M Expense	SG	18,300	269	4,771	1,435	2,597	8,124	1,099	5	-
<b>5029000 Total</b>					<b>18,300</b>	<b>269</b>	<b>4,771</b>	<b>1,435</b>	<b>2,597</b>	<b>8,124</b>	<b>1,099</b>	<b>5</b>	<b>-</b>
5030000	STEAM FRM OTH SRCS	NPCX	Net Power Cost Expense	SE	5,120	72	1,283	378	790	2,265	329	2	-
<b>5030000 Total</b>					<b>5,120</b>	<b>72</b>	<b>1,283</b>	<b>378</b>	<b>790</b>	<b>2,265</b>	<b>329</b>	<b>2</b>	<b>-</b>
5050000	ELECTRIC EXPENSES	STEX	Steam O&M Expense	SG	1,120	16	292	88	159	497	67	0	-
<b>5050000 Total</b>					<b>1,120</b>	<b>16</b>	<b>292</b>	<b>88</b>	<b>159</b>	<b>497</b>	<b>67</b>	<b>0</b>	<b>-</b>
5051000	ELEC EXP GENERAL	STEX	Steam O&M Expense	SG	53	1	14	4	8	24	3	0	-
<b>5051000 Total</b>					<b>53</b>	<b>1</b>	<b>14</b>	<b>4</b>	<b>8</b>	<b>24</b>	<b>3</b>	<b>0</b>	<b>-</b>
5060000	MISC STEAM PWR EXP	STEX	Steam O&M Expense	SG	78,051	1,145	20,348	6,118	11,078	34,651	4,688	23	-
<b>5060000 Total</b>					<b>78,051</b>	<b>1,145</b>	<b>20,348</b>	<b>6,118</b>	<b>11,078</b>	<b>34,651</b>	<b>4,688</b>	<b>23</b>	<b>-</b>
5061000	MISC STM EXP - CON	STEX	Steam O&M Expense	SG	1,717	25	448	135	244	762	103	1	-
<b>5061000 Total</b>					<b>1,717</b>	<b>25</b>	<b>448</b>	<b>135</b>	<b>244</b>	<b>762</b>	<b>103</b>	<b>1</b>	<b>-</b>
5061100	MISC STM EXP PLCLU	STEX	Steam O&M Expense	SG	1,826	27	476	143	259	811	110	1	-
<b>5061100 Total</b>					<b>1,826</b>	<b>27</b>	<b>476</b>	<b>143</b>	<b>259</b>	<b>811</b>	<b>110</b>	<b>1</b>	<b>-</b>
5061200	MISC STM EXP UNMTG	STEX	Steam O&M Expense	SG	7	0	2	1	1	3	0	0	-
<b>5061200 Total</b>					<b>7</b>	<b>0</b>	<b>2</b>	<b>1</b>	<b>1</b>	<b>3</b>	<b>0</b>	<b>0</b>	<b>-</b>
5061300	MISC STM EXP COMPT	STEX	Steam O&M Expense	SG	531	8	138	42	75	236	32	0	-
<b>5061300 Total</b>					<b>531</b>	<b>8</b>	<b>138</b>	<b>42</b>	<b>75</b>	<b>236</b>	<b>32</b>	<b>0</b>	<b>-</b>
5061400	MISC STM EXP OFFIC	STEX	Steam O&M Expense	SG	1,450	21	378	114	206	644	87	0	-
<b>5061400 Total</b>					<b>1,450</b>	<b>21</b>	<b>378</b>	<b>114</b>	<b>206</b>	<b>644</b>	<b>87</b>	<b>0</b>	<b>-</b>
5061500	MISC STM EXP COMM	STEX	Steam O&M Expense	SG	198	3	52	16	28	88	12	0	-
<b>5061500 Total</b>					<b>198</b>	<b>3</b>	<b>52</b>	<b>16</b>	<b>28</b>	<b>88</b>	<b>12</b>	<b>0</b>	<b>-</b>
5062000	MISC STM - ENVRMNT	STEX	Steam O&M Expense	SG	3,512	52	916	275	498	1,559	211	1	-
<b>5062000 Total</b>					<b>3,512</b>	<b>52</b>	<b>916</b>	<b>275</b>	<b>498</b>	<b>1,559</b>	<b>211</b>	<b>1</b>	<b>-</b>
5063000	MISC STEAM JVA CR	STEX	Steam O&M Expense	SG	(36,143)	(530)	(9,423)	(2,833)	(5,130)	(16,046)	(2,171)	(11)	-



Operations & Maintenance Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
<b>5063000 Total</b>					<b>(36,143)</b>	<b>(530)</b>	<b>(9,423)</b>	<b>(2,833)</b>	<b>(5,130)</b>	<b>(16,046)</b>	<b>(2,171)</b>	<b>(11)</b>	-
5064000	MISC STM EXP RCRT	STEX	Steam O&M Expense	SG	13	0	3	1	2	6	1	0	-
<b>5064000 Total</b>					<b>13</b>	<b>0</b>	<b>3</b>	<b>1</b>	<b>2</b>	<b>6</b>	<b>1</b>	<b>0</b>	-
5065000	MISC STM EXP - SEC	STEX	Steam O&M Expense	SG	422	6	110	33	60	187	25	0	-
<b>5065000 Total</b>					<b>422</b>	<b>6</b>	<b>110</b>	<b>33</b>	<b>60</b>	<b>187</b>	<b>25</b>	<b>0</b>	-
5066000	MISC STM EXP -SFTY	STEX	Steam O&M Expense	SG	836	12	218	66	119	371	50	0	-
<b>5066000 Total</b>					<b>836</b>	<b>12</b>	<b>218</b>	<b>66</b>	<b>119</b>	<b>371</b>	<b>50</b>	<b>0</b>	-
5067000	MISC STM EXP TRNNG	STEX	Steam O&M Expense	SG	3,461	51	902	271	491	1,536	208	1	-
<b>5067000 Total</b>					<b>3,461</b>	<b>51</b>	<b>902</b>	<b>271</b>	<b>491</b>	<b>1,536</b>	<b>208</b>	<b>1</b>	-
5069000	MISC STM EXP WTSPY	STEX	Steam O&M Expense	SG	473	7	123	37	67	210	28	0	-
<b>5069000 Total</b>					<b>473</b>	<b>7</b>	<b>123</b>	<b>37</b>	<b>67</b>	<b>210</b>	<b>28</b>	<b>0</b>	-
5069900	MISC STM EXP MISC	STEX	Steam O&M Expense	SG	2,473	36	645	194	351	1,098	149	1	-
<b>5069900 Total</b>					<b>2,473</b>	<b>36</b>	<b>645</b>	<b>194</b>	<b>351</b>	<b>1,098</b>	<b>149</b>	<b>1</b>	-
5070000	RENTS (STEAM GEN)	STEX	Steam O&M Expense	SG	467	7	122	37	66	207	28	0	-
<b>5070000 Total</b>					<b>467</b>	<b>7</b>	<b>122</b>	<b>37</b>	<b>66</b>	<b>207</b>	<b>28</b>	<b>0</b>	-
5100000	MNT SUPERV & ENG	STEX	Steam O&M Expense	SG	2,880	42	751	226	409	1,279	173	1	-
<b>5100000 Total</b>					<b>2,880</b>	<b>42</b>	<b>751</b>	<b>226</b>	<b>409</b>	<b>1,279</b>	<b>173</b>	<b>1</b>	-
5101000	MNTNCE SUPVSN &ENG	STEX	Steam O&M Expense	SG	4,174	61	1,088	327	592	1,853	251	1	-
<b>5101000 Total</b>					<b>4,174</b>	<b>61</b>	<b>1,088</b>	<b>327</b>	<b>592</b>	<b>1,853</b>	<b>251</b>	<b>1</b>	-
5110000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	4,320	63	1,126	339	613	1,918	259	1	-
<b>5110000 Total</b>					<b>4,320</b>	<b>63</b>	<b>1,126</b>	<b>339</b>	<b>613</b>	<b>1,918</b>	<b>259</b>	<b>1</b>	-
5111000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	4,005	59	1,044	314	568	1,778	241	1	-
<b>5111000 Total</b>					<b>4,005</b>	<b>59</b>	<b>1,044</b>	<b>314</b>	<b>568</b>	<b>1,778</b>	<b>241</b>	<b>1</b>	-
5111100	MNT STRCT PMP PLNT	STEX	Steam O&M Expense	SG	839	12	219	66	119	372	50	0	-
<b>5111100 Total</b>					<b>839</b>	<b>12</b>	<b>219</b>	<b>66</b>	<b>119</b>	<b>372</b>	<b>50</b>	<b>0</b>	-
5111200	MNT STRCT WASTE WT	STEX	Steam O&M Expense	SG	611	9	159	48	87	271	37	0	-
<b>5111200 Total</b>					<b>611</b>	<b>9</b>	<b>159</b>	<b>48</b>	<b>87</b>	<b>271</b>	<b>37</b>	<b>0</b>	-
5112000	STRUCTURAL SYSTEMS	STEX	Steam O&M Expense	SG	10,335	152	2,694	810	1,467	4,588	621	3	-
<b>5112000 Total</b>					<b>10,335</b>	<b>152</b>	<b>2,694</b>	<b>810</b>	<b>1,467</b>	<b>4,588</b>	<b>621</b>	<b>3</b>	-
5114000	MNT OF STRCT CATH	STEX	Steam O&M Expense	SG	35	1	9	3	5	16	2	0	-
<b>5114000 Total</b>					<b>35</b>	<b>1</b>	<b>9</b>	<b>3</b>	<b>5</b>	<b>16</b>	<b>2</b>	<b>0</b>	-
5116000	MNT STRCT DAM RIVR	STEX	Steam O&M Expense	SG	58	1	15	5	8	26	3	0	-
<b>5116000 Total</b>					<b>58</b>	<b>1</b>	<b>15</b>	<b>5</b>	<b>8</b>	<b>26</b>	<b>3</b>	<b>0</b>	-
5117000	MNT STRCT FIRE PRT	STEX	Steam O&M Expense	SG	1,071	16	279	84	152	476	64	0	-
<b>5117000 Total</b>					<b>1,071</b>	<b>16</b>	<b>279</b>	<b>84</b>	<b>152</b>	<b>476</b>	<b>64</b>	<b>0</b>	-
5118000	MNT STRCT-GROUNDS	STEX	Steam O&M Expense	SG	627	9	163	49	89	278	38	0	-
<b>5118000 Total</b>					<b>627</b>	<b>9</b>	<b>163</b>	<b>49</b>	<b>89</b>	<b>278</b>	<b>38</b>	<b>0</b>	-
5119000	MNT OF STRCT-HVAC	STEX	Steam O&M Expense	SG	1,921	28	501	151	273	853	115	1	-
<b>5119000 Total</b>					<b>1,921</b>	<b>28</b>	<b>501</b>	<b>151</b>	<b>273</b>	<b>853</b>	<b>115</b>	<b>1</b>	-
5119900	MNT OF STRCT-MISC	STEX	Steam O&M Expense	SG	740	11	193	58	105	328	44	0	-
<b>5119900 Total</b>					<b>740</b>	<b>11</b>	<b>193</b>	<b>58</b>	<b>105</b>	<b>328</b>	<b>44</b>	<b>0</b>	-
5120000	MANT OF BOILR PLNT	STEX	Steam O&M Expense	SG	12,615	185	3,289	989	1,790	5,600	758	4	-
<b>5120000 Total</b>					<b>12,615</b>	<b>185</b>	<b>3,289</b>	<b>989</b>	<b>1,790</b>	<b>5,600</b>	<b>758</b>	<b>4</b>	-
5121000	MNT BOILR-AIR HTR	STEX	Steam O&M Expense	SG	5,103	75	1,330	400	724	2,266	307	1	-
<b>5121000 Total</b>					<b>5,103</b>	<b>75</b>	<b>1,330</b>	<b>400</b>	<b>724</b>	<b>2,266</b>	<b>307</b>	<b>1</b>	-
5121100	MNT BOILR-CHEM FD	STEX	Steam O&M Expense	SG	166	2	43	13	24	74	10	0	-
<b>5121100 Total</b>					<b>166</b>	<b>2</b>	<b>43</b>	<b>13</b>	<b>24</b>	<b>74</b>	<b>10</b>	<b>0</b>	-
5121200	MNT BOILR-CL HANDL	STEX	Steam O&M Expense	SG	4,249	62	1,108	333	603	1,886	255	1	-
<b>5121200 Total</b>					<b>4,249</b>	<b>62</b>	<b>1,108</b>	<b>333</b>	<b>603</b>	<b>1,886</b>	<b>255</b>	<b>1</b>	-
5121400	MNT BOIL-DEMNERLZ	STEX	Steam O&M Expense	SG	413	6	108	32	59	183	25	0	-
<b>5121400 Total</b>					<b>413</b>	<b>6</b>	<b>108</b>	<b>32</b>	<b>59</b>	<b>183</b>	<b>25</b>	<b>0</b>	-
5121500	MNT BOIL-EXTRC STM	STEX	Steam O&M Expense	SG	322	5	84	25	46	143	19	0	-
<b>5121500 Total</b>					<b>322</b>	<b>5</b>	<b>84</b>	<b>25</b>	<b>46</b>	<b>143</b>	<b>19</b>	<b>0</b>	-
5121600	MNT BOILR-FLYASH	STEX	Steam O&M Expense	SG	3,656	54	953	287	519	1,623	220	1	-
<b>5121600 Total</b>					<b>3,656</b>	<b>54</b>	<b>953</b>	<b>287</b>	<b>519</b>	<b>1,623</b>	<b>220</b>	<b>1</b>	-
5121700	MNT BOIL-FUEL OIL	STEX	Steam O&M Expense	SG	618	9	161	48	88	274	37	0	-
<b>5121700 Total</b>					<b>618</b>	<b>9</b>	<b>161</b>	<b>48</b>	<b>88</b>	<b>274</b>	<b>37</b>	<b>0</b>	-
5121800	MNT BOIL-FEEDWATR	STEX	Steam O&M Expense	SG	3,610	53	941	283	512	1,603	217	1	-
<b>5121800 Total</b>					<b>3,610</b>	<b>53</b>	<b>941</b>	<b>283</b>	<b>512</b>	<b>1,603</b>	<b>217</b>	<b>1</b>	-
5121900	MNT BOIL-FRZ PRTEC	STEX	Steam O&M Expense	SG	78	1	20	6	11	34	5	0	-
<b>5121900 Total</b>					<b>78</b>	<b>1</b>	<b>20</b>	<b>6</b>	<b>11</b>	<b>34</b>	<b>5</b>	<b>0</b>	-
5122000	MNT BOILR-AUX SYST	STEX	Steam O&M Expense	SG	451	7	118	35	64	200	27	0	-
<b>5122000 Total</b>					<b>451</b>	<b>7</b>	<b>118</b>	<b>35</b>	<b>64</b>	<b>200</b>	<b>27</b>	<b>0</b>	-
5122100	MNT BOILR-MAIN STM	STEX	Steam O&M Expense	SG	2,197	32	573	172	312	975	132	1	-



Operations & Maintenance Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
<b>5122100 Total</b>					<b>2,197</b>	<b>32</b>	<b>573</b>	<b>172</b>	<b>312</b>	<b>975</b>	<b>132</b>	<b>1</b>	<b>-</b>
5122200	MNT BOIL-PLVRZD CL	STEX	Steam O&M Expense	SG	6,187	91	1,613	485	878	2,747	372	2	-
<b>5122200 Total</b>					<b>6,187</b>	<b>91</b>	<b>1,613</b>	<b>485</b>	<b>878</b>	<b>2,747</b>	<b>372</b>	<b>2</b>	<b>-</b>
5122300	MNT BOIL-PRECIP/BAG	STEX	Steam O&M Expense	SG	3,011	44	785	236	427	1,337	181	1	-
<b>5122300 Total</b>					<b>3,011</b>	<b>44</b>	<b>785</b>	<b>236</b>	<b>427</b>	<b>1,337</b>	<b>181</b>	<b>1</b>	<b>-</b>
5122400	MNT BOIL-PRTRT WTR	STEX	Steam O&M Expense	SG	287	4	75	22	41	127	17	0	-
<b>5122400 Total</b>					<b>287</b>	<b>4</b>	<b>75</b>	<b>22</b>	<b>41</b>	<b>127</b>	<b>17</b>	<b>0</b>	<b>-</b>
5122500	MNT BOIL-RV OSMIS	STEX	Steam O&M Expense	SG	154	2	40	12	22	68	9	0	-
<b>5122500 Total</b>					<b>154</b>	<b>2</b>	<b>40</b>	<b>12</b>	<b>22</b>	<b>68</b>	<b>9</b>	<b>0</b>	<b>-</b>
5122600	MNT BOIL-RHEAT ST	STEX	Steam O&M Expense	SG	465	7	121	36	66	206	28	0	-
<b>5122600 Total</b>					<b>465</b>	<b>7</b>	<b>121</b>	<b>36</b>	<b>66</b>	<b>206</b>	<b>28</b>	<b>0</b>	<b>-</b>
5122800	MNT BOIL-SOOTBLWG	STEX	Steam O&M Expense	SG	2,008	29	523	157	285	891	121	1	-
<b>5122800 Total</b>					<b>2,008</b>	<b>29</b>	<b>523</b>	<b>157</b>	<b>285</b>	<b>891</b>	<b>121</b>	<b>1</b>	<b>-</b>
5122900	MNT BOILR-SCRUBBER	STEX	Steam O&M Expense	SG	6,072	89	1,583	476	862	2,696	365	2	-
<b>5122900 Total</b>					<b>6,072</b>	<b>89</b>	<b>1,583</b>	<b>476</b>	<b>862</b>	<b>2,696</b>	<b>365</b>	<b>2</b>	<b>-</b>
5123000	MNT BOILR-BOTM ASH	STEX	Steam O&M Expense	SG	2,632	39	686	206	374	1,168	158	1	-
<b>5123000 Total</b>					<b>2,632</b>	<b>39</b>	<b>686</b>	<b>206</b>	<b>374</b>	<b>1,168</b>	<b>158</b>	<b>1</b>	<b>-</b>
5123100	MNT BOIL-WTR TRTMT	STEX	Steam O&M Expense	SG	432	6	113	34	61	192	26	0	-
<b>5123100 Total</b>					<b>432</b>	<b>6</b>	<b>113</b>	<b>34</b>	<b>61</b>	<b>192</b>	<b>26</b>	<b>0</b>	<b>-</b>
5123200	MNT BOIL-CNTL SUPT	STEX	Steam O&M Expense	SG	777	11	203	61	110	345	47	0	-
<b>5123200 Total</b>					<b>777</b>	<b>11</b>	<b>203</b>	<b>61</b>	<b>110</b>	<b>345</b>	<b>47</b>	<b>0</b>	<b>-</b>
5123300	MAINT GEO GATH SYS	STEX	Steam O&M Expense	SG	260	4	68	20	37	115	16	0	-
<b>5123300 Total</b>					<b>260</b>	<b>4</b>	<b>68</b>	<b>20</b>	<b>37</b>	<b>115</b>	<b>16</b>	<b>0</b>	<b>-</b>
5123400	MAINT OF BOILERS	STEX	Steam O&M Expense	SG	1,715	25	447	134	243	761	103	1	-
<b>5123400 Total</b>					<b>1,715</b>	<b>25</b>	<b>447</b>	<b>134</b>	<b>243</b>	<b>761</b>	<b>103</b>	<b>1</b>	<b>-</b>
5124000	MNT BOILR-CONTROLS	STEX	Steam O&M Expense	SG	1,130	17	295	89	160	502	68	0	-
<b>5124000 Total</b>					<b>1,130</b>	<b>17</b>	<b>295</b>	<b>89</b>	<b>160</b>	<b>502</b>	<b>68</b>	<b>0</b>	<b>-</b>
5125000	MNT BOILER-DRAFT	STEX	Steam O&M Expense	SG	2,644	39	689	207	375	1,174	159	1	-
<b>5125000 Total</b>					<b>2,644</b>	<b>39</b>	<b>689</b>	<b>207</b>	<b>375</b>	<b>1,174</b>	<b>159</b>	<b>1</b>	<b>-</b>
5126000	MNT BOILR-FIRESIDE	STEX	Steam O&M Expense	SG	1,430	21	373	112	203	635	86	0	-
<b>5126000 Total</b>					<b>1,430</b>	<b>21</b>	<b>373</b>	<b>112</b>	<b>203</b>	<b>635</b>	<b>86</b>	<b>0</b>	<b>-</b>
5127000	MNT BLR-BEARNG WTR	STEX	Steam O&M Expense	SG	151	2	39	12	21	67	9	0	-
<b>5127000 Total</b>					<b>151</b>	<b>2</b>	<b>39</b>	<b>12</b>	<b>21</b>	<b>67</b>	<b>9</b>	<b>0</b>	<b>-</b>
5128000	MNT BOILR WTR/STMD	STEX	Steam O&M Expense	SG	6,137	90	1,600	481	871	2,724	369	2	-
<b>5128000 Total</b>					<b>6,137</b>	<b>90</b>	<b>1,600</b>	<b>481</b>	<b>871</b>	<b>2,724</b>	<b>369</b>	<b>2</b>	<b>-</b>
5129000	MNT BOIL-COMP AIR	STEX	Steam O&M Expense	SG	326	5	85	26	46	145	20	0	-
<b>5129000 Total</b>					<b>326</b>	<b>5</b>	<b>85</b>	<b>26</b>	<b>46</b>	<b>145</b>	<b>20</b>	<b>0</b>	<b>-</b>
5129900	MAINT BOILER-MISC	STEX	Steam O&M Expense	SG	366	5	95	29	52	162	22	0	-
<b>5129900 Total</b>					<b>366</b>	<b>5</b>	<b>95</b>	<b>29</b>	<b>52</b>	<b>162</b>	<b>22</b>	<b>0</b>	<b>-</b>
5130000	MAINT ELEC PLANT	STEX	Steam O&M Expense	SG	4,008	59	1,045	314	569	1,779	241	1	-
<b>5130000 Total</b>					<b>4,008</b>	<b>59</b>	<b>1,045</b>	<b>314</b>	<b>569</b>	<b>1,779</b>	<b>241</b>	<b>1</b>	<b>-</b>
5131000	MAINT ELEC AC	STEX	Steam O&M Expense	SG	15,840	232	4,130	1,242	2,248	7,032	951	5	-
<b>5131000 Total</b>					<b>15,840</b>	<b>232</b>	<b>4,130</b>	<b>1,242</b>	<b>2,248</b>	<b>7,032</b>	<b>951</b>	<b>5</b>	<b>-</b>
5131100	MAINT/LUBE-OIL SYS	STEX	Steam O&M Expense	SG	656	10	171	51	93	291	39	0	-
<b>5131100 Total</b>					<b>656</b>	<b>10</b>	<b>171</b>	<b>51</b>	<b>93</b>	<b>291</b>	<b>39</b>	<b>0</b>	<b>-</b>
5131300	MAINT/PREVENT ROUT	STEX	Steam O&M Expense	SG	2	0	1	0	0	1	0	0	-
<b>5131300 Total</b>					<b>2</b>	<b>0</b>	<b>1</b>	<b>0</b>	<b>0</b>	<b>1</b>	<b>0</b>	<b>0</b>	<b>-</b>
5131400	MAINT/MAIN TURBINE	STEX	Steam O&M Expense	SG	4,908	72	1,280	385	697	2,179	295	1	-
<b>5131400 Total</b>					<b>4,908</b>	<b>72</b>	<b>1,280</b>	<b>385</b>	<b>697</b>	<b>2,179</b>	<b>295</b>	<b>1</b>	<b>-</b>
5132000	MAINT ALARMS/INFO	STEX	Steam O&M Expense	SG	1,476	22	385	116	209	655	89	0	-
<b>5132000 Total</b>					<b>1,476</b>	<b>22</b>	<b>385</b>	<b>116</b>	<b>209</b>	<b>655</b>	<b>89</b>	<b>0</b>	<b>-</b>
5133000	MAINT/AIR-COOL-CON	STEX	Steam O&M Expense	SG	131	2	34	10	19	58	8	0	-
<b>5133000 Total</b>					<b>131</b>	<b>2</b>	<b>34</b>	<b>10</b>	<b>19</b>	<b>58</b>	<b>8</b>	<b>0</b>	<b>-</b>
5134000	MAINT/COMPNT COOL	STEX	Steam O&M Expense	SG	149	2	39	12	21	66	9	0	-
<b>5134000 Total</b>					<b>149</b>	<b>2</b>	<b>39</b>	<b>12</b>	<b>21</b>	<b>66</b>	<b>9</b>	<b>0</b>	<b>-</b>
5135000	MAINT/COMPNT AUXIL	STEX	Steam O&M Expense	SG	1,022	15	266	80	145	454	61	0	-
<b>5135000 Total</b>					<b>1,022</b>	<b>15</b>	<b>266</b>	<b>80</b>	<b>145</b>	<b>454</b>	<b>61</b>	<b>0</b>	<b>-</b>
5137000	MAINT-COOLING TOWR	STEX	Steam O&M Expense	SG	1,835	27	479	144	261	815	110	1	-
<b>5137000 Total</b>					<b>1,835</b>	<b>27</b>	<b>479</b>	<b>144</b>	<b>261</b>	<b>815</b>	<b>110</b>	<b>1</b>	<b>-</b>
5138000	MAINT-CIRCUL WATER	STEX	Steam O&M Expense	SG	1,101	16	287	86	156	489	66	0	-
<b>5138000 Total</b>					<b>1,101</b>	<b>16</b>	<b>287</b>	<b>86</b>	<b>156</b>	<b>489</b>	<b>66</b>	<b>0</b>	<b>-</b>
5139000	MAINT-ELECT - DC	STEX	Steam O&M Expense	SG	242	4	63	19	34	107	15	0	-
<b>5139000 Total</b>					<b>242</b>	<b>4</b>	<b>63</b>	<b>19</b>	<b>34</b>	<b>107</b>	<b>15</b>	<b>0</b>	<b>-</b>
5139900	MNT ELEC PLT-MISC	STEX	Steam O&M Expense	SG	25	0	6	2	4	11	1	0	-



Operations & Maintenance Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
<b>5139000 Total</b>					<b>25</b>	<b>0</b>	<b>6</b>	<b>2</b>	<b>4</b>	<b>11</b>	<b>1</b>	<b>0</b>	<b>-</b>
5140000	MAINT MISC STM PLN	STEX	Steam O&M Expense	SG	4,710	69	1,228	369	668	2,091	283	1	-
<b>5140000 Total</b>					<b>4,710</b>	<b>69</b>	<b>1,228</b>	<b>369</b>	<b>668</b>	<b>2,091</b>	<b>283</b>	<b>1</b>	<b>-</b>
5141000	MISC STM-COMP AIR	STEX	Steam O&M Expense	SG	1,526	22	398	120	217	677	92	0	-
<b>5141000 Total</b>					<b>1,526</b>	<b>22</b>	<b>398</b>	<b>120</b>	<b>217</b>	<b>677</b>	<b>92</b>	<b>0</b>	<b>-</b>
5142000	MISC STM PLT-CONSU	STEX	Steam O&M Expense	SG	168	2	44	13	24	75	10	0	-
<b>5142000 Total</b>					<b>168</b>	<b>2</b>	<b>44</b>	<b>13</b>	<b>24</b>	<b>75</b>	<b>10</b>	<b>0</b>	<b>-</b>
5144000	MISC STM PLNT-LAB	STEX	Steam O&M Expense	SG	214	3	56	17	30	95	13	0	-
<b>5144000 Total</b>					<b>214</b>	<b>3</b>	<b>56</b>	<b>17</b>	<b>30</b>	<b>95</b>	<b>13</b>	<b>0</b>	<b>-</b>
5145000	MAINT MISC-SM TOOL	STEX	Steam O&M Expense	SG	449	7	117	35	64	199	27	0	-
<b>5145000 Total</b>					<b>449</b>	<b>7</b>	<b>117</b>	<b>35</b>	<b>64</b>	<b>199</b>	<b>27</b>	<b>0</b>	<b>-</b>
5146000	MAINT/PAGING SYS	STEX	Steam O&M Expense	SG	237	3	62	19	34	105	14	0	-
<b>5146000 Total</b>					<b>237</b>	<b>3</b>	<b>62</b>	<b>19</b>	<b>34</b>	<b>105</b>	<b>14</b>	<b>0</b>	<b>-</b>
5147000	MAINT/PLANT EQUIP	STEX	Steam O&M Expense	SG	1,206	18	314	95	171	535	72	0	-
<b>5147000 Total</b>					<b>1,206</b>	<b>18</b>	<b>314</b>	<b>95</b>	<b>171</b>	<b>535</b>	<b>72</b>	<b>0</b>	<b>-</b>
5148000	MAINT/PLT-VEHICLES	STEX	Steam O&M Expense	SG	1,987	29	518	156	282	882	119	1	-
<b>5148000 Total</b>					<b>1,987</b>	<b>29</b>	<b>518</b>	<b>156</b>	<b>282</b>	<b>882</b>	<b>119</b>	<b>1</b>	<b>-</b>
5149000	MAINT MISC-OTHER	STEX	Steam O&M Expense	SG	108	2	28	8	15	48	6	0	-
<b>5149000 Total</b>					<b>108</b>	<b>2</b>	<b>28</b>	<b>8</b>	<b>15</b>	<b>48</b>	<b>6</b>	<b>0</b>	<b>-</b>
5149500	MAINT STM PLT-ENV AM	STEX	Steam O&M Expense	SG	1,439	21	375	113	204	639	86	0	-
<b>5149500 Total</b>					<b>1,439</b>	<b>21</b>	<b>375</b>	<b>113</b>	<b>204</b>	<b>639</b>	<b>86</b>	<b>0</b>	<b>-</b>
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	9,462	139	2,467	742	1,343	4,200	568	3	-
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-U	1,638	24	427	128	232	727	98	0	-
<b>5350000 Total</b>					<b>11,099</b>	<b>163</b>	<b>2,894</b>	<b>870</b>	<b>1,575</b>	<b>4,928</b>	<b>667</b>	<b>3</b>	<b>-</b>
5360000	WATER FOR POWER	HYEX	Hydro O&M Expense	SG-P	294	4	77	23	42	131	18	0	-
<b>5360000 Total</b>					<b>294</b>	<b>4</b>	<b>77</b>	<b>23</b>	<b>42</b>	<b>131</b>	<b>18</b>	<b>0</b>	<b>-</b>
5370000	HYDRAULIC EXPENSES	HYEX	Hydro O&M Expense	SG-P	2,734	40	713	214	388	1,214	164	1	-
<b>5370000 Total</b>					<b>2,734</b>	<b>40</b>	<b>713</b>	<b>214</b>	<b>388</b>	<b>1,214</b>	<b>164</b>	<b>1</b>	<b>-</b>
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-P	539	8	141	42	77	239	32	0	-
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-U	114	2	30	9	16	51	7	0	-
<b>5371000 Total</b>					<b>653</b>	<b>10</b>	<b>170</b>	<b>51</b>	<b>93</b>	<b>290</b>	<b>39</b>	<b>0</b>	<b>-</b>
5372000	HYDRO/HATCHERY EXP	HYEX	Hydro O&M Expense	SG-P	193	3	50	15	27	86	12	0	-
<b>5372000 Total</b>					<b>193</b>	<b>3</b>	<b>50</b>	<b>15</b>	<b>27</b>	<b>86</b>	<b>12</b>	<b>0</b>	<b>-</b>
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	201	3	52	16	29	89	12	0	-
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-U	23	0	6	2	3	10	1	0	-
<b>5374000 Total</b>					<b>224</b>	<b>3</b>	<b>59</b>	<b>18</b>	<b>32</b>	<b>100</b>	<b>13</b>	<b>0</b>	<b>-</b>
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-P	490	7	128	38	70	218	29	0	-
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-U	180	3	47	14	26	80	11	0	-
<b>5379000 Total</b>					<b>671</b>	<b>10</b>	<b>175</b>	<b>53</b>	<b>95</b>	<b>298</b>	<b>40</b>	<b>0</b>	<b>-</b>
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-P	11,779	173	3,071	923	1,672	5,229	707	3	-
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-U	6,544	96	1,706	513	929	2,905	393	2	-
<b>5390000 Total</b>					<b>18,323</b>	<b>269</b>	<b>4,777</b>	<b>1,436</b>	<b>2,601</b>	<b>8,134</b>	<b>1,100</b>	<b>5</b>	<b>-</b>
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-P	1,430	21	373	112	203	635	86	0	-
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-U	64	1	17	5	9	28	4	0	-
<b>5400000 Total</b>					<b>1,494</b>	<b>22</b>	<b>389</b>	<b>117</b>	<b>212</b>	<b>663</b>	<b>90</b>	<b>0</b>	<b>-</b>
5410000	MNT SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	0	0	0	0	0	0	0	0	-
<b>5410000 Total</b>					<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>-</b>
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-P	742	11	194	58	105	330	45	0	-
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-U	73	1	19	6	10	32	4	0	-
<b>5420000 Total</b>					<b>815</b>	<b>12</b>	<b>213</b>	<b>64</b>	<b>116</b>	<b>362</b>	<b>49</b>	<b>0</b>	<b>-</b>
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-P	694	10	181	54	98	308	42	0	-
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-U	355	5	93	28	50	158	21	0	-
<b>5430000 Total</b>					<b>1,049</b>	<b>15</b>	<b>273</b>	<b>82</b>	<b>149</b>	<b>466</b>	<b>63</b>	<b>0</b>	<b>-</b>
5440000	MAINT OF ELEC PLNT	HYEX	Hydro O&M Expense	SG-U	85	1	22	7	12	38	5	0	-
<b>5440000 Total</b>					<b>85</b>	<b>1</b>	<b>22</b>	<b>7</b>	<b>12</b>	<b>38</b>	<b>5</b>	<b>0</b>	<b>-</b>
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-P	1,031	15	269	81	146	458	62	0	-
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-U	98	1	25	8	14	43	6	0	-
<b>5441000 Total</b>					<b>1,129</b>	<b>17</b>	<b>294</b>	<b>88</b>	<b>160</b>	<b>501</b>	<b>68</b>	<b>0</b>	<b>-</b>
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-P	597	9	156	47	85	265	36	0	-
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-U	68	1	18	5	10	30	4	0	-
<b>5442000 Total</b>					<b>665</b>	<b>10</b>	<b>173</b>	<b>52</b>	<b>94</b>	<b>295</b>	<b>40</b>	<b>0</b>	<b>-</b>
5450000	MNT MISC HYDRO PLT	HYEX	Hydro O&M Expense	SG-P	18	0	5	1	2	8	1	0	-
<b>5450000 Total</b>					<b>18</b>	<b>0</b>	<b>5</b>	<b>1</b>	<b>2</b>	<b>8</b>	<b>1</b>	<b>0</b>	<b>-</b>
5451000	MNT-FISH/WILDLIFE	HYEX	Hydro O&M Expense	SG-P	568	8	148	45	81	252	34	0	-
<b>5451000 Total</b>					<b>568</b>	<b>8</b>	<b>148</b>	<b>45</b>	<b>81</b>	<b>252</b>	<b>34</b>	<b>0</b>	<b>-</b>



Operations & Maintenance Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5454000	MAINT-OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	0	0	0	0	0	0	0	0	-
<b>5454000 Total</b>					<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>-</b>
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-P	919	13	240	72	130	408	55	0	-
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-U	441	6	115	35	63	196	26	0	-
<b>5455000 Total</b>					<b>1,360</b>	<b>20</b>	<b>355</b>	<b>107</b>	<b>193</b>	<b>604</b>	<b>82</b>	<b>0</b>	<b>-</b>
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG	33,000	484	8,603	2,587	4,684	14,650	1,982	10	-
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-P	1,417	21	369	111	201	629	85	0	-
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-U	396	6	103	31	56	176	24	0	-
<b>5459000 Total</b>					<b>34,812</b>	<b>511</b>	<b>9,076</b>	<b>2,729</b>	<b>4,941</b>	<b>15,455</b>	<b>2,091</b>	<b>10</b>	<b>-</b>
5459500	MAINT OF HYDRO PLT-E	HYEX	Hydro O&M Expense	SG-P	84	1	22	7	12	37	5	0	-
<b>5459500 Total</b>					<b>84</b>	<b>1</b>	<b>22</b>	<b>7</b>	<b>12</b>	<b>37</b>	<b>5</b>	<b>0</b>	<b>-</b>
5460000	OPER SUPERV & ENG	OPEX	Other Production O&M Expense	SG	320	5	84	25	45	142	19	0	-
<b>5460000 Total</b>					<b>320</b>	<b>5</b>	<b>84</b>	<b>25</b>	<b>45</b>	<b>142</b>	<b>19</b>	<b>0</b>	<b>-</b>
5471000	NATURAL GAS	NPCX	Net Power Cost Expense	SE	291,053	4,113	72,961	21,474	44,922	128,785	18,697	99	-
<b>5471000 Total</b>					<b>291,053</b>	<b>4,113</b>	<b>72,961</b>	<b>21,474</b>	<b>44,922</b>	<b>128,785</b>	<b>18,697</b>	<b>99</b>	<b>-</b>
5480000	GENERATION EXP	OPEX	Other Production O&M Expense	SG	18,033	265	4,701	1,414	2,559	8,006	1,083	5	-
<b>5480000 Total</b>					<b>18,033</b>	<b>265</b>	<b>4,701</b>	<b>1,414</b>	<b>2,559</b>	<b>8,006</b>	<b>1,083</b>	<b>5</b>	<b>-</b>
5490000	MIS OTH PWR GEN EX	OPEX	Other Production O&M Expense	OR	32	-	32	-	-	-	-	-	-
5490000	MIS OTH PWR GEN EX	OPEX	Other Production O&M Expense	SG	8,525	125	2,223	668	1,210	3,785	512	2	-
<b>5490000 Total</b>					<b>8,557</b>	<b>125</b>	<b>2,255</b>	<b>668</b>	<b>1,210</b>	<b>3,785</b>	<b>512</b>	<b>2</b>	<b>-</b>
5500000	RENTS (OTHER GEN)	OPEX	Other Production O&M Expense	OR	378	-	378	-	-	-	-	-	-
5500000	RENTS (OTHER GEN)	OPEX	Other Production O&M Expense	SG	7,464	110	1,946	585	1,059	3,314	448	2	-
<b>5500000 Total</b>					<b>7,842</b>	<b>110</b>	<b>2,324</b>	<b>585</b>	<b>1,059</b>	<b>3,314</b>	<b>448</b>	<b>2</b>	<b>-</b>
5520000	MAINT OF STRUCTURE	OPEX	Other Production O&M Expense	SG	2,353	35	614	184	334	1,045	141	1	-
<b>5520000 Total</b>					<b>2,353</b>	<b>35</b>	<b>614</b>	<b>184</b>	<b>334</b>	<b>1,045</b>	<b>141</b>	<b>1</b>	<b>-</b>
5530000	MNT GEN & ELEC PLT	OPEX	Other Production O&M Expense	SG	15,161	222	3,953	1,188	2,152	6,731	911	4	-
<b>5530000 Total</b>					<b>15,161</b>	<b>222</b>	<b>3,953</b>	<b>1,188</b>	<b>2,152</b>	<b>6,731</b>	<b>911</b>	<b>4</b>	<b>-</b>
5540000	MNT MSC OTH PWR GN	OPEX	Other Production O&M Expense	SG	1,128	17	294	88	160	501	68	0	-
<b>5540000 Total</b>					<b>1,128</b>	<b>17</b>	<b>294</b>	<b>88</b>	<b>160</b>	<b>501</b>	<b>68</b>	<b>0</b>	<b>-</b>
5546000	MISC PLANT EQUIP	OPEX	Other Production O&M Expense	SG	33	0	9	3	5	15	2	0	-
<b>5546000 Total</b>					<b>33</b>	<b>0</b>	<b>9</b>	<b>3</b>	<b>5</b>	<b>15</b>	<b>2</b>	<b>0</b>	<b>-</b>
5549500	MAINT OF OTH PWR PLT	OPEX	Other Production O&M Expense	SG	1,971	29	514	154	280	875	118	1	-
5549500	MAINT OF OTH PWR PLT	OPEX	Other Production O&M Expense	SG	0	0	0	0	0	0	0	0	-
<b>5549500 Total</b>					<b>1,971</b>	<b>29</b>	<b>514</b>	<b>154</b>	<b>280</b>	<b>875</b>	<b>118</b>	<b>1</b>	<b>-</b>
5550000	PURCHASED POWER	PSEX	Power Supply Expense	SG	674	10	176	53	96	299	41	0	-
<b>5550000 Total</b>					<b>674</b>	<b>10</b>	<b>176</b>	<b>53</b>	<b>96</b>	<b>299</b>	<b>41</b>	<b>0</b>	<b>-</b>
5552400	RENEW ENRGY CR PURCH	NPCX	Net Power Cost Expense	OTHER	4,162	-	-	-	-	-	-	-	4,162
<b>5552400 Total</b>					<b>4,162</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>4,162</b>
5552500	OTH/INT/REC/DEL	NPCX	Net Power Cost Expense	SE	62,782	887	15,738	4,632	9,690	27,780	4,033	21	-
<b>5552500 Total</b>					<b>62,782</b>	<b>887</b>	<b>15,738</b>	<b>4,632</b>	<b>9,690</b>	<b>27,780</b>	<b>4,033</b>	<b>21</b>	<b>-</b>
5552700	PURCH POWER-UT SITUS	NPCX	Net Power Cost Expense	UT	10,278	-	-	-	-	10,278	-	-	-
<b>5552700 Total</b>					<b>10,278</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>10,278</b>	<b>-</b>	<b>-</b>	<b>-</b>
5555700	NPC Deferral Mchsm	NPCX	Net Power Cost Expense	OTHER	(171)	-	-	-	-	-	-	-	(171)
<b>5555700 Total</b>					<b>(171)</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>(171)</b>
5555900	Short-Term Firm Whls	NPCX	Net Power Cost Expense	SG	250,160	3,671	65,218	19,610	35,506	111,058	15,024	73	-
<b>5555900 Total</b>					<b>250,160</b>	<b>3,671</b>	<b>65,218</b>	<b>19,610</b>	<b>35,506</b>	<b>111,058</b>	<b>15,024</b>	<b>73</b>	<b>-</b>
5556200	TRADING NETTED-LOSS	NPCX	Net Power Cost Expense	SG	9	0	2	1	1	4	1	0	-
<b>5556200 Total</b>					<b>9</b>	<b>0</b>	<b>2</b>	<b>1</b>	<b>1</b>	<b>4</b>	<b>1</b>	<b>0</b>	<b>-</b>
5556300	FIRM ENERGY PURCH	NPCX	Net Power Cost Expense	SG	449,429	6,594	117,168	35,230	63,789	199,524	26,992	132	-
<b>5556300 Total</b>					<b>449,429</b>	<b>6,594</b>	<b>117,168</b>	<b>35,230</b>	<b>63,789</b>	<b>199,524</b>	<b>26,992</b>	<b>132</b>	<b>-</b>
5556400	FIRM DEMAND PURCH	NPCX	Net Power Cost Expense	SG	35,434	520	9,238	2,778	5,029	15,731	2,128	10	-
<b>5556400 Total</b>					<b>35,434</b>	<b>520</b>	<b>9,238</b>	<b>2,778</b>	<b>5,029</b>	<b>15,731</b>	<b>2,128</b>	<b>10</b>	<b>-</b>
5556700	POST-MERG FIRM PUR	NPCX	Net Power Cost Expense	SG	(51,310)	(753)	(13,377)	(4,022)	(7,283)	(22,779)	(3,082)	(15)	-
<b>5556700 Total</b>					<b>(51,310)</b>	<b>(753)</b>	<b>(13,377)</b>	<b>(4,022)</b>	<b>(7,283)</b>	<b>(22,779)</b>	<b>(3,082)</b>	<b>(15)</b>	<b>-</b>
5556710	EIM - FIRM PURCHASES	NPCX	Net Power Cost Expense	SG	(64,885)	(952)	(16,916)	(5,086)	(9,209)	(28,806)	(3,897)	(19)	-
<b>5556710 Total</b>					<b>(64,885)</b>	<b>(952)</b>	<b>(16,916)</b>	<b>(5,086)</b>	<b>(9,209)</b>	<b>(28,806)</b>	<b>(3,897)</b>	<b>(19)</b>	<b>-</b>
5558000	PUR PWR-UNDR CAP LEA	NPCX	Net Power Cost Expense	SG	1,507	22	393	118	214	669	91	0	-
<b>5558000 Total</b>					<b>1,507</b>	<b>22</b>	<b>393</b>	<b>118</b>	<b>214</b>	<b>669</b>	<b>91</b>	<b>0</b>	<b>-</b>
5560000	SYS CTRL & LD DISP	PSEX	Power Supply Expense	SG	596	9	155	47	85	265	36	0	-
<b>5560000 Total</b>					<b>596</b>	<b>9</b>	<b>155</b>	<b>47</b>	<b>85</b>	<b>265</b>	<b>36</b>	<b>0</b>	<b>-</b>
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SE	9	0	2	1	1	4	1	0	-
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SG	34,993	513	9,123	2,743	4,967	15,535	2,102	10	-
<b>5570000 Total</b>					<b>35,001</b>	<b>514</b>	<b>9,125</b>	<b>2,744</b>	<b>4,968</b>	<b>15,539</b>	<b>2,102</b>	<b>10</b>	<b>-</b>
5579000	OTH EXP-ST SITUS ACT	PSEX	Power Supply Expense	IDU	3,739	-	-	-	-	-	3,739	-	-
5579000	OTH EXP-ST SITUS ACT	PSEX	Power Supply Expense	OR	3,051	-	3,051	-	-	-	-	-	-



Operations & Maintenance Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
<b>5579000 Total</b>					<b>6,789</b>	-	<b>3,051</b>	-	-	-	<b>3,739</b>	-	-
5579100	OTH EXP-LIQ DAMAGE	PSEX	Power Supply Expense	UT	35	-	-	-	-	35	-	-	-
5579100	OTH EXP-LIQ DAMAGE	PSEX	Power Supply Expense	WYU	54	-	-	-	54	-	-	-	-
<b>5579100 Total</b>					<b>89</b>	-	-	-	<b>54</b>	<b>35</b>	-	-	-
5600000	OPER SUPERV & ENG	TNEX	Transmission O&M Expense	SG	8,985	132	2,342	704	1,275	3,989	540	3	-
<b>5600000 Total</b>					<b>8,985</b>	<b>132</b>	<b>2,342</b>	<b>704</b>	<b>1,275</b>	<b>3,989</b>	<b>540</b>	<b>3</b>	-
5612000	LD - MONITOR & OPER	TNEX	Transmission O&M Expense	SG	7,132	105	1,859	559	1,012	3,166	428	2	-
<b>5612000 Total</b>					<b>7,132</b>	<b>105</b>	<b>1,859</b>	<b>559</b>	<b>1,012</b>	<b>3,166</b>	<b>428</b>	<b>2</b>	-
5614000	SCHEG, SYS CTR & DSP	TNEX	Transmission O&M Expense	SG	327	5	85	26	46	145	20	0	-
<b>5614000 Total</b>					<b>327</b>	<b>5</b>	<b>85</b>	<b>26</b>	<b>46</b>	<b>145</b>	<b>20</b>	<b>0</b>	-
5614010	EIM - SCHEDULING,SYS	TNEX	Transmission O&M Expense	SG	754	11	196	59	107	335	45	0	-
<b>5614010 Total</b>					<b>754</b>	<b>11</b>	<b>196</b>	<b>59</b>	<b>107</b>	<b>335</b>	<b>45</b>	<b>0</b>	-
5615000	REL PLAN & STDS DEV	TNEX	Transmission O&M Expense	SG	2,396	35	625	188	340	1,064	144	1	-
<b>5615000 Total</b>					<b>2,396</b>	<b>35</b>	<b>625</b>	<b>188</b>	<b>340</b>	<b>1,064</b>	<b>144</b>	<b>1</b>	-
5616000	TRANS SVC STUDIES	TNEX	Transmission O&M Expense	SG	132	2	34	10	19	59	8	0	-
<b>5616000 Total</b>					<b>132</b>	<b>2</b>	<b>34</b>	<b>10</b>	<b>19</b>	<b>59</b>	<b>8</b>	<b>0</b>	-
5617000	GEN INTERCNCCT STUD	TNEX	Transmission O&M Expense	SG	1,250	18	326	98	177	555	75	0	-
<b>5617000 Total</b>					<b>1,250</b>	<b>18</b>	<b>326</b>	<b>98</b>	<b>177</b>	<b>555</b>	<b>75</b>	<b>0</b>	-
5618000	REL PLN & STAND SVCS	TNEX	Transmission O&M Expense	SG	5,785	85	1,508	453	821	2,568	347	2	-
<b>5618000 Total</b>					<b>5,785</b>	<b>85</b>	<b>1,508</b>	<b>453</b>	<b>821</b>	<b>2,568</b>	<b>347</b>	<b>2</b>	-
5620000	STATION EXP(TRANS)	TNEX	Transmission O&M Expense	SG	3,230	47	842	253	458	1,434	194	1	-
<b>5620000 Total</b>					<b>3,230</b>	<b>47</b>	<b>842</b>	<b>253</b>	<b>458</b>	<b>1,434</b>	<b>194</b>	<b>1</b>	-
5630000	OVERHEAD LINE EXP	TNEX	Transmission O&M Expense	SG	961	14	251	75	136	427	58	0	-
<b>5630000 Total</b>					<b>961</b>	<b>14</b>	<b>251</b>	<b>75</b>	<b>136</b>	<b>427</b>	<b>58</b>	<b>0</b>	-
5650000	TRNS ELEC BY OTHRS	NPCX	Net Power Cost Expense	SG	(24)	(0)	(6)	(2)	(3)	(11)	(1)	(0)	-
<b>5650000 Total</b>					<b>(24)</b>	<b>(0)</b>	<b>(6)</b>	<b>(2)</b>	<b>(3)</b>	<b>(11)</b>	<b>(1)</b>	<b>(0)</b>	-
5650010	EIM - TRANSM OF ELEC	NPCX	Net Power Cost Expense	SG	2,287	34	596	179	325	1,015	137	1	-
<b>5650010 Total</b>					<b>2,287</b>	<b>34</b>	<b>596</b>	<b>179</b>	<b>325</b>	<b>1,015</b>	<b>137</b>	<b>1</b>	-
5651000	S/T FIRM WHEELING	NPCX	Net Power Cost Expense	SG	6,362	93	1,659	499	903	2,824	382	2	-
<b>5651000 Total</b>					<b>6,362</b>	<b>93</b>	<b>1,659</b>	<b>499</b>	<b>903</b>	<b>2,824</b>	<b>382</b>	<b>2</b>	-
5652500	NON-FIRM WHEEL EXP	NPCX	Net Power Cost Expense	SE	15,972	226	4,004	1,178	2,465	7,067	1,026	5	-
<b>5652500 Total</b>					<b>15,972</b>	<b>226</b>	<b>4,004</b>	<b>1,178</b>	<b>2,465</b>	<b>7,067</b>	<b>1,026</b>	<b>5</b>	-
5654600	POST-MRG WHEEL EXP	NPCX	Net Power Cost Expense	SG	124,770	1,831	32,528	9,781	17,709	55,392	7,494	37	-
<b>5654600 Total</b>					<b>124,770</b>	<b>1,831</b>	<b>32,528</b>	<b>9,781</b>	<b>17,709</b>	<b>55,392</b>	<b>7,494</b>	<b>37</b>	-
5660000	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	3,609	53	941	283	512	1,602	217	1	-
<b>5660000 Total</b>					<b>3,609</b>	<b>53</b>	<b>941</b>	<b>283</b>	<b>512</b>	<b>1,602</b>	<b>217</b>	<b>1</b>	-
5660010	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
<b>5660010 Total</b>					<b>(0)</b>	<b>(0)</b>	<b>(0)</b>	<b>(0)</b>	<b>(0)</b>	<b>(0)</b>	<b>(0)</b>	<b>(0)</b>	-
5670000	RENTS-TRANSMISSION	TNEX	Transmission O&M Expense	SG	2,482	36	647	195	352	1,102	149	1	-
<b>5670000 Total</b>					<b>2,482</b>	<b>36</b>	<b>647</b>	<b>195</b>	<b>352</b>	<b>1,102</b>	<b>149</b>	<b>1</b>	-
5680000	MNT SUPERV & ENG	TNEX	Transmission O&M Expense	SG	845	12	220	66	120	375	51	0	-
<b>5680000 Total</b>					<b>845</b>	<b>12</b>	<b>220</b>	<b>66</b>	<b>120</b>	<b>375</b>	<b>51</b>	<b>0</b>	-
5690000	MAINT OF STRUCTURE	TNEX	Transmission O&M Expense	SG	95	1	25	7	14	42	6	0	-
<b>5690000 Total</b>					<b>95</b>	<b>1</b>	<b>25</b>	<b>7</b>	<b>14</b>	<b>42</b>	<b>6</b>	<b>0</b>	-
5692000	MAINT-COMP SW TRANS	TNEX	Transmission O&M Expense	SG	700	10	183	55	99	311	42	0	-
<b>5692000 Total</b>					<b>700</b>	<b>10</b>	<b>183</b>	<b>55</b>	<b>99</b>	<b>311</b>	<b>42</b>	<b>0</b>	-
5693000	MAINT-COM EQP TRANS	TNEX	Transmission O&M Expense	SG	4,445	65	1,159	348	631	1,973	267	1	-
<b>5693000 Total</b>					<b>4,445</b>	<b>65</b>	<b>1,159</b>	<b>348</b>	<b>631</b>	<b>1,973</b>	<b>267</b>	<b>1</b>	-
5700000	MAINT STATION EQIP	TNEX	Transmission O&M Expense	SG	10,323	151	2,691	809	1,465	4,583	620	3	-
<b>5700000 Total</b>					<b>10,323</b>	<b>151</b>	<b>2,691</b>	<b>809</b>	<b>1,465</b>	<b>4,583</b>	<b>620</b>	<b>3</b>	-
5710000	MAINT OVHD LINES	TNEX	Transmission O&M Expense	SG	17,663	259	4,605	1,385	2,507	7,841	1,061	5	-
<b>5710000 Total</b>					<b>17,663</b>	<b>259</b>	<b>4,605</b>	<b>1,385</b>	<b>2,507</b>	<b>7,841</b>	<b>1,061</b>	<b>5</b>	-
5720000	MNT UNDERGRD LINES	TNEX	Transmission O&M Expense	SG	170	2	44	13	24	75	10	0	-
<b>5720000 Total</b>					<b>170</b>	<b>2</b>	<b>44</b>	<b>13</b>	<b>24</b>	<b>75</b>	<b>10</b>	<b>0</b>	-
5730000	MNT MSC TRANS PLNT	TNEX	Transmission O&M Expense	SG	177	3	46	14	25	79	11	0	-
<b>5730000 Total</b>					<b>177</b>	<b>3</b>	<b>46</b>	<b>14</b>	<b>25</b>	<b>79</b>	<b>11</b>	<b>0</b>	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	CA	657	657	-	-	-	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	120	-	-	-	-	-	120	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	OR	431	-	431	-	-	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	8,122	288	2,150	519	780	3,954	431	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	UT	85	-	-	-	-	85	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WA	322	-	-	322	-	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	81	-	-	-	81	-	-	-	-
<b>5800000 Total</b>					<b>9,816</b>	<b>944</b>	<b>2,581</b>	<b>841</b>	<b>861</b>	<b>4,038</b>	<b>551</b>	-	-
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	SNPD	12,715	450	3,366	813	1,221	6,190	676	-	-



Operations & Maintenance Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
<b>5810000 Total</b>					<b>12,715</b>	<b>450</b>	<b>3,366</b>	<b>813</b>	<b>1,221</b>	<b>6,190</b>	<b>676</b>	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	CA	104	104	-	-	-	-	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	IDU	214	-	-	-	-	-	214	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	OR	1,104	-	1,104	-	-	-	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	SNPD	17	1	5	1	2	8	1	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	UT	1,818	-	-	-	-	1,818	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WA	293	-	-	293	-	-	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYP	702	-	-	-	702	-	-	-	-
<b>5820000 Total</b>					<b>4,252</b>	<b>105</b>	<b>1,109</b>	<b>294</b>	<b>704</b>	<b>1,826</b>	<b>215</b>	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	CA	381	381	-	-	-	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	IDU	278	-	-	-	-	-	278	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	OR	1,780	-	1,780	-	-	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	SNPD	0	0	0	0	0	0	0	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	UT	6,147	-	-	-	-	6,147	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WA	324	-	-	324	-	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYP	376	-	-	-	376	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYU	74	-	-	-	74	-	-	-	-
<b>5830000 Total</b>					<b>9,361</b>	<b>381</b>	<b>1,780</b>	<b>324</b>	<b>450</b>	<b>6,148</b>	<b>278</b>	-	-
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	OR	0	-	0	-	-	-	-	-	-
<b>5840000 Total</b>					<b>0</b>	<b>-</b>	<b>0</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
5850000	STRT LGHT-SGNL SYS	DNEX	Distribution O&M Expense	SNPD	324	11	86	21	31	158	17	-	-
<b>5850000 Total</b>					<b>324</b>	<b>11</b>	<b>86</b>	<b>21</b>	<b>31</b>	<b>158</b>	<b>17</b>	<b>-</b>	<b>-</b>
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	CA	101	101	-	-	-	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	IDU	172	-	-	-	-	-	172	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	OR	1,273	-	1,273	-	-	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	UT	502	-	-	-	-	502	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WA	371	-	-	371	-	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYP	251	-	-	-	251	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYU	81	-	-	-	81	-	-	-	-
<b>5860000 Total</b>					<b>2,751</b>	<b>101</b>	<b>1,273</b>	<b>371</b>	<b>332</b>	<b>502</b>	<b>172</b>	<b>-</b>	<b>-</b>
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	CA	557	557	-	-	-	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	IDU	838	-	-	-	-	-	838	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	OR	6,350	-	6,350	-	-	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	UT	6,075	-	-	-	-	6,075	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WA	1,362	-	-	1,362	-	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYP	1,257	-	-	-	1,257	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYU	115	-	-	-	115	-	-	-	-
<b>5870000 Total</b>					<b>16,554</b>	<b>557</b>	<b>6,350</b>	<b>1,362</b>	<b>1,372</b>	<b>6,075</b>	<b>838</b>	<b>-</b>	<b>-</b>
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	CA	(90)	(90)	-	-	-	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	IDU	3	-	-	-	-	-	3	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	OR	(115)	-	(115)	-	-	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	SNPD	663	23	175	42	64	323	35	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	UT	693	-	-	-	-	693	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WA	(2)	-	-	(2)	-	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYP	18	-	-	-	18	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYU	(91)	-	-	-	(91)	-	-	-	-
<b>5880000 Total</b>					<b>1,078</b>	<b>(66)</b>	<b>60</b>	<b>40</b>	<b>(10)</b>	<b>1,015</b>	<b>38</b>	<b>-</b>	<b>-</b>
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	CA	86	86	-	-	-	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	IDU	49	-	-	-	-	-	49	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	OR	1,872	-	1,872	-	-	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	SNPD	25	1	7	2	2	12	1	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	UT	754	-	-	-	-	754	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WA	204	-	-	204	-	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYP	435	-	-	-	435	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYU	127	-	-	-	127	-	-	-	-
<b>5890000 Total</b>					<b>3,552</b>	<b>87</b>	<b>1,879</b>	<b>205</b>	<b>564</b>	<b>766</b>	<b>51</b>	<b>-</b>	<b>-</b>
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	CA	121	121	-	-	-	-	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	247	-	-	-	-	-	247	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	OR	822	-	822	-	-	-	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	2,561	91	678	164	246	1,247	136	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	UT	1,029	-	-	-	-	1,029	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WA	187	-	-	187	-	-	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	392	-	-	-	392	-	-	-	-
<b>5900000 Total</b>					<b>5,359</b>	<b>212</b>	<b>1,500</b>	<b>351</b>	<b>637</b>	<b>2,275</b>	<b>383</b>	<b>-</b>	<b>-</b>
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	CA	178	178	-	-	-	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	IDU	127	-	-	-	-	-	127	-	-





Operations & Maintenance Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	OR	500	-	500	-	-	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	SNPD	60	2	16	4	6	29	3	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	UT	608	-	-	-	-	608	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WA	127	-	-	127	-	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYP	158	-	-	-	158	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYU	58	-	-	-	58	-	-	-	-
<b>5910000 Total</b>					<b>1,816</b>	<b>181</b>	<b>516</b>	<b>131</b>	<b>221</b>	<b>637</b>	<b>130</b>	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	CA	329	329	-	-	-	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	IDU	405	-	-	-	-	-	405	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	OR	2,723	-	2,723	-	-	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	SNPD	1,565	55	414	100	150	762	83	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	UT	2,154	-	-	-	-	2,154	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WA	635	-	-	635	-	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYP	927	-	-	-	927	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYU	27	-	-	-	27	-	-	-	-
<b>5920000 Total</b>					<b>8,765</b>	<b>384</b>	<b>3,137</b>	<b>735</b>	<b>1,104</b>	<b>2,916</b>	<b>488</b>	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	CA	8,760	8,760	-	-	-	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	IDU	3,561	-	-	-	-	-	3,561	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	OR	54,803	-	54,803	-	-	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	SNPD	2,450	87	649	157	235	1,193	130	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	UT	30,083	-	-	-	-	30,083	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WA	5,970	-	-	5,970	-	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYP	5,049	-	-	-	5,049	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYU	758	-	-	-	758	-	-	-	-
<b>5930000 Total</b>					<b>111,434</b>	<b>8,847</b>	<b>55,452</b>	<b>6,127</b>	<b>6,043</b>	<b>31,275</b>	<b>3,691</b>	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	CA	31	31	-	-	-	-	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	IDU	50	-	-	-	-	-	50	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	OR	223	-	223	-	-	-	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	UT	902	-	-	-	-	902	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WA	28	-	-	28	-	-	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYP	95	-	-	-	95	-	-	-	-
<b>5931000 Total</b>					<b>1,328</b>	<b>31</b>	<b>223</b>	<b>28</b>	<b>95</b>	<b>902</b>	<b>50</b>	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	CA	460	460	-	-	-	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	IDU	995	-	-	-	-	-	995	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	OR	7,107	-	7,107	-	-	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	SNPD	23	1	6	1	2	11	1	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	UT	16,832	-	-	-	-	16,832	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WA	1,267	-	-	1,267	-	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYP	2,075	-	-	-	2,075	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYU	252	-	-	-	252	-	-	-	-
<b>5940000 Total</b>					<b>29,012</b>	<b>461</b>	<b>7,113</b>	<b>1,269</b>	<b>2,330</b>	<b>16,843</b>	<b>996</b>	-	-
5950000	MAINT LINE TRNSFRM	DNEX	Distribution O&M Expense	SNPD	1,101	39	291	70	106	536	58	-	-
<b>5950000 Total</b>					<b>1,101</b>	<b>39</b>	<b>291</b>	<b>70</b>	<b>106</b>	<b>536</b>	<b>58</b>	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	CA	48	48	-	-	-	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	IDU	65	-	-	-	-	-	65	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	OR	689	-	689	-	-	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	UT	597	-	-	-	-	597	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WA	37	-	-	37	-	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYP	371	-	-	-	371	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYU	61	-	-	-	61	-	-	-	-
<b>5960000 Total</b>					<b>1,868</b>	<b>48</b>	<b>689</b>	<b>37</b>	<b>432</b>	<b>597</b>	<b>65</b>	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	CA	16	16	-	-	-	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	IDU	34	-	-	-	-	-	34	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	OR	214	-	214	-	-	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	SNPD	27	1	7	2	3	13	1	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	UT	356	-	-	-	-	356	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WA	26	-	-	26	-	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYP	22	-	-	-	22	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYU	23	-	-	-	23	-	-	-	-
<b>5970000 Total</b>					<b>718</b>	<b>17</b>	<b>221</b>	<b>28</b>	<b>47</b>	<b>369</b>	<b>35</b>	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	CA	100	100	-	-	-	-	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	IDU	187	-	-	-	-	-	187	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	OR	(250)	-	(250)	-	-	-	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	SNPD	2,165	77	573	138	208	1,054	115	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	UT	809	-	-	-	-	809	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WA	209	-	-	209	-	-	-	-	-



Operations & Maintenance Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYP	374	-	-	-	374	-	-	-	-
<b>5980000 Total</b>					<b>3,595</b>	<b>177</b>	<b>323</b>	<b>347</b>	<b>582</b>	<b>1,863</b>	<b>302</b>	-	-
5989500	MNT DIST PLNT-ENV AM	DNEX	Distribution O&M Expense	SNPD	(7)	(0)	(2)	(0)	(1)	(3)	(0)	-	-
5989500	MNT DIST PLNT-ENV AM	DNEX	Distribution O&M Expense	SNPD	(7)	(0)	(2)	(0)	(1)	(3)	(0)	-	-
5989500	MNT DIST PLNT-ENV AM	DNEX	Distribution O&M Expense	SNPD	2,402	85	636	154	231	1,169	128	-	-
<b>5989500 Total</b>					<b>2,388</b>	<b>85</b>	<b>632</b>	<b>153</b>	<b>229</b>	<b>1,163</b>	<b>127</b>	-	-
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	CN	2,257	53	699	154	164	1,090	96	-	-
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	WYP	1	-	-	-	1	-	-	-	-
<b>9010000 Total</b>					<b>2,257</b>	<b>53</b>	<b>699</b>	<b>154</b>	<b>165</b>	<b>1,090</b>	<b>96</b>	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CA	408	408	-	-	-	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CN	389	9	120	27	28	188	16	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	IDU	2,035	-	-	-	-	-	2,035	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	OR	2,312	-	2,312	-	-	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	UT	5,735	-	-	-	-	5,735	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WA	1,197	-	-	1,197	-	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYP	1,007	-	-	-	1,007	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYU	189	-	-	-	-	189	-	-	-
<b>9020000 Total</b>					<b>13,271</b>	<b>417</b>	<b>2,432</b>	<b>1,224</b>	<b>1,225</b>	<b>5,923</b>	<b>2,051</b>	-	-
9030000	CUST RCRD/COLL EXP	CAEX	Customer Accounting Expense	CN	1,295	30	401	89	94	625	55	-	-
<b>9030000 Total</b>					<b>1,295</b>	<b>30</b>	<b>401</b>	<b>89</b>	<b>94</b>	<b>625</b>	<b>55</b>	-	-
9031000	CUST RCRD/CUST SYS	CAEX	Customer Accounting Expense	CN	2,546	60	789	174	185	1,229	108	-	-
<b>9031000 Total</b>					<b>2,546</b>	<b>60</b>	<b>789</b>	<b>174</b>	<b>185</b>	<b>1,229</b>	<b>108</b>	-	-
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	CN	8,631	202	2,675	591	628	4,169	366	-	-
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	OR	0	-	0	-	-	-	-	-	-
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	UT	(4)	-	-	-	-	(4)	-	-	-
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	WA	0	-	-	0	-	-	-	-	-
<b>9032000 Total</b>					<b>8,627</b>	<b>202</b>	<b>2,675</b>	<b>591</b>	<b>628</b>	<b>4,164</b>	<b>366</b>	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CA	17	17	-	-	-	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CN	13,185	309	4,086	902	960	6,368	559	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	IDU	300	-	-	-	-	-	300	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	OR	672	-	672	-	-	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	UT	1,425	-	-	-	-	1,425	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WA	188	-	-	188	-	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYP	446	-	-	-	446	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYU	63	-	-	-	63	-	-	-	-
<b>9033000 Total</b>					<b>16,297</b>	<b>326</b>	<b>4,758</b>	<b>1,091</b>	<b>1,469</b>	<b>7,793</b>	<b>860</b>	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	CA	8	8	-	-	-	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	IDU	16	-	-	-	-	-	16	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	OR	79	-	79	-	-	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	UT	58	-	-	-	-	58	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WA	12	-	-	12	-	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYP	16	-	-	-	16	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYU	8	-	-	-	8	-	-	-	-
<b>9035000 Total</b>					<b>197</b>	<b>8</b>	<b>79</b>	<b>12</b>	<b>24</b>	<b>58</b>	<b>16</b>	-	-
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	CN	13,573	318	4,206	929	988	6,555	576	-	-
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	OR	14	-	14	-	-	-	-	-	-
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	WA	51	-	-	51	-	-	-	-	-
<b>9036000 Total</b>					<b>13,637</b>	<b>318</b>	<b>4,220</b>	<b>979</b>	<b>988</b>	<b>6,555</b>	<b>576</b>	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CA	239	239	-	-	-	-	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CN	141	3	44	10	10	68	6	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	IDU	629	-	-	-	-	-	629	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	OR	5,875	-	5,875	-	-	-	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	UT	3,321	-	-	-	-	3,321	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WA	1,709	-	-	1,709	-	-	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WYP	72	-	-	-	72	-	-	-	-
<b>9040000 Total</b>					<b>11,986</b>	<b>243</b>	<b>5,918</b>	<b>1,719</b>	<b>82</b>	<b>3,389</b>	<b>635</b>	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	CA	(2)	(2)	-	-	-	-	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	IDU	0	-	-	-	-	-	0	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	OR	42	-	42	-	-	-	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	UT	(17)	-	-	-	-	(17)	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WA	14	-	-	14	-	-	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WYP	4	-	-	-	4	-	-	-	-
<b>9042000 Total</b>					<b>42</b>	<b>(2)</b>	<b>42</b>	<b>14</b>	<b>4</b>	<b>(17)</b>	<b>0</b>	-	-
9050000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	CN	25	1	8	2	2	12	1	-	-
<b>9050000 Total</b>					<b>25</b>	<b>1</b>	<b>8</b>	<b>2</b>	<b>2</b>	<b>12</b>	<b>1</b>	-	-



Operations & Maintenance Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9070000	SUPRV (CUST SERV)	CSEX	Customer Service Expense	CN	3	0	1	0	0	1	0	-	-
<b>9070000 Total</b>					<b>3</b>	<b>0</b>	<b>1</b>	<b>0</b>	<b>0</b>	<b>1</b>	<b>0</b>	<b>-</b>	<b>-</b>
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	CN	5	0	2	0	0	2	0	-	-
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	OR	1	-	1	-	-	-	-	-	-
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	UT	3	-	-	-	-	3	-	-	-
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	WA	3	-	-	3	-	-	-	-	-
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	WYP	1	-	-	-	1	-	-	-	-
<b>9080000 Total</b>					<b>13</b>	<b>0</b>	<b>3</b>	<b>3</b>	<b>1</b>	<b>5</b>	<b>0</b>	<b>-</b>	<b>-</b>
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	CN	855	20	265	59	62	413	36	-	-
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	OR	1,260	-	1,260	-	-	-	-	-	-
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	OTHER	270	-	-	-	-	-	-	-	270
<b>9081000 Total</b>					<b>2,386</b>	<b>20</b>	<b>1,525</b>	<b>59</b>	<b>62</b>	<b>413</b>	<b>36</b>	<b>-</b>	<b>270</b>
9084000	DSM DIRECT	CSEX	Customer Service Expense	CA	8	8	-	-	-	-	-	-	-
9084000	DSM DIRECT	CSEX	Customer Service Expense	CN	1,083	25	336	74	79	523	46	-	-
9084000	DSM DIRECT	CSEX	Customer Service Expense	IDU	17	-	-	-	-	-	17	-	-
9084000	DSM DIRECT	CSEX	Customer Service Expense	OTHER	51	-	-	-	-	-	-	-	51
9084000	DSM DIRECT	CSEX	Customer Service Expense	WA	10	-	-	10	-	-	-	-	-
<b>9084000 Total</b>					<b>1,169</b>	<b>33</b>	<b>336</b>	<b>84</b>	<b>79</b>	<b>523</b>	<b>62</b>	<b>-</b>	<b>51</b>
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	OTHER	80,711	-	-	-	-	-	-	-	80,711
<b>9085100 Total</b>					<b>80,711</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>80,711</b>
9086000	CUST SERV	CSEX	Customer Service Expense	CN	76	2	24	5	6	37	3	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	IDU	19	-	-	-	-	-	19	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	OR	2,210	-	2,210	-	-	-	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	UT	2,881	-	-	-	-	2,881	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	WA	294	-	-	294	-	-	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	WYP	951	-	-	-	951	-	-	-	-
<b>9086000 Total</b>					<b>6,431</b>	<b>2</b>	<b>2,234</b>	<b>299</b>	<b>957</b>	<b>2,918</b>	<b>22</b>	<b>-</b>	<b>-</b>
9089300	ENERGY STORAGE	CSEX	Customer Service Expense	OTHER	5	-	-	-	-	-	-	-	5
<b>9089300 Total</b>					<b>5</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>5</b>
9089500	BLUE SKY EXPENSE	CSEX	Customer Service Expense	OTHER	10,046	-	-	-	-	-	-	-	10,046
<b>9089500 Total</b>					<b>10,046</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>10,046</b>
9089600	SOLAR FEED-IN EXP	CSEX	Customer Service Expense	OTHER	10,005	-	-	-	-	-	-	-	10,005
<b>9089600 Total</b>					<b>10,005</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>10,005</b>
9089700	SUBSCRIBER SOLAR	CSEX	Customer Service Expense	UT	161	-	-	-	-	161	-	-	-
<b>9089700 Total</b>					<b>161</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>161</b>	<b>-</b>	<b>-</b>	<b>-</b>
9089800	COMMUNITY SOLAR	CSEX	Customer Service Expense	OTHER	460	-	-	-	-	-	-	-	460
<b>9089800 Total</b>					<b>460</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>460</b>
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CA	123	123	-	-	-	-	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CN	2,683	63	832	184	195	1,296	114	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	IDU	91	-	-	-	-	-	91	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	OR	680	-	680	-	-	-	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	UT	569	-	-	-	-	569	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WA	153	-	-	153	-	-	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WYP	340	-	-	-	340	-	-	-	-
<b>9090000 Total</b>					<b>4,638</b>	<b>186</b>	<b>1,511</b>	<b>336</b>	<b>535</b>	<b>1,865</b>	<b>205</b>	<b>-</b>	<b>-</b>
9100000	MISC CUST SERV/INF	CSEX	Customer Service Expense	CN	2	0	1	0	0	1	0	-	-
<b>9100000 Total</b>					<b>2</b>	<b>0</b>	<b>1</b>	<b>0</b>	<b>0</b>	<b>1</b>	<b>0</b>	<b>-</b>	<b>-</b>
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	OR	703	-	703	-	-	-	-	-	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	SO	76,468	1,686	20,779	5,870	10,053	33,596	4,467	16	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	UT	1,188	-	-	-	-	1,188	-	-	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	WA	0	-	-	0	-	-	-	-	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	WYP	395	-	-	-	395	-	-	-	-
<b>9200000 Total</b>					<b>78,753</b>	<b>1,686</b>	<b>21,481</b>	<b>5,870</b>	<b>10,448</b>	<b>34,784</b>	<b>4,467</b>	<b>16</b>	<b>-</b>
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CA	2	2	-	-	-	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CN	87	2	27	6	6	42	4	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	IDU	423	-	-	-	-	-	423	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	OR	1,811	-	1,811	-	-	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	SO	8,230	181	2,236	632	1,082	3,616	481	2	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	UT	78	-	-	-	-	78	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WA	8	-	-	8	-	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYP	19	-	-	-	19	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYU	5	-	-	-	5	-	-	-	-
<b>9210000 Total</b>					<b>10,663</b>	<b>186</b>	<b>4,074</b>	<b>645</b>	<b>1,112</b>	<b>3,736</b>	<b>908</b>	<b>2</b>	<b>-</b>
9220000	A&G EXP TRANSF-CR	AGEX	Administrative & General Expense	SO	(37,447)	(826)	(10,175)	(2,875)	(4,923)	(16,452)	(2,188)	(8)	-
<b>9220000 Total</b>					<b>(37,447)</b>	<b>(826)</b>	<b>(10,175)</b>	<b>(2,875)</b>	<b>(4,923)</b>	<b>(16,452)</b>	<b>(2,188)</b>	<b>(8)</b>	<b>-</b>



Operations & Maintenance Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	CA	81	81	-	-	-	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	IDU	1	-	-	-	-	-	1	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	OR	117	-	117	-	-	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	SO	13,730	303	3,731	1,054	1,805	6,032	802	3	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	UT	524	-	-	-	-	524	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WA	10	-	-	10	-	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYP	9	-	-	-	9	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYU	192	-	-	-	192	-	-	-	-
<b>9230000 Total</b>					<b>14,663</b>	<b>383</b>	<b>3,848</b>	<b>1,064</b>	<b>2,005</b>	<b>6,556</b>	<b>803</b>	<b>3</b>	-
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	CA	(1)	(1)	-	-	-	-	-	-	-
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	OR	113	-	113	-	-	-	-	-	-
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	SO	8,993	198	2,444	690	1,182	3,951	525	2	-
<b>9239990 Total</b>					<b>9,105</b>	<b>198</b>	<b>2,557</b>	<b>690</b>	<b>1,182</b>	<b>3,951</b>	<b>525</b>	<b>2</b>	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	CA	1,989	1,989	-	-	-	-	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	IDU	114	-	-	-	-	-	114	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	OR	7,836	-	7,836	-	-	-	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	UT	1,313	-	-	-	-	1,313	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	WA	572	-	-	572	-	-	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	WYP	350	-	-	-	350	-	-	-	-
<b>9241000 Total</b>					<b>12,173</b>	<b>1,989</b>	<b>7,836</b>	<b>572</b>	<b>350</b>	<b>1,313</b>	<b>114</b>	-	-
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	CA	(100)	(100)	-	-	-	-	-	-	-
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	OR	(388)	-	(388)	-	-	-	-	-	-
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	WA	(20)	-	-	(20)	-	-	-	-	-
<b>9242000 Total</b>					<b>(508)</b>	<b>(100)</b>	<b>(388)</b>	<b>(20)</b>	-	-	-	-	-
9243000	PROP INS - PREMIUMS	AGEX	Administrative & General Expense	SO	4,372	96	1,188	336	575	1,921	255	1	-
<b>9243000 Total</b>					<b>4,372</b>	<b>96</b>	<b>1,188</b>	<b>336</b>	<b>575</b>	<b>1,921</b>	<b>255</b>	<b>1</b>	-
9250000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	153,085	3,376	41,598	11,752	20,126	67,259	8,944	32	-
<b>9250000 Total</b>					<b>153,085</b>	<b>3,376</b>	<b>41,598</b>	<b>11,752</b>	<b>20,126</b>	<b>67,259</b>	<b>8,944</b>	<b>32</b>	-
9251000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	OR	1,485	-	1,485	-	-	-	-	-	-
9251000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	(1,485)	(33)	(403)	(114)	(195)	(652)	(87)	(0)	-
<b>9251000 Total</b>					-	<b>(33)</b>	<b>1,081</b>	<b>(114)</b>	<b>(195)</b>	<b>(652)</b>	<b>(87)</b>	<b>(0)</b>	-
9261200	PEN EXP-OTH NBC	AGEX	Administrative & General Expense	SO	(6,607)	(146)	(1,795)	(507)	(869)	(2,903)	(386)	(1)	-
<b>9261200 Total</b>					<b>(6,607)</b>	<b>(146)</b>	<b>(1,795)</b>	<b>(507)</b>	<b>(869)</b>	<b>(2,903)</b>	<b>(386)</b>	<b>(1)</b>	-
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	CA	26	26	-	-	-	-	-	-	-
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	WA	73	-	-	73	-	-	-	-	-
<b>9261500 Total</b>					<b>99</b>	<b>26</b>	-	<b>73</b>	-	-	-	-	-
9262200	POSTRET EXP-OTH NBC	AGEX	Administrative & General Expense	SO	(2,873)	(63)	(781)	(221)	(378)	(1,262)	(168)	(1)	-
<b>9262200 Total</b>					<b>(2,873)</b>	<b>(63)</b>	<b>(781)</b>	<b>(221)</b>	<b>(378)</b>	<b>(1,262)</b>	<b>(168)</b>	<b>(1)</b>	-
9262500	POSTRET EXP-ST SITUS	AGEX	Administrative & General Expense	OR	164	-	164	-	-	-	-	-	-
9262500	POSTRET EXP-ST SITUS	AGEX	Administrative & General Expense	UT	5,401	-	-	-	-	5,401	-	-	-
<b>9262500 Total</b>					<b>5,565</b>	-	<b>164</b>	-	-	<b>5,401</b>	-	-	-
9263200	SERP EXP-OTH NBC	AGEX	Administrative & General Expense	SO	2,768	61	752	212	364	1,216	162	1	-
<b>9263200 Total</b>					<b>2,768</b>	<b>61</b>	<b>752</b>	<b>212</b>	<b>364</b>	<b>1,216</b>	<b>162</b>	<b>1</b>	-
9269100	GROSS-UP - PENSION	AGEX	Administrative & General Expense	SO	8,149	180	2,214	626	1,071	3,580	476	2	-
<b>9269100 Total</b>					<b>8,149</b>	<b>180</b>	<b>2,214</b>	<b>626</b>	<b>1,071</b>	<b>3,580</b>	<b>476</b>	<b>2</b>	-
9269200	GROSS-UP - POST-RETR	AGEX	Administrative & General Expense	SO	947	21	257	73	125	416	55	0	-
<b>9269200 Total</b>					<b>947</b>	<b>21</b>	<b>257</b>	<b>73</b>	<b>125</b>	<b>416</b>	<b>55</b>	<b>0</b>	-
9269400	GROSS-UP - MD/DN/VL	AGEX	Administrative & General Expense	SO	60,432	1,333	16,421	4,639	7,945	26,551	3,531	12	-
<b>9269400 Total</b>					<b>60,432</b>	<b>1,333</b>	<b>16,421</b>	<b>4,639</b>	<b>7,945</b>	<b>26,551</b>	<b>3,531</b>	<b>12</b>	-
9269500	GROSS-UP - 401(K) EX	AGEX	Administrative & General Expense	SO	39,571	873	10,753	3,038	5,202	17,386	2,312	8	-
<b>9269500 Total</b>					<b>39,571</b>	<b>873</b>	<b>10,753</b>	<b>3,038</b>	<b>5,202</b>	<b>17,386</b>	<b>2,312</b>	<b>8</b>	-
9269600	GROSS-UP - POST-EMPL	AGEX	Administrative & General Expense	SO	6,401	141	1,739	491	842	2,812	374	1	-
<b>9269600 Total</b>					<b>6,401</b>	<b>141</b>	<b>1,739</b>	<b>491</b>	<b>842</b>	<b>2,812</b>	<b>374</b>	<b>1</b>	-
9269700	GROSS-UP - OTH BEN E	AGEX	Administrative & General Expense	SO	5,779	127	1,570	444	760	2,539	338	1	-
<b>9269700 Total</b>					<b>5,779</b>	<b>127</b>	<b>1,570</b>	<b>444</b>	<b>760</b>	<b>2,539</b>	<b>338</b>	<b>1</b>	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	CA	480	480	-	-	-	-	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	IDU	204	-	-	-	-	-	204	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	OR	2,021	-	2,021	-	-	-	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	SO	2,240	49	609	172	294	984	131	0	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	UT	868	-	-	-	-	868	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WA	123	-	-	123	-	-	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WYP	1,138	-	-	-	1,138	-	-	-	-
<b>9280000 Total</b>					<b>7,074</b>	<b>530</b>	<b>2,629</b>	<b>295</b>	<b>1,433</b>	<b>1,852</b>	<b>335</b>	<b>0</b>	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	CA	78	78	-	-	-	-	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	IDU	723	-	-	-	-	-	723	-	-



Operations & Maintenance Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	OR	3,778	-	3,778	-	-	-	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	UT	6,221	-	-	-	-	6,221	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WA	674	-	-	674	-	-	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WYP	1,830	-	-	-	1,830	-	-	-	-
<b>9282000 Total</b>					<b>13,305</b>	<b>78</b>	<b>3,778</b>	<b>674</b>	<b>1,830</b>	<b>6,221</b>	<b>723</b>	-	-
9283000	FERC FILING FEE	AGEX	Administrative & General Expense	SG	4,290	63	1,118	336	609	1,904	258	1	-
<b>9283000 Total</b>					<b>4,290</b>	<b>63</b>	<b>1,118</b>	<b>336</b>	<b>609</b>	<b>1,904</b>	<b>258</b>	<b>1</b>	-
9290000	DUPLICATE CHRGS-CR	AGEX	Administrative & General Expense	SO	(3,458)	(76)	(940)	(265)	(455)	(1,519)	(202)	(1)	-
<b>9290000 Total</b>					<b>(3,458)</b>	<b>(76)</b>	<b>(940)</b>	<b>(265)</b>	<b>(455)</b>	<b>(1,519)</b>	<b>(202)</b>	<b>(1)</b>	-
9299100	DUP CHG CR - PENSION	AGEX	Administrative & General Expense	SO	(8,149)	(180)	(2,214)	(626)	(1,071)	(3,580)	(476)	(2)	-
<b>9299100 Total</b>					<b>(8,149)</b>	<b>(180)</b>	<b>(2,214)</b>	<b>(626)</b>	<b>(1,071)</b>	<b>(3,580)</b>	<b>(476)</b>	<b>(2)</b>	-
9299200	DUP CHG CR - POST-RT	AGEX	Administrative & General Expense	SO	(947)	(21)	(257)	(73)	(125)	(416)	(55)	(0)	-
<b>9299200 Total</b>					<b>(947)</b>	<b>(21)</b>	<b>(257)</b>	<b>(73)</b>	<b>(125)</b>	<b>(416)</b>	<b>(55)</b>	<b>(0)</b>	-
9299400	DUP CHG CR - M/D/V/L	AGEX	Administrative & General Expense	SO	(60,432)	(1,333)	(16,421)	(4,639)	(7,945)	(26,551)	(3,531)	(12)	-
<b>9299400 Total</b>					<b>(60,432)</b>	<b>(1,333)</b>	<b>(16,421)</b>	<b>(4,639)</b>	<b>(7,945)</b>	<b>(26,551)</b>	<b>(3,531)</b>	<b>(12)</b>	-
9299500	DUP CHG CR - 401(K)	AGEX	Administrative & General Expense	SO	(39,571)	(873)	(10,753)	(3,038)	(5,202)	(17,386)	(2,312)	(8)	-
<b>9299500 Total</b>					<b>(39,571)</b>	<b>(873)</b>	<b>(10,753)</b>	<b>(3,038)</b>	<b>(5,202)</b>	<b>(17,386)</b>	<b>(2,312)</b>	<b>(8)</b>	-
9299600	DUP CHG CR - POST-EM	AGEX	Administrative & General Expense	SO	(6,401)	(141)	(1,739)	(491)	(842)	(2,812)	(374)	(1)	-
<b>9299600 Total</b>					<b>(6,401)</b>	<b>(141)</b>	<b>(1,739)</b>	<b>(491)</b>	<b>(842)</b>	<b>(2,812)</b>	<b>(374)</b>	<b>(1)</b>	-
9299700	DUP CHG CR - OTH BEN	AGEX	Administrative & General Expense	SO	(5,779)	(127)	(1,570)	(444)	(760)	(2,539)	(338)	(1)	-
<b>9299700 Total</b>					<b>(5,779)</b>	<b>(127)</b>	<b>(1,570)</b>	<b>(444)</b>	<b>(760)</b>	<b>(2,539)</b>	<b>(338)</b>	<b>(1)</b>	-
9301000	GEN ADVERTISNG EXP	AGEX	Administrative & General Expense	SO	18	0	5	1	2	8	1	0	-
<b>9301000 Total</b>					<b>18</b>	<b>0</b>	<b>5</b>	<b>1</b>	<b>2</b>	<b>8</b>	<b>1</b>	<b>0</b>	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	OR	0	-	0	-	-	-	-	-	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	SO	2,228	49	605	171	293	979	130	0	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	UT	3	-	-	-	-	3	-	-	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	WYP	19	-	-	-	19	-	-	-	-
<b>9302000 Total</b>					<b>2,250</b>	<b>49</b>	<b>606</b>	<b>171</b>	<b>312</b>	<b>982</b>	<b>130</b>	<b>0</b>	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	CA	51	51	-	-	-	-	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	IDU	1	-	-	-	-	-	1	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	OR	455	-	455	-	-	-	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	SO	2,061	45	560	158	271	905	120	0	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	UT	369	-	-	-	-	369	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WA	10	-	-	10	-	-	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WYP	146	-	-	-	146	-	-	-	-
<b>9310000 Total</b>					<b>3,093</b>	<b>96</b>	<b>1,015</b>	<b>169</b>	<b>417</b>	<b>1,275</b>	<b>121</b>	<b>0</b>	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CA	117	117	-	-	-	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CN	28	1	9	2	2	13	1	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	IDU	6	-	-	-	-	-	6	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	OR	150	-	150	-	-	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	SO	26,097	575	7,091	2,003	3,431	11,466	1,525	5	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	UT	33	-	-	-	-	33	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WA	74	-	-	74	-	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYP	10	-	-	-	10	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYU	3	-	-	-	3	-	-	-	-
<b>9350000 Total</b>					<b>26,517</b>	<b>693</b>	<b>7,250</b>	<b>2,079</b>	<b>3,446</b>	<b>11,512</b>	<b>1,532</b>	<b>5</b>	-
9359500	MAINT GEN PLT-ENV AM	AGEX	Administrative & General Expense	SO	22	0	6	2	3	10	1	0	-
<b>9359500 Total</b>					<b>22</b>	<b>0</b>	<b>6</b>	<b>2</b>	<b>3</b>	<b>10</b>	<b>1</b>	<b>0</b>	-
<b>Grand Total</b>					<b>3,092,164</b>	<b>57,174</b>	<b>814,402</b>	<b>220,908</b>	<b>408,582</b>	<b>1,303,434</b>	<b>181,333</b>	<b>791</b>	<b>105,540</b>

**B3.**  
**DEPRECIATION**  
**EXPENSE**



Depreciation Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3102000	LAND RIGHTS	SG	810	12	211	63	115	360	49	0	-
4030000	DEPN EXPENSE-ELECT	3110000	STRUCTURES AND IMPROVEMENTS	SG	36,945	542	9,632	2,896	5,244	16,402	2,219	11	-
4030000	DEPN EXPENSE-ELECT	3120000	BOILER PLANT EQUIPMENT	SG	199,347	2,925	51,970	15,627	28,294	88,500	11,973	58	-
4030000	DEPN EXPENSE-ELECT	3140000	TURBOGENERATOR UNITS	SG	41,422	608	10,799	3,247	5,879	18,389	2,488	12	-
4030000	DEPN EXPENSE-ELECT	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	16,451	241	4,289	1,290	2,335	7,304	988	5	-
4030000	DEPN EXPENSE-ELECT	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	2	0	0	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELECT	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	1,534	23	400	120	218	681	92	0	-
4030000	DEPN EXPENSE-ELECT	3302000	LAND RIGHTS	SG-P	72	1	19	6	10	32	4	0	-
4030000	DEPN EXPENSE-ELECT	3302000	LAND RIGHTS	SG-U	24	0	6	2	3	11	1	0	-
4030000	DEPN EXPENSE-ELECT	3303000	WATER RIGHTS	SG-P	0	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELECT	3303000	WATER RIGHTS	SG-U	2	0	0	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELECT	3304000	FLOOD RIGHTS	SG-P	13	0	3	1	2	6	1	0	-
4030000	DEPN EXPENSE-ELECT	3304000	FLOOD RIGHTS	SG-U	4	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELECT	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	2	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELECT	3310000	STRUCTURES AND IMPROVE	SG-P	23	0	6	2	3	10	1	0	-
4030000	DEPN EXPENSE-ELECT	3310000	STRUCTURES AND IMPROVE	SG-U	263	4	68	21	37	117	16	0	-
4030000	DEPN EXPENSE-ELECT	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	454	7	118	36	64	202	27	0	-
4030000	DEPN EXPENSE-ELECT	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	341	5	89	27	48	151	20	0	-
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	9,512	140	2,480	746	1,350	4,223	571	3	-
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	22	0	6	2	3	10	1	0	-
4030000	DEPN EXPENSE-ELECT	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	897	13	234	70	127	398	54	0	-
4030000	DEPN EXPENSE-ELECT	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	57	1	15	4	8	25	3	0	-
4030000	DEPN EXPENSE-ELECT	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	101	1	26	8	14	45	6	0	-
4030000	DEPN EXPENSE-ELECT	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	1,003	15	262	79	142	445	60	0	-
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	13,169	193	3,433	1,032	1,869	5,847	791	4	-
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	3,627	53	946	284	515	1,610	218	1	-
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF"	SG-P	7,790	114	2,031	611	1,106	3,458	468	2	-
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF"	SG-U	15	0	4	1	2	7	1	0	-
4030000	DEPN EXPENSE-ELECT	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	4	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELECT	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	2	0	0	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	(4,406)	(65)	(1,149)	(345)	(625)	(1,956)	(265)	(1)	-
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	2,087	31	544	164	296	927	125	1	-
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	(5,370)	(79)	(1,400)	(421)	(762)	(2,384)	(323)	(2)	-
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	632	9	165	50	90	281	38	0	-
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	(1,049)	(15)	(273)	(82)	(149)	(466)	(63)	(0)	-
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	4	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELECT	3350000	MISC POWER PLANT EQUIP	SG-U	5	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELECT	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	1	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	426	6	111	33	60	189	26	0	-
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	114	2	30	9	16	50	7	0	-
4030000	DEPN EXPENSE-ELECT	3402000	LAND RIGHTS	SG	184	3	48	14	26	82	11	0	-
4030000	DEPN EXPENSE-ELECT	3410000	STRUCTURES & IMPROVEMENTS	SG	7,128	105	1,858	559	1,012	3,165	428	2	-
4030000	DEPN EXPENSE-ELECT	3410000	STRUCTURES & IMPROVEMENTS	UT	1	-	-	-	-	1	-	-	-
4030000	DEPN EXPENSE-ELECT	3420000	"FUEL HOLDERS, PRODUCERS, ACCES"	SG	519	8	135	41	74	230	31	0	-
4030000	DEPN EXPENSE-ELECT	3430000	PRIME MOVERS	SG	125,254	1,838	32,654	9,819	17,778	55,606	7,523	37	-
4030000	DEPN EXPENSE-ELECT	3440000	GENERATORS	SG	18,779	276	4,896	1,472	2,665	8,337	1,128	5	-
4030000	DEPN EXPENSE-ELECT	3440000	GENERATORS	UT	3	-	-	-	-	3	-	-	-
4030000	DEPN EXPENSE-ELECT	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	11,241	165	2,930	881	1,595	4,990	675	3	-
4030000	DEPN EXPENSE-ELECT	3450000	ACCESSORY ELECTRIC EQUIPMENT	UT	1	-	-	-	-	1	-	-	-
4030000	DEPN EXPENSE-ELECT	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	589	9	154	46	84	261	35	0	-
4030000	DEPN EXPENSE-ELECT	3502000	LAND RIGHTS	SG	2,724	40	710	214	387	1,209	164	1	-
4030000	DEPN EXPENSE-ELECT	3520000	STRUCTURES & IMPROVEMENTS	SG	4,190	61	1,092	328	595	1,860	252	1	-
4030000	DEPN EXPENSE-ELECT	3530000	STATION EQUIPMENT	SG	36,727	539	9,575	2,879	5,213	16,305	2,206	11	-
4030000	DEPN EXPENSE-ELECT	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	2,938	43	766	230	417	1,304	176	1	-
4030000	DEPN EXPENSE-ELECT	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	406	6	106	32	58	180	24	0	-
4030000	DEPN EXPENSE-ELECT	3540000	TOWERS AND FIXTURES	SG	19,676	289	5,130	1,542	2,793	8,735	1,182	6	-
4030000	DEPN EXPENSE-ELECT	3550000	POLLS AND FIXTURES	SG	22,835	335	5,953	1,790	3,241	10,138	1,371	7	-
4030000	DEPN EXPENSE-ELECT	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	24,728	363	6,447	1,938	3,510	10,978	1,485	7	-
4030000	DEPN EXPENSE-ELECT	3570000	UNDERGROUND CONDUIT	SG	61	1	16	5	9	27	4	0	-
4030000	DEPN EXPENSE-ELECT	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	148	2	39	12	21	66	9	0	-
4030000	DEPN EXPENSE-ELECT	3590000	ROADS AND TRAILS	SG	154	2	40	12	22	68	9	0	-
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	CA	12	12	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	IDU	24	-	-	-	-	-	24	-	-
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	OR	61	-	61	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	UT	179	-	-	-	-	179	-	-	-
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WA	8	-	-	8	-	-	-	-	-



Depreciation Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WYP	60	-	-	-	60	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WYU	76	-	-	-	76	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	CA	98	98	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	IDU	54	-	-	-	-	-	54	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	OR	545	-	545	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	UT	1,059	-	-	-	-	1,059	-	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WA	106	-	-	106	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WYP	212	-	-	-	212	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WYU	84	-	-	-	84	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	CA	739	739	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	IDU	739	-	-	-	-	-	739	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	OR	5,098	-	5,098	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	UT	11,229	-	-	-	-	11,229	-	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WA	1,674	-	-	1,674	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WYP	2,269	-	-	-	2,269	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WYU	353	-	-	-	353	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	10	10	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	11	-	-	-	-	-	11	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	82	-	82	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	167	-	-	-	-	167	-	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	28	-	-	28	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	37	-	-	-	37	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	4	-	-	-	4	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	CA	2,724	2,724	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	IDU	3,466	-	-	-	-	-	3,466	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	OR	13,886	-	13,886	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	UT	15,230	-	-	-	-	15,230	-	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WA	4,075	-	-	4,075	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WYP	5,360	-	-	-	5,360	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WYU	1,073	-	-	-	1,073	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	913	913	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	1,000	-	-	-	-	-	1,000	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	6,876	-	6,876	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	6,989	-	-	-	-	6,989	-	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	1,982	-	-	1,982	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	2,673	-	-	-	2,673	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	350	-	-	-	350	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	CA	460	460	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	IDU	268	-	-	-	-	-	268	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	OR	1,945	-	1,945	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	UT	5,519	-	-	-	-	5,519	-	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WA	513	-	-	513	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WYP	837	-	-	-	837	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WYU	158	-	-	-	158	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	533	533	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	634	-	-	-	-	-	634	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	4,184	-	4,184	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	13,443	-	-	-	-	13,443	-	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	741	-	-	741	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	1,443	-	-	-	1,443	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	553	-	-	-	553	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	CA	1,290	1,290	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	IDU	1,969	-	-	-	-	-	1,969	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	OR	11,544	-	11,544	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	UT	13,914	-	-	-	-	13,914	-	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WA	3,017	-	-	3,017	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WYP	3,489	-	-	-	3,489	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WYU	489	-	-	-	489	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	CA	252	252	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	IDU	214	-	-	-	-	-	214	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	OR	2,222	-	2,222	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	UT	2,240	-	-	-	-	2,240	-	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WA	564	-	-	564	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WYP	397	-	-	-	397	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WYU	87	-	-	-	87	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	CA	388	388	-	-	-	-	-	-	-





Depreciation Expense (Actuals)  
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Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	IDU	851	-	-	-	-	-	851	-	-
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	OR	4,746	-	4,746	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	UT	6,191	-	-	-	-	6,191	-	-	-
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WA	1,165	-	-	1,165	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WYP	1,052	-	-	-	1,052	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WYU	366	-	-	-	366	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	CA	294	294	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	IDU	721	-	-	-	-	-	721	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	OR	2,574	-	2,574	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	UT	4,768	-	-	-	-	4,768	-	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WA	639	-	-	639	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WYP	655	-	-	-	655	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WYU	121	-	-	-	121	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	CA	15	15	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	9	-	-	-	-	-	9	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	OR	122	-	122	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	UT	267	-	-	-	-	267	-	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WA	19	-	-	19	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	40	-	-	-	40	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	8	-	-	-	8	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	28	28	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	36	-	-	-	-	-	36	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	664	-	664	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	1,106	-	-	-	-	1,106	-	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	110	-	-	110	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	241	-	-	-	241	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	64	-	-	-	64	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	IDU	0	-	-	-	-	-	0	-	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	OR	0	-	0	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	SG	0	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	SO	2	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	UT	2	-	-	-	-	2	-	-	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	WYP	1	-	-	-	1	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	WYU	0	-	-	-	0	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	CA	69	69	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	CN	167	4	52	11	12	81	7	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	IDU	201	-	-	-	-	-	201	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	OR	684	-	684	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SE	18	0	4	1	3	8	1	0	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SG	205	3	54	16	29	91	12	0	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SO	1,942	43	528	149	255	853	113	0	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	UT	941	-	-	-	-	941	-	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WA	265	-	-	265	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WYP	213	-	-	-	213	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WYU	103	-	-	-	103	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	CA	5	5	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	CN	42	1	13	3	3	20	2	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	IDU	5	-	-	-	-	-	5	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	OR	74	-	74	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SE	0	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SG	79	1	21	6	11	35	5	0	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SO	575	13	156	44	76	253	34	0	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	UT	42	-	-	-	-	42	-	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WA	4	-	-	4	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WYP	26	-	-	-	26	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WYU	2	-	-	-	2	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	7	7	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	588	14	182	40	43	284	25	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	78	-	-	-	-	-	78	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	181	-	181	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	5	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	479	7	125	38	68	213	29	0	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	9,187	203	2,496	705	1,208	4,036	537	2	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	144	-	-	-	-	144	-	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	63	-	-	63	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	341	-	-	-	341	-	-	-	-



Depreciation Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	13	-	-	-	13	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	CN	0	0	0	0	0	0	0	-	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	IDU	0	-	-	-	-	-	0	-	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	OR	0	-	0	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	SG	6	0	2	0	1	3	0	0	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	SO	15	0	4	1	2	7	1	0	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	UT	1	-	-	-	-	1	-	-	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	WYP	0	-	-	-	0	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	WYU	1	-	-	-	1	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	CA	7	7	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	IDU	23	-	-	-	-	-	23	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	OR	107	-	107	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	SG	237	3	62	19	34	105	14	0	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	SO	10	0	3	1	1	4	1	0	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	UT	140	-	-	-	-	140	-	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WA	27	-	-	27	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WYP	50	-	-	-	50	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WYU	0	-	-	-	0	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	33	33	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	90	-	-	-	-	-	90	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	450	-	450	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	4	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	925	14	241	72	131	410	56	0	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	82	2	22	6	11	36	5	0	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	631	-	-	-	-	631	-	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	109	-	-	109	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	160	-	-	-	160	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	16	-	-	-	16	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	CA	21	21	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	IDU	65	-	-	-	-	-	65	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	OR	465	-	465	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SE	61	1	15	5	9	27	4	0	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SG	321	5	84	25	46	142	19	0	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SO	243	5	66	19	32	107	14	0	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	UT	387	-	-	-	-	387	-	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WA	73	-	-	73	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WYP	133	-	-	-	133	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WYU	5	-	-	-	5	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	CA	257	257	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	CN	165	4	51	11	12	80	7	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	IDU	495	-	-	-	-	-	495	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	OR	3,306	-	3,306	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SE	12	0	3	1	2	5	1	0	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SG	7,728	113	2,015	606	1,097	3,431	464	2	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SO	4,099	90	1,114	315	539	1,801	239	1	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	UT	2,637	-	-	-	-	2,637	-	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WA	506	-	-	506	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WYP	997	-	-	-	997	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WYU	254	-	-	-	254	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	CA	27	27	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	IDU	27	-	-	-	-	-	27	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	OR	219	-	219	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SE	7	0	2	1	1	3	0	0	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SG	357	5	93	28	51	158	21	0	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SO	44	1	12	3	6	19	3	0	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	UT	169	-	-	-	-	169	-	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WA	44	-	-	44	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WYP	54	-	-	-	54	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WYU	9	-	-	-	9	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	CA	3	3	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	CN	4	0	1	0	0	2	0	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	IDU	4	-	-	-	-	-	4	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	OR	61	-	61	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SE	0	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SG	141	2	37	11	20	62	8	0	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SO	110	2	30	8	14	48	6	0	-



Depreciation Expense (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	UT	69	-	-	-	-	69	-	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WA	9	-	-	9	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WYP	12	-	-	-	12	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WYU	1	-	-	-	1	-	-	-	-
<b>4030000 Total</b>					<b>839,912</b>	<b>17,594</b>	<b>225,216</b>	<b>65,285</b>	<b>114,477</b>	<b>368,227</b>	<b>48,929</b>	<b>183</b>	<b>-</b>
4032000	DEPR - STEAM	565131	DEPR - PROD STEAM NOT CLASSIFIED	SG	9,065	133	2,363	711	1,287	4,024	544	3	-
4032000	DEPR - STEAM	565247	Depr - Prod Steam UT STEP	OTHER	180,756	-	-	-	-	-	-	-	180,756
<b>4032000 Total</b>					<b>189,821</b>	<b>133</b>	<b>2,363</b>	<b>711</b>	<b>1,287</b>	<b>4,024</b>	<b>544</b>	<b>3</b>	<b>180,756</b>
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-P	872	13	227	68	124	387	52	0	-
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-U	82	1	21	6	12	36	5	0	-
<b>4033000 Total</b>					<b>954</b>	<b>14</b>	<b>249</b>	<b>75</b>	<b>135</b>	<b>424</b>	<b>57</b>	<b>0</b>	<b>-</b>
4034000	DEPR - OTHER	565134	DEPR - PROD OTHER NOT CLASSIFIED	SG	249	4	65	20	35	111	15	0	-
<b>4034000 Total</b>					<b>249</b>	<b>4</b>	<b>65</b>	<b>20</b>	<b>35</b>	<b>111</b>	<b>15</b>	<b>0</b>	<b>-</b>
4035000	DEPR-TRANSMISSION	565141	DEPR - TRANS ASSETS NOT CLASSIFIED	SG	10,800	158	2,816	847	1,533	4,795	649	3	-
<b>4035000 Total</b>					<b>10,800</b>	<b>158</b>	<b>2,816</b>	<b>847</b>	<b>1,533</b>	<b>4,795</b>	<b>649</b>	<b>3</b>	<b>-</b>
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	CA	101	101	-	-	-	-	-	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	IDU	(1,045)	-	-	-	-	-	(1,045)	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	OR	974	-	974	-	-	-	-	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	UT	(10,026)	-	-	-	-	(10,026)	-	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WA	544	-	-	544	-	-	-	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WYP	(647)	-	-	-	(647)	-	-	-	-
<b>4036000 Total</b>					<b>(10,099)</b>	<b>101</b>	<b>974</b>	<b>544</b>	<b>(647)</b>	<b>(10,026)</b>	<b>(1,045)</b>	<b>-</b>	<b>-</b>
4037000	DEPR - GENERAL	565201	DEPR - GEN ASSETS NOT CLASSIFIED	SG	3,666	54	956	287	520	1,627	220	1	-
<b>4037000 Total</b>					<b>3,666</b>	<b>54</b>	<b>956</b>	<b>287</b>	<b>520</b>	<b>1,627</b>	<b>220</b>	<b>1</b>	<b>-</b>
4039999	DEPR EXP-ELEC, OTH	565970	DEPRECIATION-JOINT OWNER BILLED-CREDIT	SG	(222)	(3)	(58)	(17)	(31)	(98)	(13)	(0)	-
<b>4039999 Total</b>					<b>(222)</b>	<b>(3)</b>	<b>(58)</b>	<b>(17)</b>	<b>(31)</b>	<b>(98)</b>	<b>(13)</b>	<b>(0)</b>	<b>-</b>
<b>Grand Total</b>					<b>1,035,081</b>	<b>18,055</b>	<b>232,581</b>	<b>67,750</b>	<b>117,309</b>	<b>369,083</b>	<b>49,356</b>	<b>191</b>	<b>180,756</b>

# **B4. AMORTIZATION EXPENSE**



**Amortization Expense (Actuals)**  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	IDU	20	-	-	-	-	-	20	-	-
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG	631	9	165	49	90	280	38	0	-
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-P	2,680	39	699	210	380	1,190	161	1	-
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-U	306	4	80	24	43	136	18	0	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	OR	9	-	9	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	SG	996	15	260	78	141	442	60	0	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	UT	34	-	-	-	-	34	-	-	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	WYP	59	-	-	-	59	-	-	-	-
4040000	AMOR LTD TRM PLNT	3031050	RWT - RCMS WORK TRACKING	SO	58	1	16	4	8	26	3	0	-
4040000	AMOR LTD TRM PLNT	3031830	CUSTOMER SERVICE SYSTEM	CN	6,196	145	1,920	424	451	2,993	263	-	-
4040000	AMOR LTD TRM PLNT	3032040	SAP	SO	3,965	87	1,077	304	521	1,742	232	1	-
4040000	AMOR LTD TRM PLNT	3032130	PROD & TRANS PLANT	SG	109	2	28	9	15	48	7	0	-
4040000	AMOR LTD TRM PLNT	3032140	MINING PLANT	SO	76	2	21	6	10	33	4	0	-
4040000	AMOR LTD TRM PLNT	3032150	HYDRO PLANT	SO	128	3	35	10	17	56	8	0	-
4040000	AMOR LTD TRM PLNT	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	23	1	6	2	3	10	1	0	-
4040000	AMOR LTD TRM PLNT	3032360	2002 GRID NET POWER COST MODELING	SO	5	0	1	0	1	2	0	0	-
4040000	AMOR LTD TRM PLNT	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	11	0	3	1	1	5	1	0	-
4040000	AMOR LTD TRM PLNT	3032600	SINGLE PERSON SCHEDULING	SO	35	1	10	3	5	15	2	0	-
4040000	AMOR LTD TRM PLNT	3032640	TIBCO SOFTWARE	SO	392	9	106	30	51	172	23	0	-
4040000	AMOR LTD TRM PLNT	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	4	0	1	0	1	2	0	0	-
4040000	AMOR LTD TRM PLNT	3032690	UTILITY INTERNATIONAL FORECASTING MODEL	SO	470	10	128	36	62	206	27	0	-
4040000	AMOR LTD TRM PLNT	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	7	0	2	1	1	3	0	0	-
4040000	AMOR LTD TRM PLNT	3032740	GADSBY INTANGIBLE ASSETS	SG	4	0	1	0	1	2	0	0	-
4040000	AMOR LTD TRM PLNT	3032760	SWIFT 2 IMPROVEMENTS	SG	432	6	113	34	61	192	26	0	-
4040000	AMOR LTD TRM PLNT	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	24	0	6	2	3	11	1	0	-
4040000	AMOR LTD TRM PLNT	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	5	0	1	0	1	2	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	3032830	VCPRO - XEROX CUST STMT FRMTR ENHANCE -	SO	71	2	19	5	9	31	4	0	-
4040000	AMOR LTD TRM PLNT	3032860	WEB SOFTWARE	SO	1,857	41	505	143	244	816	109	0	-
4040000	AMOR LTD TRM PLNT	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	360	5	94	28	51	160	22	0	-
4040000	AMOR LTD TRM PLNT	3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO	297	7	81	23	39	130	17	0	-
4040000	AMOR LTD TRM PLNT	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	2,823	41	736	221	401	1,253	170	1	-
4040000	AMOR LTD TRM PLNT	3033170	GTX VERSION 7 SOFTWARE	CN	2,003	47	621	137	146	968	85	-	-
4040000	AMOR LTD TRM PLNT	3033220	MONARCH EMS/SCADA	SO	2,965	65	806	228	390	1,303	173	1	-
4040000	AMOR LTD TRM PLNT	3033230	VREALIZE VMWARE - SHARED	SO	202	4	55	16	27	89	12	0	-
4040000	AMOR LTD TRM PLNT	3033240	IEE - Itron Enterprise Addition	CN	1,126	26	349	77	82	544	48	-	-
4040000	AMOR LTD TRM PLNT	3033250	AMI Metering Software	CN	3,550	83	1,100	243	258	1,715	151	-	-
4040000	AMOR LTD TRM PLNT	3033260	Big Data & Analytics	SO	771	17	209	59	101	339	45	0	-
4040000	AMOR LTD TRM PLNT	3033270	CES - Customer Experience System	CN	558	13	173	38	41	270	24	-	-
4040000	AMOR LTD TRM PLNT	3033280	MAPAPPS - Mapping Systems Application	SO	163	4	44	13	21	72	10	0	-
4040000	AMOR LTD TRM PLNT	3033290	CUSTOMER CONTACTS	CN	94	2	29	6	7	46	4	-	-
4040000	AMOR LTD TRM PLNT	3033310	C&T - ENERGY TRADING SYSTEM	SO	2,273	50	618	174	299	999	133	0	-
4040000	AMOR LTD TRM PLNT	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SO	36	1	10	3	5	16	2	0	-
4040000	AMOR LTD TRM PLNT	3033370	DISTRIBUTION INTANGIBLES	WYP	4	-	-	-	4	-	-	-	-
4040000	AMOR LTD TRM PLNT	3033390	RMT TRADE SYSTEM	SO	91	2	25	7	12	40	5	0	-
4040000	AMOR LTD TRM PLNT	3033410	M365	SO	31	1	8	2	4	14	2	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	CA	2	2	-	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	CN	1	0	0	0	0	0	0	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	IDU	3	-	-	-	-	-	3	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	OR	3	-	3	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SE	2	0	0	0	0	1	0	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SG	10,872	160	2,834	852	1,543	4,827	653	3	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SO	484	11	132	37	64	213	28	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	UT	4	-	-	-	-	4	-	-	-



**Amortization Expense (Actuals)**

Sum of Range: 07/2020 - 06/2021

Allocation Method - Factor 2020 Protocol

(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WA	3	-	-	3	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WYP	49	-	-	-	49	-	-	-	-
4040000	AMOR LTD TRM PLNT	3035320	HYDRO PLANT INTANGIBLES	SG	148	2	38	12	21	66	9	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	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	312	5	81	24	44	138	19	0	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	0	0	-	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	294	-	294	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	247	5	67	19	32	109	14	0	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	1	-	-	-	-	1	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	93	-	-	93	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	53	-	-	-	53	-	-	-	-
<b>4040000 Total</b>					<b>48,540</b>	<b>931</b>	<b>13,623</b>	<b>3,693</b>	<b>5,876</b>	<b>21,769</b>	<b>2,638</b>	<b>9</b>	<b>-</b>
4049000	AMR LTD TRM PLNT-OT	566201	Amort Exp - Hydro - UT Klamath Adj	OTHER	4,233	-	-	-	-	-	-	-	4,233
4049000	AMR LTD TRM PLNT-OT	566970	AMORTIZATION JO BILL CREDIT	SG	(284)	(4)	(74)	(22)	(40)	(126)	(17)	(0)	-
<b>4049000 Total</b>					<b>3,949</b>	<b>(4)</b>	<b>(74)</b>	<b>(22)</b>	<b>(40)</b>	<b>(126)</b>	<b>(17)</b>	<b>(0)</b>	<b>4,233</b>
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	SG	6,496	95	1,694	509	922	2,884	390	2	-
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	UT	302	-	-	-	-	302	-	-	-
<b>4061000 Total</b>					<b>6,798</b>	<b>95</b>	<b>1,694</b>	<b>509</b>	<b>922</b>	<b>3,186</b>	<b>390</b>	<b>2</b>	<b>-</b>
4073000	REGULATORY DEBITS	566940	AMORT OF REG ASSETS - DEBITS	SG	24	0	6	2	3	11	1	0	-
4073000	REGULATORY DEBITS	566983	Amortz Reg A-Unrcvrd Plt/Decom Csts-OR	OR	1,057	-	1,057	-	-	-	-	-	-
4073000	REGULATORY DEBITS	566984	Amortz Reg A-Unrcvrd Plt/Decom Csts-UT	UT	1,332	-	-	-	-	1,332	-	-	-
4073000	REGULATORY DEBITS	586902	Preferred Stock Repurchase Loss Amort	OTHER	124	-	-	-	-	-	-	-	124
<b>4073000 Total</b>					<b>2,538</b>	<b>0</b>	<b>1,064</b>	<b>2</b>	<b>3</b>	<b>1,343</b>	<b>1</b>	<b>0</b>	<b>124</b>
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	IDU	5,176	-	-	-	-	-	5,176	-	-
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	OR	41,529	-	41,529	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	WA	11,930	-	-	11,930	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	IDU	315	-	-	-	-	-	315	-	-
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	OR	922	-	922	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	WA	546	-	-	546	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	IDU	31	-	-	-	-	-	31	-	-
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	OR	2	-	2	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	WA	14	-	-	14	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	IDU	1,751	-	-	-	-	-	1,751	-	-
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	OR	840	-	840	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	WA	660	-	-	660	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301601	BPA Reg Bill Bal Acct - St/Hwy Lighting	OR	0	-	0	-	-	-	-	-	-
<b>4074100 Total</b>					<b>63,718</b>	<b>-</b>	<b>43,294</b>	<b>13,151</b>	<b>-</b>	<b>-</b>	<b>7,274</b>	<b>-</b>	<b>-</b>
4074200	Reg Credits-BPA Exch	505201	Regional Bill Intchg Rec/Del-OR (PP)	OR	(43,294)	-	(43,294)	-	-	-	-	-	-
4074200	Reg Credits-BPA Exch	505202	Regional Bill Intchg Rec/Del-WA (PP)	WA	(13,151)	-	-	(13,151)	-	-	-	-	-
4074200	Reg Credits-BPA Exch	505204	Regional Bill Intchg Rec/Del-ID (RMP)	IDU	(7,274)	-	-	-	-	-	(7,274)	-	-
<b>4074200 Total</b>					<b>(63,718)</b>	<b>-</b>	<b>(43,294)</b>	<b>(13,151)</b>	<b>-</b>	<b>-</b>	<b>(7,274)</b>	<b>-</b>	<b>-</b>
<b>Grand Total</b>					<b>61,824</b>	<b>1,023</b>	<b>16,306</b>	<b>4,182</b>	<b>6,761</b>	<b>26,172</b>	<b>3,013</b>	<b>11</b>	<b>4,357</b>

# **B5. TAXES OTHER THAN INCOME**



Taxes Other Than Income (Actuals)  
 Sum of Range: 07/2020 - 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4081000	TAX OTH INC-U OP I	584960	Taxes Other Non-Income - Credit	SO	(459)	(10)	(125)	(35)	(60)	(202)	(27)	(0)	-
<b>4081000 Total</b>					<b>(459)</b>	<b>(10)</b>	<b>(125)</b>	<b>(35)</b>	<b>(60)</b>	<b>(202)</b>	<b>(27)</b>	<b>(0)</b>	<b>-</b>
4081500	PROPERTY TAXES	579000	PROPERTY TAX	GPS	161,965	3,571	44,011	12,434	21,293	71,160	9,462	33	-
4081500	PROPERTY TAXES	579012	Property Tax Exp - Reg Deferral/Amortz	OR	(299)	-	(299)	-	-	-	-	-	-
<b>4081500 Total</b>					<b>161,666</b>	<b>3,571</b>	<b>43,712</b>	<b>12,434</b>	<b>21,293</b>	<b>71,160</b>	<b>9,462</b>	<b>33</b>	<b>-</b>
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	CA	1,223	1,223	-	-	-	-	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	OR	29,492	-	29,492	-	-	-	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	UT	8	-	-	-	-	8	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	WYP	1,864	-	-	-	1,864	-	-	-	-
<b>4081800 Total</b>					<b>32,587</b>	<b>1,223</b>	<b>29,492</b>	<b>-</b>	<b>1,864</b>	<b>8</b>	<b>-</b>	<b>-</b>	<b>-</b>
4081990	MISC TAXES - OTHER	583260	PUBLIC UTILITY TAX	SO	13,664	301	3,713	1,049	1,796	6,003	798	3	-
4081990	MISC TAXES - OTHER	583261	OREGON ENERGY RESOURCE SUPPLIER TAX	OR	1,499	-	1,499	-	-	-	-	-	-
4081990	MISC TAXES - OTHER	583263	MONTANA ENERGY TAX	SE	212	3	53	16	33	94	14	0	-
4081990	MISC TAXES - OTHER	583265	WASHINGTON GROSS REVENUE TAX - SERVICES	WA	21	-	-	21	-	-	-	-	-
4081990	MISC TAXES - OTHER	583266	IDAHO KILOWATT HOUR TAX	SE	48	1	12	4	7	21	3	0	-
4081990	MISC TAXES - OTHER	583267	WYOMING ANNUAL CORPORATION FEE (TAX)	WYP	92	-	-	-	92	-	-	-	-
4081990	MISC TAXES - OTHER	583269	MONTANA WHOLESALE ENERGY TAX	SE	153	2	38	11	24	68	10	0	-
4081990	MISC TAXES - OTHER	583273	Wyoming Wind Generation Tax	SG	2,232	33	582	175	317	991	134	1	-
4081990	MISC TAXES - OTHER	583274	Nevada Commerce Tax	SO	21	0	6	2	3	9	1	0	-
4081990	MISC TAXES - OTHER	584100	GOVERNMENT ROYALTIES	SE	459	6	115	34	71	203	29	0	-
<b>4081990 Total</b>					<b>18,402</b>	<b>347</b>	<b>6,018</b>	<b>1,311</b>	<b>2,343</b>	<b>7,389</b>	<b>990</b>	<b>4</b>	<b>-</b>
<b>Grand Total</b>					<b>212,197</b>	<b>5,132</b>	<b>79,098</b>	<b>13,710</b>	<b>25,439</b>	<b>78,356</b>	<b>10,425</b>	<b>37</b>	<b>-</b>



# **B6. FEDERAL INCOME TAXES**



**Interest Expense & Renewable Energy Tax Credits**

Twelve Months Ended - June 2021

Allocation Method - Factor 2020 Protocol

(Allocated in Thousands)

Primary Account		Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4091000	INC TX UTIL OP INC	310310	Renewable Electricity Production Tax Cre	SG	(125,907)	(1,847)	(32,824)	(9,870)	(17,870)	(55,896)	(7,562)	(37)	-
4091000	INC TX UTIL OP INC	310313	Mining Rescue Training Credit - PMI	SE	(23)	(0)	(6)	(2)	(3)	(10)	(1)	(0)	-
4091000	INC TX UTIL OP INC	600600	Fuel Tax Credit	SE	(23)	(0)	(6)	(2)	(3)	(10)	(1)	(0)	-
4091000	INC TX UTIL OP INC	900900	Foreign Tax Credit	SO	(2)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	-
<b>4091000 Total</b>					<b>(125,954)</b>	<b>(1,848)</b>	<b>(32,836)</b>	<b>(9,873)</b>	<b>(17,878)</b>	<b>(55,917)</b>	<b>(7,565)</b>	<b>(37)</b>	<b>-</b>
4191000	AFUDC - OTHER	0	AFUDC - EQUITY	SNP	(79,166)	(1,649)	(20,265)	(5,904)	(10,408)	(36,227)	(4,687)	(17)	(8)
<b>4191000 Total</b>					<b>(79,166)</b>	<b>(1,649)</b>	<b>(20,265)</b>	<b>(5,904)</b>	<b>(10,408)</b>	<b>(36,227)</b>	<b>(4,687)</b>	<b>(17)</b>	<b>(8)</b>
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	OR	511	-	511	-	-	-	-	-	-
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	SO	(2,245)	(49)	(610)	(172)	(295)	(986)	(131)	(0)	-
<b>4211000 Total</b>					<b>(1,734)</b>	<b>(49)</b>	<b>(99)</b>	<b>(172)</b>	<b>(295)</b>	<b>(986)</b>	<b>(131)</b>	<b>(0)</b>	<b>-</b>
4211900	ASST SLS PRCDs-CLEAR	364105	ASSET SALES PROCEEDS - CLEARING	OTHER	0	-	-	-	-	-	-	-	0
<b>4211900 Total</b>					<b>0</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>0</b>
4270000	INT ON LNG-TRM DBT	585001	INTEREST EXPENSE - LONG-TERM DEBT - FMBS	SNP	369,073	7,688	94,477	27,523	48,525	168,890	21,853	78	39
4270000	INT ON LNG-TRM DBT	585002	INTEREST EXPENSE - LONG-TERM DEBT - MTNS	SNP	31,567	658	8,081	2,354	4,150	14,445	1,869	7	3
4270000	INT ON LNG-TRM DBT	585004	INTEREST EXPENSE - LT DEBT - PCRBS VARIA	SNP	314	7	80	23	41	143	19	0	0
4270000	INT ON LNG-TRM DBT	585005	INTEREST EXPENSE - LT DEBT - PCRB FEES &	SNP	774	16	198	58	102	354	46	0	0
<b>4270000 Total</b>					<b>401,728</b>	<b>8,369</b>	<b>102,837</b>	<b>29,959</b>	<b>52,818</b>	<b>183,833</b>	<b>23,787</b>	<b>84</b>	<b>43</b>
4280000	AMT DBT DISC & EXP	586160	AMORTIZATION - DEBT DISCOUNT	SNP	1,122	23	287	84	148	514	66	0	0
4280000	AMT DBT DISC & EXP	586170	AMORTIZATION - DEBT ISSUANCE EXP	SNP	3,398	71	870	253	447	1,555	201	1	0
<b>4280000 Total</b>					<b>4,521</b>	<b>94</b>	<b>1,157</b>	<b>337</b>	<b>594</b>	<b>2,069</b>	<b>268</b>	<b>1</b>	<b>0</b>
4281000	AMORTZN OF LOSS	586190	AMORTIZATION - LOSS ON REACQUIRED DEBT	SNP	582	12	149	43	77	267	34	0	0
<b>4281000 Total</b>					<b>582</b>	<b>12</b>	<b>149</b>	<b>43</b>	<b>77</b>	<b>267</b>	<b>34</b>	<b>0</b>	<b>0</b>
4290000	AMT PREM ON DEBT	586180	AMORTIZATION - DEBT PREMIUM/GAIN	SNP	(11)	(0)	(3)	(1)	(1)	(5)	(1)	(0)	(0)
<b>4290000 Total</b>					<b>(11)</b>	<b>(0)</b>	<b>(3)</b>	<b>(1)</b>	<b>(1)</b>	<b>(5)</b>	<b>(1)</b>	<b>(0)</b>	<b>(0)</b>
4310000	OTHER INTEREST EXP	0	4310000/0	SNP	8,804	183	2,254	657	1,158	4,029	521	2	1
4310000	OTHER INTEREST EXP	570019	Federal uncertain tax position int incom	SNP	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	(0)
4310000	OTHER INTEREST EXP	575039	State uncertain tax position int income	SNP	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
4310000	OTHER INTEREST EXP	575059	Current state tax interest income	SNP	(5)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	(0)
<b>4310000 Total</b>					<b>8,796</b>	<b>183</b>	<b>2,252</b>	<b>656</b>	<b>1,156</b>	<b>4,025</b>	<b>521</b>	<b>2</b>	<b>1</b>
4313000	INT EXP ON REG LIAB	0	INTEREST EXPENSE ON REG LIABILITIES	SNP	9,753	203	2,497	727	1,282	4,463	577	2	1
<b>4313000 Total</b>					<b>9,753</b>	<b>203</b>	<b>2,497</b>	<b>727</b>	<b>1,282</b>	<b>4,463</b>	<b>577</b>	<b>2</b>	<b>1</b>
4320000	AFUDC - BORROWED	585800	INTEREST CAPITALIZED (SEE OTH INCOME)	SNP	(44,281)	(922)	(11,335)	(3,302)	(5,822)	(20,263)	(2,622)	(9)	(5)
4320000	AFUDC - BORROWED	585860	INTEREST EXPENSE - AFUDC MANUAL ADJ	SNP	5,966	124	1,527	445	784	2,730	353	1	1
<b>4320000 Total</b>					<b>(38,315)</b>	<b>(798)</b>	<b>(9,808)</b>	<b>(2,857)</b>	<b>(5,038)</b>	<b>(17,533)</b>	<b>(2,269)</b>	<b>(8)</b>	<b>(4)</b>



Schedule M (Actuals)  
 Twelve Months Ending - June 2021  
 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	150	3	34	10	17	57	8	21
SCHMAP	130100	Non - Deductible Expenses	SO	1,980	44	538	152	260	870	116	0
SCHMAP	130400	PMINon Deductible Exp	SE	10	0	3	1	2	5	1	0
SCHMAP	130505	Executive Compensation 162(m)	SO	278	6	75	21	36	122	16	0
SCHMAP	130750	Non Deductible Fringe Benefits	SO	280	6	76	22	37	123	16	0
SCHMAP	130755	Non Deductible Parking Costs	SO	830	18	226	64	109	365	49	0
SCHMAP	505505	Income Tax Interest	SO	5	0	1	0	1	2	0	0
SCHMAP	610106	PMIFuel Tax Cr	SE	23	0	6	2	3	10	1	0
SCHMAP	610107	PMI Dividend Gross Up for Foreign Tax Cr	SO	2	0	0	0	0	1	0	0
SCHMAP	920145	PMI Mining Rescue Training Credit Addbac	SE	23	0	6	2	3	10	1	0
<b>SCHMAP Total</b>				<b>3,580</b>	<b>78</b>	<b>965</b>	<b>273</b>	<b>470</b>	<b>1,564</b>	<b>208</b>	<b>1</b>
SCHMAT	105100	Capitalized Labor Costs	SO	4,075	90	1,107	313	536	1,791	238	1
SCHMAT	105120	Book Depreciation	SCHMDEXP	859,860	15,265	194,739	57,336	100,259	326,400	43,466	169
SCHMAT	1051203	Book Depreciation- Utah DJ Plant Buy dow	UT	225,431	0	0	0	0	225,431	0	0
SCHMAT	1051204	Book Depreciation - Idaho Plant Buy Down	IDU	16,938	0	0	0	0	0	16,938	0
SCHMAT	1051204	Book Depreciation - Oregon Plant Buy Dow	OR	131,758	0	131,758	0	0	0	0	0
SCHMAT	105121	PMIBook Depreciation	SE	15,868	224	3,978	1,171	2,449	7,021	1,019	5
SCHMAT	105130	CIAC	CIAC	121,888	4,315	32,267	7,794	11,703	59,334	6,476	0
SCHMAT	105140	Highway relocation	SNPD	3,814	135	1,010	244	366	1,856	203	0
SCHMAT	105142	Avoided Costs	SNP	72,599	1,512	18,584	5,414	9,545	33,222	4,299	15
SCHMAT	105146	Capitalization of Test Energy	SG	2,663	39	694	209	378	1,182	160	1
SCHMAT	210200	Prepaid Taxes-property taxes	GPS	(4,930)	(109)	(1,340)	(378)	(648)	(2,166)	(288)	(1)
SCHMAT	220100	Bad Debts Allowance - Cash Basis	BADDEBT	3,554	73	1,723	523	26	1,018	192	0
SCHMAT	320270	Reg Asset FAS 158 Pension Liab Adj	SO	18,426	406	5,007	1,415	2,422	8,096	1,077	4
SCHMAT	320280	Reg Asset FAS 158 Post Retire Liab	SO	(521)	(11)	(141)	(40)	(68)	(229)	(30)	(0)
SCHMAT	320281	Reg Asset - Post-Retirement Settlement L	SO	3,703	82	1,006	284	487	1,627	216	1
SCHMAT	320282	Reg Asset - Post-Retirement Settlement L	UT	1,689	0	0	0	0	1,689	0	0
SCHMAT	415115	Reg Asset - UT STEP Pilot Programs Balan	OTHER	553	0	0	0	0	0	0	553
SCHMAT	415301	Environmental Costs WA	WA	231	0	0	231	0	0	0	0
SCHMAT	415424	Contra Reg Asset - Deer Creek Abandonmen	SE	18,094	256	4,536	1,335	2,793	8,006	1,162	6
SCHMAT	415426	Reg Asset - 2020 GRC - Meters Replaced b	OTHER	671	0	0	0	0	0	0	671
SCHMAT	415430	Reg Asset - CA - Transportation Electr	OTHER	(159)	0	0	0	0	0	0	(159)
SCHMAT	415510	WA Disallowed Colstrip #3 Write-off	WA	30	0	0	30	0	0	0	0
SCHMAT	415702	Reg Asset - Lake Side Liq.	WYP	27	0	0	0	27	0	0	0
SCHMAT	415703	Goodnoe Hills Liquidation Damages - WY	WYP	21	0	0	0	21	0	0	0
SCHMAT	415710	Reg Liability - WA - Accelerated Depreci	WA	(2,406)	0	0	(2,406)	0	0	0	0
SCHMAT	415723	Reg Asset - Cholla U4 - O&M Depreciation	IDU	806	0	0	0	0	806	0	0
SCHMAT	415728	Contra Reg Asset - Cholla U4 Closure - O	OR	620	0	620	0	0	0	0	0
SCHMAT	415729	Contra Reg Asset - Cholla U4 Closure - U	UT	1,556	0	0	0	0	1,556	0	0
SCHMAT	415730	Contra Reg Asset - Cholla U4 Closure - W	WYP	517	0	0	0	517	0	0	0
SCHMAT	415734	Reg Asset - Cholla Unrecovered Plant - C	CA	121	121	0	0	0	0	0	0
SCHMAT	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	(38)	0	0	0	0	0	0	(38)
SCHMAT	415841	Reg Asset - Emergency Service Programs -	OTHER	(5)	0	0	0	0	0	0	(5)
SCHMAT	415852	Powerdale Decommissioning Reg Asset - ID	IDU	12	0	0	0	0	0	12	0
SCHMAT	415855	CA - January 2010 Storm Costs	OTHER	(78)	0	0	0	0	0	0	(78)
SCHMAT	415857	ID - Deferred Overburden Costs	OTHER	36	0	0	0	0	0	0	36
SCHMAT	415858	WY - Deferred Overburden Costs	WYP	101	0	0	0	101	0	0	0
SCHMAT	415868	Reg Asset - UT - Solar Incentive Program	OTHER	(553)	0	0	0	0	0	0	(553)
SCHMAT	415876	Deferred Excess Net PowerCosts - OR	OTHER	1,405	0	0	0	0	0	0	1,405
SCHMAT	415883	Deferral of Renewable Energy Credit - WY	OTHER	131	0	0	0	0	0	0	131
SCHMAT	415926	Reg Liability - Depreciation Decrease -	OTHER	(564)	0	0	0	0	0	0	(564)
SCHMAT	415927	Reg Liability - Depreciation Decrease De	WA	7	0	0	7	0	0	0	0
SCHMAT	415939	Reg Asset - Carbon Plant Decommissioning	WYP	523	0	0	0	523	0	0	0
SCHMAT	415942	Reg Liability - Steam Decommissioning -	WA	1,785	0	0	1,785	0	0	0	0
SCHMAT	425105	Reg Asset - OR Asset Sale Gain Giveback	OTHER	(686)	0	0	0	0	0	0	(686)
SCHMAT	425360	Hermiston Swap	SG	172	3	45	13	24	76	10	0
SCHMAT	430100	Customer Service / Weatherization	OTHER	(196,674)	0	0	0	0	0	0	(196,674)
SCHMAT	505125	ACCRUED ROYALTIES	SE	3,253	46	816	240	502	1,440	209	1
SCHMAT	505400	Bonus Liability	SO	(643)	(14)	(175)	(49)	(85)	(282)	(38)	(0)
SCHMAT	505450	Accrued Payroll Taxes	SO	16,954	374	4,607	1,301	2,229	7,449	990	3
SCHMAT	5054501	Accrued Payroll Taxes - PMI	SE	13	0	3	1	2	6	1	0
SCHMAT	505520	Bonus Accrual - PMI	SE	65	1	16	5	10	29	4	0
SCHMAT	505600	Sick Leave Vacation & Personal Time	SO	72	2	20	6	10	32	4	0
SCHMAT	505601	Sick Leave Accrual - PMI	SE	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
SCHMAT	505700	Accrued Retention Bonus	SO	(8)	(0)	(2)	(1)	(1)	(3)	(0)	(0)



Schedule M (Actuals)  
 Twelve Months Ending - June 2021  
 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	605100	Trojan Decommissioning Costs	TROJD	(46)	(1)	(12)	(4)	(7)	(20)	(3)	(0)	
SCHMAT	605710	Reverse Accrued Final Reclamation	OTHER	(843)	0	0	0	0	0	0	(843)	
SCHMAT	605715	Trapper Mine Contract Obligation	SE	832	12	209	61	128	368	53	0	
SCHMAT	610000	Coal Mine Development-PMI	SE	(30)	(0)	(7)	(2)	(5)	(13)	(2)	(0)	
SCHMAT	610141	WA Rate Refunds	OTHER	1,850	0	0	0	0	0	0	1,850	
SCHMAT	610145	REG LIAB-DSM	OTHER	(2,786)	0	0	0	0	0	0	(2,786)	
SCHMAT	610150	REG LIABILITY - BRIDGER MINE ACCELERATED	OR	1,820	0	1,820	0	0	0	0	0	
SCHMAT	610155	Reg Liability - Plant Closure Cost - WA	WA	678	0	0	678	0	0	0	0	
SCHMAT	705241	Reg Liability - CA California Alternativ	OTHER	373	0	0	0	0	0	0	373	
SCHMAT	705245	REG LIABILITY - OR DIRECT ACCESS 5 YEAR	OTHER	747	0	0	0	0	0	0	747	
SCHMAT	705266	Reg Liability - Energy Savings Assistanc	OTHER	53	0	0	0	0	0	0	53	
SCHMAT	705267	Reg Liability - WA Decoupling Mechanism	OTHER	(13,025)	0	0	0	0	0	0	(13,025)	
SCHMAT	705336	Reg Liability - Sale of Renewable Energy	OTHER	801	0	0	0	0	0	0	801	
SCHMAT	705340	Reg Liability - Excess Income Tax Deferr	OTHER	(2,528)	0	0	0	0	0	0	(2,528)	
SCHMAT	705341	Reg Liability - Excess Income Tax Deferr	OTHER	(523)	0	0	0	0	0	0	(523)	
SCHMAT	705342	Reg Liability - Excess Income Tax Deferr	OTHER	(41,731)	0	0	0	0	0	0	(41,731)	
SCHMAT	705343	Reg Liability - Excess Income Tax Deferr	OTHER	(3,142)	0	0	0	0	0	0	(3,142)	
SCHMAT	705344	Reg Liability - Excess Income Tax Deferr	OTHER	35	0	0	0	0	0	0	35	
SCHMAT	705352	Reg Liability - CA Klamath River Dams Re	CA	265	265	0	0	0	0	0	0	
SCHMAT	705400	Reg Liability - OR Injuries & Damages Re	OR	1,485	0	1,485	0	0	0	0	0	
SCHMAT	705410	Reg Liability - Cholla Decommissioning -	CA	(30)	(30)	0	0	0	0	0	0	
SCHMAT	705411	Reg Liability - Cholla Decommissioning -	IDU	(113)	0	0	0	0	0	(113)	0	
SCHMAT	705412	Reg Liability - Cholla Decommissioning -	OR	8,685	0	8,685	0	0	0	0	0	
SCHMAT	705413	Reg Liability - Cholla Decommissioning -	UT	19,601	0	0	0	0	19,601	0	0	
SCHMAT	705414	Reg Liability - Cholla Decommissioning -	WYP	(280)	0	0	0	(280)	0	0	0	
SCHMAT	705420	Reg Liability - CA GHG Allowance Revenue	OTHER	1,091	0	0	0	0	0	0	1,091	
SCHMAT	705425	Reg Liability - Bridger Mine Accelerated	WA	1,275	0	0	1,275	0	0	0	0	
SCHMAT	705450	Reg Liability - Property Insurance Reser	CA	131	131	0	0	0	0	0	0	
SCHMAT	705451	Reg Liability - OR Property Insurance Re	OR	(7,968)	0	(7,968)	0	0	0	0	0	
SCHMAT	705452	Reg Liability - Property Insurance Reser	WA	114	0	0	114	0	0	0	0	
SCHMAT	705453	Reg Liability - ID Property Insurance Re	IDU	114	0	0	0	0	0	114	0	
SCHMAT	705455	Reg Liability - WY Property Insurance Re	WYP	(377)	0	0	0	(377)	0	0	0	
SCHMAT	705511	Regulatory Liability - CA Deferred Exces	OTHER	529	0	0	0	0	0	0	529	
SCHMAT	705515	Regulatory Liability - OR Deferred Exces	OTHER	(24,739)	0	0	0	0	0	0	(24,739)	
SCHMAT	705519	Regulatory Liability - WA Deferred Exces	OTHER	(3,572)	0	0	0	0	0	0	(3,572)	
SCHMAT	705521	Regulatory Liability - WY Deferred Exces	OTHER	(2,731)	0	0	0	0	0	0	(2,731)	
SCHMAT	705531	Regulatory Liability - UT Solar Feed-in	OTHER	(1,933)	0	0	0	0	0	0	(1,933)	
SCHMAT	715105	MCI FOG Wire Lease	SG	(1)	(0)	(0)	(0)	(0)	(0)	(0)	0	
SCHMAT	715720	NW Power Act-WA	OTHER	244	0	0	0	0	0	0	244	
SCHMAT	715810	Chehalis WA EFSEC C02 Mitigation Obligat	SG	(1)	(0)	(0)	(0)	(0)	(0)	(0)	0	
SCHMAT	720300	Pension / Retirement (Accrued / Prepaid)	SO	(29)	(1)	(8)	(2)	(4)	(13)	(2)	(0)	
SCHMAT	740100	Post Merger Loss-Reacquired Debt	SNP	582	12	149	43	77	267	34	0	
SCHMAT	910245	Contra Receivable from Joint Owners	SO	(744)	(16)	(202)	(57)	(98)	(327)	(43)	(0)	
SCHMAT	910905	Bridger Coal Company Underground Mine Co	SE	1,250	18	313	92	193	553	80	0	
SCHMAT	920110	PMI-WY Extraction Tax	SE	(303)	(4)	(76)	(22)	(47)	(134)	(19)	(0)	
<b>SCHMAT Total</b>				<b>1,257,858</b>	<b>23,193</b>	<b>405,264</b>	<b>78,957</b>	<b>133,710</b>	<b>704,859</b>	<b>77,225</b>	<b>206</b>	<b>(165,556)</b>
SCHMDP	1102051	TAX PERCENTAGE DEPLETION - DEDUCTION	SE	9	0	2	1	1	4	1	0	
SCHMDP	120100	Preferred Dividend - PPL	SNP	110	2	28	8	14	50	7	0	
SCHMDP	910900	PMI Depletion	SE	6,401	90	1,605	472	988	2,832	411	2	
<b>SCHMDP Total</b>				<b>6,520</b>	<b>93</b>	<b>1,635</b>	<b>481</b>	<b>1,004</b>	<b>2,887</b>	<b>418</b>	<b>2</b>	
SCHMDT	105122	Repair Deduction	SG	154,035	2,260	40,157	12,075	21,863	68,384	9,251	45	
SCHMDT	105125	Tax Depreciation	TAXDEPR	1,225,253	23,303	323,586	54,425	162,805	550,873	71,610	291	
SCHMDT	105126	PMI Tax Depreciation	SE	3,256	46	816	240	503	1,441	209	1	
SCHMDT	105137	Capitalized Depreciation	SO	7,807	172	2,121	599	1,026	3,430	456	2	
SCHMDT	1051411	AFUDC - DEBT	SNP	38,222	796	9,784	2,850	5,025	17,491	2,263	8	
SCHMDT	1051412	AFUDC - Equity	SNP	78,974	1,645	20,216	5,889	10,383	36,139	4,676	17	
SCHMDT	105143	Basis Intangible Difference	SNP	284	6	73	21	37	130	17	0	
SCHMDT	105152	Gain/(Loss) on Prop Dispositions	GPS	119,531	2,636	32,480	9,176	15,715	52,517	6,983	25	
SCHMDT	105153	Contract Liability Basis Adjustment -Che	SG	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
SCHMDT	105175	Removal Cost (net of salvage)	GPS	78,604	1,733	21,359	6,034	10,334	34,535	4,592	16	
SCHMDT	1052203	Cholla SHL-NOPA (Lease Amortization)	SG	2,076	30	541	163	295	922	125	1	
SCHMDT	105470	Book Gain/Loss on Land Sales	GPS	2,100	46	571	161	276	923	123	0	
SCHMDT	1102051	Tax Percentage Depletion - Deduction	SE	33	0	8	2	5	15	2	0	
SCHMDT	205025	PMI - Fuel Cost Adjustment	SE	(5,845)	(83)	(1,465)	(431)	(902)	(2,586)	(375)	(2)	
SCHMDT	205200	Coal M&S Inventory Write-Off	SNPD	1,063	38	281	68	102	517	56	0	



Schedule M (Actuals)  
 Twelve Months Ending - June 2021  
 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	205205	Inventory Reserve - PMI	(984)	(14)	(247)	(73)	(152)	(435)	(63)	(0)	0
SCHMDT	205411	PMISEC 263A Adjustment	775	11	194	57	120	343	50	0	0
SCHMDT	210100	Prepaid Taxes-OR PUC	498	0	498	0	0	0	0	0	0
SCHMDT	210120	Prepaid Taxes-UT PUC	713	0	0	0	0	713	0	0	0
SCHMDT	210130	Prepaid Taxes-ID PUC	(77)	0	0	0	0	0	(77)	0	0
SCHMDT	210170	Prepaid Lease-Gadsby Gas Turbine	(511)	(7)	(133)	(40)	(73)	(227)	(31)	(0)	0
SCHMDT	210175	Prepaid - FSA O&M - East	960	14	250	75	136	426	58	0	0
SCHMDT	210180	OTHER PREPAIDS	1,615	36	439	124	212	710	94	0	0
SCHMDT	210185	Prepaid Aircraft Maintenance Costs	(94)	(1)	(24)	(7)	(13)	(42)	(6)	(0)	0
SCHMDT	320279	Reg Liability - FAS 158 Post Retirement	(521)	(11)	(141)	(40)	(68)	(229)	(30)	(0)	0
SCHMDT	415110	Def Reg Asset-Transmission Srvc Deposit	31	0	8	2	4	14	2	0	0
SCHMDT	415200	REG ASSET - OR TRANSPORTATION ELECTRIC	2,188	0	0	0	0	0	0	0	2,188
SCHMDT	415260	Reg Asset - Fire Risk Mitigation - CA	11,210	0	0	0	0	0	0	0	11,210
SCHMDT	415300	Hazardous Waste Clean-up Costs	24,257	535	6,591	1,862	3,189	10,657	1,417	5	0
SCHMDT	415410	Reg Asset - Energy West Mining	3,264	46	818	241	504	1,444	210	1	0
SCHMDT	415411	ContraRA DeerCreekAband CA	(69)	(69)	0	0	0	0	0	0	0
SCHMDT	415412	ContraRA DeerCreekAband ID	(382)	0	0	0	0	0	(382)	0	0
SCHMDT	415413	ContraRA DeerCreekAband OR	248	0	248	0	0	0	0	0	0
SCHMDT	415414	ContraRA DeerCreekAband UT	1,483	0	0	0	0	1,483	0	0	0
SCHMDT	415415	ContraRA DeerCreekAband WA	797	0	0	797	0	0	0	0	0
SCHMDT	415416	ContraRA DeerCreekAband WY	171	0	0	0	171	0	0	0	0
SCHMDT	415417	Contra RA UMWA Pension CA	1,805	0	0	0	0	0	0	0	1,805
SCHMDT	415431	Reg Asset - WA Transportation Electric	210	0	0	0	0	0	0	0	210
SCHMDT	415520	Reg Asset - WA Decoupling Mechanism	4,033	0	0	0	0	0	0	0	4,033
SCHMDT	415531	Reg Asset - UT 2017 Protocol - MSP Defer	(13,200)	0	0	0	0	(13,200)	0	0	0
SCHMDT	415532	Reg Asset - WY 2017 Protocol - MSP Defer	(4,000)	0	0	0	(4,000)	0	0	0	0
SCHMDT	415545	Reg Asset - WA Merwin Project	3	0	0	0	0	0	0	0	3
SCHMDT	415655	CA GHG Allowance	(3,213)	0	0	0	0	0	0	0	(3,213)
SCHMDT	415675	Reg Asset - UT - Deferred Stock Redempti	(83)	0	0	0	0	0	0	0	(83)
SCHMDT	415676	Reg Asset - WY - Deferred Stock Redempti	(28)	0	0	0	0	0	0	0	(28)
SCHMDT	415677	Reg Asset - Pref Stock Redemp Loss WA	(13)	0	0	0	0	0	0	0	(13)
SCHMDT	415680	Deferred Intervenor Funding Grants-OR	568	0	0	0	0	0	0	0	568
SCHMDT	415701	CA Deferred Intervenor Funding	107	0	0	0	0	0	0	0	107
SCHMDT	415720	Reg Asset - Community Solar - OR	737	0	0	0	0	0	0	0	737
SCHMDT	415755	Reg Asset - Major Mtc Exp - Colstrip U4	259	0	0	259	0	0	0	0	0
SCHMDT	415815	Insurance Reserve	115,250	2,541	31,317	8,847	15,152	50,636	6,733	24	0
SCHMDT	415833	Reg Asset - Pension Settlement - CA	(26)	0	0	0	0	0	0	0	(26)
SCHMDT	415862	Reg Asset - CA Mobile Home Park Conversi	(7)	0	0	0	0	0	0	0	(7)
SCHMDT	415863	Reg Asset - UT Subscriber Solar Program	19	0	0	0	0	19	0	0	0
SCHMDT	415866	Reg Asset - OR Solar Feed-in Tariff	(126)	0	0	0	0	0	0	0	(126)
SCHMDT	415870	CA Def Excess NPC	(2,964)	0	0	0	0	0	0	0	(2,964)
SCHMDT	415874	Deferred Excess Net Power Costs - WY 08	(5,828)	0	0	0	0	0	0	0	(5,828)
SCHMDT	415875	Deferred Excess Net Power Costs - UT	17,506	0	0	0	0	0	0	0	17,506
SCHMDT	415878	REG ASSET - UT LIQUIDATED DAMAGES NAUGHT	(35)	0	0	0	0	(35)	0	0	0
SCHMDT	415879	Reg Asset - WY Liquidation Damages N2	(6)	0	0	0	(6)	0	0	0	0
SCHMDT	415882	Deferral of Renewable Energy Credit - WA	(166)	0	0	0	0	0	0	0	(166)
SCHMDT	415885	Reg Asset - Noncurrent Reclass - Other	596	0	0	0	0	0	0	0	596
SCHMDT	415892	Deferred Excess Net Power Costs - ID 09	(8,272)	0	0	0	0	0	0	0	(8,272)
SCHMDT	415920	Reg Asset - Depreciation Increase - ID	6,054	0	0	0	0	0	6,054	0	0
SCHMDT	415921	Reg Asset - Depreciation Increase - UT	(128)	0	0	0	0	(128)	0	0	0
SCHMDT	415922	Reg Asset - Depreciation Increase - WY	(442)	0	0	0	(442)	0	0	0	0
SCHMDT	415923	Reg Asset - Carbon Unrecovered Plant - I	(239)	0	0	0	0	0	(239)	0	0
SCHMDT	415924	Reg Asset - Carbon Unrecovered Plant - U	704	0	0	0	0	704	0	0	0
SCHMDT	415925	Reg Asset - Carbon Unrecovered Plant - W	(579)	0	0	0	(579)	0	0	0	0
SCHMDT	415929	Reg Asset - Carbon Decommissioning - CA	(346)	(346)	0	0	0	0	0	0	0
SCHMDT	415934	Reg Liability - Contra - Carbon Decommis	(17,302)	0	0	0	0	(17,302)	0	0	0
SCHMDT	415935	Reg Liability - Contra - Carbon Decommis	(223)	0	0	0	(223)	0	0	0	0
SCHMDT	415936	REG ASSET - CARBON PLANT DECOMMISSIONING	(1,607)	(24)	(419)	(126)	(228)	(713)	(97)	(0)	0
SCHMDT	415943	Reg Asset - Covid-19 Bill Assistance Pro	4,635	0	0	0	0	0	0	0	4,635
SCHMDT	415944	Reg Asset - Covid-19 Bill Assistance Pro	1,475	0	0	0	0	0	0	0	1,475
SCHMDT	425100	Deferred Regulatory Expense-IDU	36	0	0	0	0	0	36	0	0
SCHMDT	425215	Unearned Joint Use Pole Contact Revenue	(93)	(3)	(25)	(6)	(9)	(45)	(5)	0	0
SCHMDT	425400	UT Kalamath Relicensing Costs	(3,931)	0	0	0	0	0	0	0	(3,931)
SCHMDT	430110	Reg Asset balance reclass	(2,786)	0	0	0	0	0	0	0	(2,786)
SCHMDT	430112	Reg Asset - Other - Balance Reclass	4,728	0	0	0	0	0	0	0	4,728



Schedule M (Actuals)  
 Twelve Months Ending - June 2021  
 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	505510	Vacation Accrual - PMI	SE	(40)	(1)	(10)	(3)	(6)	(18)	(3)	(0)	0
SCHMDT	605103	ARO/Reg Diff - Trojan - WA	WA	(9)	0	0	(9)	0	0	0	0	0
SCHMDT	610100	PMIDEVT COST AMORT	SE	(676)	(10)	(169)	(50)	(104)	(299)	(43)	(0)	0
SCHMDT	6101001	AMORT NOPAS 99-00 RAR	SO	28	1	8	2	4	12	2	0	0
SCHMDT	610111	Bridger Coal Company Gain/Loss on Assets	SE	(37)	(1)	(9)	(3)	(6)	(16)	(2)	(0)	0
SCHMDT	610114	PMI EITF Pre Stripping Costs	SE	(893)	(13)	(224)	(66)	(138)	(395)	(57)	(0)	0
SCHMDT	610146	OR Reg Asset/Liability Consolidation	OR	11	0	11	0	0	0	0	0	0
SCHMDT	705261	Reg Liability - Sale of Renewable Energy	OTHER	(133)	0	0	0	0	0	0	0	(133)
SCHMDT	705265	Reg Liab - OR Energy Conservation Charge	OTHER	179	0	0	0	0	0	0	0	179
SCHMDT	705337	Reg Liability - Sale of Renewable Energy	OTHER	(634)	0	0	0	0	0	0	0	(634)
SCHMDT	705454	Reg Liability - UT Property Insurance Re	UT	6,131	0	0	0	0	6,131	0	0	0
SCHMDT	705755	Reg Liability - Non current Reclass - Ot	OTHER	(596)	0	0	0	0	0	0	0	(596)
SCHMDT	720200	Deferred Comp Plan Benefits-PPL	SO	(1,287)	(28)	(350)	(99)	(169)	(565)	(75)	(0)	0
SCHMDT	720500	Severance Accrual	SO	(2,802)	(62)	(762)	(215)	(368)	(1,231)	(164)	(1)	0
SCHMDT	720800	FAS 158 Pension Liability	SO	24,712	545	6,715	1,897	3,249	10,857	1,444	5	0
SCHMDT	720810	FAS 158 Post-Retirement Liability	SO	3,180	70	864	244	418	1,397	186	1	0
SCHMDT	720815	FAS 158 Post Retirement Liability	SO	(1,430)	(32)	(389)	(110)	(188)	(628)	(84)	(0)	0
SCHMDT	910530	Injuries and Damages Reserve	SO	(251,916)	(5,555)	(68,453)	(19,339)	(33,119)	(110,680)	(14,718)	(52)	0
<b>SCHMDT Total</b>				<b>1,617,837</b>	<b>30,252</b>	<b>427,137</b>	<b>85,497</b>	<b>210,734</b>	<b>704,087</b>	<b>100,198</b>	<b>385</b>	<b>21,187</b>
<b>Grand Total</b>				<b>2,885,795</b>	<b>53,616</b>	<b>835,001</b>	<b>165,209</b>	<b>345,917</b>	<b>1,413,397</b>	<b>178,050</b>	<b>594</b>	<b>(144,348)</b>

# **B7. D.I.T. EXPENSE AND I.T.C. ADJUSTMENT**



Deferred Income Tax Expense (Actuals)  
 Twelve Months Ending - June 2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4101000	105122	Repair Deduction	SG	37,872	556	9,873	2,969	5,375	16,813	2,275	11	-
4101000	105125	Tax Depreciation	TAXDEPR	301,248	5,729	79,559	13,381	40,028	135,441	17,607	71	-
4101000	105126	282DIT PMIDepreciation-Tax	SE	801	11	201	59	124	354	51	0	-
4101000	105137	Capitalized Depreciation	SO	1,920	42	522	147	252	843	112	0	-
4101000	105141	AFUDC Debt	SNP	9,398	196	2,406	701	1,236	4,300	556	2	1
4101000	1051411	AFUDC Equity	SNP	19,417	404	4,970	1,448	2,553	8,885	1,150	4	2
4101000	105143	282Basis Intangible Difference	SNP	70	1	18	5	9	32	4	0	0
4101000	105152	Gain / (Loss) on Prop. Disposition	GPS	29,389	648	7,986	2,256	3,864	12,912	1,717	6	-
4101000	105153	Contract Liability Basis Adjustment -Che	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
4101000	105175	Cost of Removal	GPS	19,326	426	5,251	1,484	2,541	8,491	1,129	4	-
4101000	1052203	Cholla SHL NOPA (Lease Amortization)	SG	510	7	133	40	72	227	31	0	-
4101000	105470	282Book Gain/Loss on Land Sales	GPS	516	11	140	40	68	227	30	0	-
4101000	110205	SRC Tax Percentage Depletion Deduct	SE	8	0	2	1	1	4	1	0	-
4101000	205025	PMI-Fuel Cost Adjustment	SE	(1,437)	(20)	(360)	(106)	(222)	(636)	(92)	(0)	-
4101000	205200	M&S INVENTORY WRITE-OFF	SNPD	261	9	69	17	25	127	14	-	-
4101000	205205	Inventory Reserve - PMI	SE	(242)	(3)	(61)	(18)	(37)	(107)	(16)	(0)	-
4101000	205411	190PMISec263A	SE	190	3	48	14	29	84	12	0	-
4101000	210100	283OR PUC Prepaid Taxes	OR	122	-	122	-	-	-	-	-	-
4101000	210120	283UT PUC Prepaid Taxes	UT	175	-	-	-	-	175	-	-	-
4101000	210130	283ID PUC Prepaid Taxes	IDU	(19)	-	-	-	-	-	(19)	-	-
4101000	210170	Prepaid - FSA O&M - West	SG	(126)	(2)	(33)	(10)	(18)	(56)	(8)	(0)	-
4101000	210175	Prepaid - FSA O&M - East	SG	236	3	62	19	34	105	14	0	-
4101000	210180	283Prepaid Membership Fees-EEI WSSC	SO	397	9	108	30	52	175	23	0	-
4101000	210185	Prepaid Aircraft Maintenance Costs	SG	(23)	(0)	(6)	(2)	(3)	(10)	(1)	(0)	-
4101000	210190	Prepaid Water Rights	SG	0	0	0	0	0	0	0	0	-
4101000	320279	Reg Liability - FAS 158 Post Retirement	SO	(128)	(3)	(35)	(10)	(17)	(56)	(7)	(0)	-
4101000	415110	190DEF REG ASSET-TRANSM SVC DEPOSIT	SG	8	0	2	1	1	3	0	0	-
4101000	415200	REG ASSET - OR TRANSPORTATION ELECTRIC	OTHER	538	-	-	-	-	-	-	-	538
4101000	415260	Reg Asset - Fire Risk Mitigation - CA	OTHER	2,756	-	-	-	-	-	-	-	2,756
4101000	415300	283Hazardous Waste/Environmental Cleanup	SO	5,964	132	1,621	458	784	2,620	348	1	-
4101000	415410	Reg Asset - Energy West Mining	SE	803	11	201	59	124	355	52	0	-
4101000	415411	ContraRA DeerCreekAband CA	CA	(17)	(17)	-	-	-	-	-	-	-
4101000	415412	ContraRA DeerCreekAband ID	IDU	(94)	-	-	-	-	-	(94)	-	-
4101000	415413	ContraRA DeerCreekAband OR	OR	61	-	61	-	-	-	-	-	-
4101000	415414	ContraRA DeerCreekAband UT	UT	365	-	-	-	-	365	-	-	-
4101000	415415	ContraRA DeerCreekAband WA	WA	196	-	-	196	-	-	-	-	-
4101000	415416	ContraRA DeerCreekAband WY	WYU	42	-	-	-	42	-	-	-	-
4101000	415417	Contra RA UMWA Pension CA	OTHER	444	-	-	-	-	-	-	-	444
4101000	415431	Reg Asset - WA Transportation Electric	OTHER	52	-	-	-	-	-	-	-	52
4101000	415520	Reg Asset - WA Decoupling Mechanism	OTHER	992	-	-	-	-	-	-	-	992
4101000	415531	Reg Asset - UT 2017 Protocol - MSP Defer	UT	(3,245)	-	-	-	-	(3,245)	-	-	-
4101000	415532	Reg Asset - WY 2017 Protocol - MSP Defer	WYP	(983)	-	-	-	(983)	-	-	-	-
4101000	415545	Reg Asset - WA Merwin Project	OTHER	1	-	-	-	-	-	-	-	1
4101000	415655	CA GHG Allowance	OTHER	(790)	-	-	-	-	-	-	-	(790)
4101000	415675	Reg Asset - UT - Deferred Stock Redempti	OTHER	(20)	-	-	-	-	-	-	-	(20)
4101000	415676	Reg Asset - WY - Deferred Stock Redempti	OTHER	(7)	-	-	-	-	-	-	-	(7)
4101000	415677	Reg Asset - Pref Stock Redemp Loss WA	OTHER	(3)	-	-	-	-	-	-	-	(3)
4101000	415680	190Def Intervenor Funding Grants-OR	OTHER	140	-	-	-	-	-	-	-	140
4101000	415701	CA Deferred Intervenor Funding	OTHER	26	-	-	-	-	-	-	-	26
4101000	415720	Reg Asset - Community Solar - OR	OTHER	181	-	-	-	-	-	-	-	181
4101000	415755	Reg Asset - Major Mtc Exp - Colstrip U4	WA	64	-	-	64	-	-	-	-	-





Deferred Income Tax Expense (Actuals)  
 Twelve Months Ending - June 2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4101000	415815	Insurance Reserve	SO	28,336	625	7,700	2,175	3,725	12,450	1,655	6	-
4101000	415833	Reg Asset - Pension Settlement - CA	OTHER	(6)	-	-	-	-	-	-	-	(6)
4101000	415862	Reg Asset - CA Mobile Home Park Conversi	OTHER	(2)	-	-	-	-	-	-	-	(2)
4101000	415863	Reg Asset - UT Subscriber Solar Program	UT	5	-	-	-	-	5	-	-	-
4101000	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	(31)	-	-	-	-	-	-	-	(31)
4101000	415870	Deferred Excess Net Power Costs CA	OTHER	(729)	-	-	-	-	-	-	-	(729)
4101000	415874	Deferred Excess Net Power Costs - WY 09	OTHER	(1,433)	-	-	-	-	-	-	-	(1,433)
4101000	415875	Deferred Excess Net Power Costs - UT	OTHER	4,304	-	-	-	-	-	-	-	4,304
4101000	415878	REG ASSET - UT LIQUIDATED DAMAGES NAUGHT	UT	(9)	-	-	-	-	(9)	-	-	-
4101000	415879	Reg Asset - WY Liquidation Damages N2	WYP	(1)	-	-	-	(1)	-	-	-	-
4101000	415882	Deferral of Renewable Energy Credit - WA	OTHER	(41)	-	-	-	-	-	-	-	(41)
4101000	415885	Reg Asset - Noncurrent Reclass - Other	OTHER	147	-	-	-	-	-	-	-	147
4101000	415892	Deferred Excess Net Power Costs - ID 09	OTHER	(2,034)	-	-	-	-	-	-	-	(2,034)
4101000	415920	Reg Asset - Depreciation Increase - ID	IDU	1,488	-	-	-	-	-	1,488	-	-
4101000	415921	Reg Asset - Depreciation Increase - UT	UT	(31)	-	-	-	-	(31)	-	-	-
4101000	415922	Reg Asset - Depreciation Increase - WY	WYP	(109)	-	-	-	(109)	-	-	-	-
4101000	415923	Reg Asset - Carbon Unrecovered Plant - I	IDU	(59)	-	-	-	-	-	(59)	-	-
4101000	415924	Reg Asset - Carbon Unrecovered Plant - U	UT	173	-	-	-	-	173	-	-	-
4101000	415925	Reg Asset - Carbon Unrecovered Plant - W	WYP	(142)	-	-	-	(142)	-	-	-	-
4101000	415929	Reg Asset - Carbon Decommissioning - CA	CA	(85)	(85)	-	-	-	-	-	-	-
4101000	415934	Reg Liability - Contra - Carbon Decommis	UT	(4,254)	-	-	-	-	(4,254)	-	-	-
4101000	415935	Reg Liability - Contra - Carbon Decommis	WYP	(55)	-	-	-	(55)	-	-	-	-
4101000	415936	REG ASSET - CARBON PLANT DECOMMISSIONING	SG	(395)	(6)	(103)	(31)	(56)	(175)	(24)	(0)	-
4101000	415943	Reg Asset - Covid-19 Bill Assistance Pro	OTHER	1,140	-	-	-	-	-	-	-	1,140
4101000	415944	Reg Asset - Covid-19 Bill Assistance Pro	OTHER	363	-	-	-	-	-	-	-	363
4101000	425100	190Deferred Regulatory Expense-IDU	IDU	9	-	-	-	-	-	9	-	-
4101000	425215	283Unearned Joint Use Pole Contact Revnu	SNPD	(23)	(1)	(6)	(1)	(2)	(11)	(1)	-	-
4101000	425400	UT Kalamath Relicensing Costs	OTHER	(966)	-	-	-	-	-	-	-	(966)
4101000	430110	Reg Asset Balance Reclass	OTHER	(685)	-	-	-	-	-	-	-	(685)
4101000	430112	Reg Asset - Other - Balance Reclass	OTHER	1,162	-	-	-	-	-	-	-	1,162
4101000	505510	190PMI Vacation/Bonus	SE	(10)	(0)	(2)	(1)	(2)	(4)	(1)	(0)	-
4101000	605103	ARO/Reg Diff - Trojan - WA	WA	(2)	-	-	(2)	-	-	-	-	-
4101000	610100	283PMI AMORT DEVELOPMENT	SE	(166)	(2)	(42)	(12)	(26)	(73)	(11)	(0)	-
4101000	6101001	190NOPA 103-99-00 RAR	SO	7	0	2	1	1	3	0	0	-
4101000	610111	283PMI SALE OF ASSETS	SE	(9)	(0)	(2)	(1)	(1)	(4)	(1)	(0)	-
4101000	610114	PMI EITF Pre stripping Cost	SE	(219)	(3)	(55)	(16)	(34)	(97)	(14)	(0)	-
4101000	610146	190OR Reg Asset/Liability Consol	OR	3	-	3	-	-	-	-	-	-
4101000	705261	Reg Liability - Sale of Renewable Energy	OTHER	(33)	-	-	-	-	-	-	-	(33)
4101000	705265	Reg Liab - OR Energy Conservation Charge	OTHER	44	-	-	-	-	-	-	-	44
4101000	705337	Reg Liability - Sale of Renewable Energy	OTHER	(156)	-	-	-	-	-	-	-	(156)
4101000	705454	Reg Liability - UT Property Insurance Re	UT	1,507	-	-	-	-	1,507	-	-	-
4101000	705755	Reg Liability - Non current Reclass - Ot	OTHER	(147)	-	-	-	-	-	-	-	(147)
4101000	720200	190Deferred Compensation Payout	SO	(316)	(7)	(86)	(24)	(42)	(139)	(18)	(0)	-
4101000	720500	190Severance	SO	(689)	(15)	(187)	(53)	(91)	(303)	(40)	(0)	-
4101000	720800	190FAS 158 Pension Liability	SO	6,076	134	1,651	466	799	2,669	355	1	-
4101000	720810	190FAS 158 Post Retirement Liability	SO	782	17	212	60	103	344	46	0	-
4101000	720815	FAS 158 Post Retirement Liability	SO	(352)	(8)	(96)	(27)	(46)	(154)	(21)	(0)	-
4101000	910530	190Injuries & Damages	SO	(61,938)	(1,366)	(16,830)	(4,755)	(8,143)	(27,213)	(3,619)	(13)	-
<b>4101000 Total</b>				<b>397,771</b>	<b>7,438</b>	<b>105,018</b>	<b>21,021</b>	<b>51,812</b>	<b>173,111</b>	<b>24,635</b>	<b>95</b>	<b>5,209</b>
4111000	100105	283FAS 109 Def Tax Liab WA-NUTIL	OTHER	1,595	-	-	-	-	-	-	-	1,595
4111000	105100	190CAPITALIZED LABOR COSTS	SO	(1,002)	(22)	(272)	(77)	(132)	(440)	(59)	(0)	-



Deferred Income Tax Expense (Actuals)  
 Twelve Months Ending - June 2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

FERC Account	FERC Secondary Acct	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other	
4111000	1051151	Depreciation Flow-Through - CA	CA	(328)	(328)	-	-	-	-	-	-	
4111000	1051152	Depreciation Flow-Through - FERC	FERC	(187)	-	-	-	-	-	(187)	-	
4111000	1051153	Depreciation Flow-Through - ID	IDU	(416)	-	-	-	-	(416)	-	-	
4111000	1051154	Depreciation Flow-Through - OR	OR	(1,937)	-	(1,937)	-	-	-	-	-	
4111000	1051155	Depreciation Flow-Through - OTHER	OTHER	(79)	-	-	-	-	-	-	(79)	
4111000	1051156	Depreciation Flow-Through - UT	UT	(4,820)	-	-	-	(4,820)	-	-	-	
4111000	1051157	Depreciation Flow-Through - WA	WA	1,147	-	-	1,147	-	-	-	-	
4111000	1051158	Depreciation Flow-Through - WYP	WYP	(1,137)	-	-	(1,137)	-	-	-	-	
4111000	1051159	Depreciation Flow-Through - WYU	WYU	(1,107)	-	-	(1,107)	-	-	-	-	
4111000	1051171	Protected PP&E EDIT - PMI - CA - Fed Onl	CA	(21)	(21)	-	-	-	-	-	-	
4111000	1051172	Protected PP&E EDIT - PMI - UFERC - Fed	FERC	(0)	-	-	-	-	-	(0)	-	
4111000	1051173	Protected PP&E EDIT - PMI - ID - Fed Onl	IDU	(89)	-	-	-	-	(89)	-	-	
4111000	1051174	Protected PP&E EDIT - PMI - OR - Fed Onl	OR	(344)	-	(344)	-	-	-	-	-	
4111000	1051175	Protected PP&E EDIT - PMI - UT - Fed Onl	UT	(588)	-	-	-	(588)	-	-	-	
4111000	1051176	Protected PP&E EDIT - PMI - WA - Fed Onl	WA	(315)	-	(315)	-	-	-	-	-	
4111000	1051177	Protected PP&E EDIT - PMI - WYP - Fed On	WYP	(232)	-	-	(232)	-	-	-	-	
4111000	105120	Book Depreciation	SCHMDEXP	(211,410)	(3,753)	(47,880)	(14,097)	(24,650)	(80,251)	(10,687)	(42)	(30,051)
4111000	1051201	Book Depreciation- Utah DJ Plant Buy dow	UT	(55,426)	-	-	-	(55,426)	-	-	-	
4111000	1051203	Book Depreciation - Idaho Plant Buy Down	IDU	(4,165)	-	-	-	-	(4,165)	-	-	
4111000	1051204	Book Depreciation - Oregon Plant Buy Dow	OR	(32,395)	-	(32,395)	-	-	-	-	-	
4111000	105121	282DIT PMIDepreciation-Book	SE	(3,901)	(55)	(978)	(288)	(602)	(1,726)	(251)	(1)	
4111000	105130	CIAC	CIAC	(29,968)	(1,061)	(7,933)	(1,916)	(2,877)	(14,588)	(1,592)	-	
4111000	105140	Highway Relocation	SNPD	(938)	(33)	(248)	(60)	(90)	(456)	(50)	-	
4111000	105142	Avoided Costs	SNP	(17,850)	(372)	(4,569)	(1,331)	(2,347)	(8,168)	(1,057)	(4)	(2)
4111000	105146	Capitalization of Test Energy	SG	(655)	(10)	(171)	(51)	(93)	(291)	(39)	(0)	
4111000	105220	282CHOLLA TAX LEASE	SG	(1,109)	(16)	(289)	(87)	(157)	(492)	(67)	(0)	
4111000	210200	283Prepaid Taxes-Property Taxes	GPS	1,212	27	329	93	159	533	71	0	
4111000	220100	190Bad Debt Allowance	BADDEBT	(874)	(18)	(424)	(129)	(6)	(250)	(47)	-	
4111000	320270	Reg Asset FAS 158 Pension Liab	SO	(4,530)	(100)	(1,231)	(348)	(596)	(1,990)	(265)	(1)	
4111000	320280	Reg Asset FAS 158 Post Retire Liab	SO	128	3	35	10	17	56	7	0	
4111000	320281	Reg Asset - Post-Retirement Settlement L	SO	(910)	(20)	(247)	(70)	(120)	(400)	(53)	(0)	
4111000	320282	Reg Asset - Post-Retirement Settlement L	UT	(415)	-	-	-	-	(415)	-	-	
4111000	415115	Reg Asset - UT STEP Pilot Programs Balan	OTHER	(136)	-	-	-	-	-	-	(136)	
4111000	415301	190Hazardous Waste/Environmental-WA	WA	(57)	-	-	(57)	-	-	-	-	
4111000	415424	Contra Reg Asset - Deer Creek Abandonmen	SE	(4,449)	(63)	(1,115)	(328)	(687)	(1,968)	(286)	(2)	
4111000	415426	Reg Asset - 2020 GRC - Meters Replaced b	OTHER	(165)	-	-	-	-	-	-	(165)	
4111000	415430	Reg Asset - CA - Transportation Electri	OTHER	39	-	-	-	-	-	-	39	
4111000	415510	283WA DISALLOWED COLSTRIP #3 WRITE-OFF	WA	(7)	-	-	(7)	-	-	-	-	
4111000	415645	RA - OR OCAT Expense Deferral	OTHER	302	-	-	-	-	-	-	302	
4111000	415702	REG ASSET - LAKE SIDE LIQ - WY	WYP	(7)	-	-	-	(7)	-	-	-	
4111000	415703	Goodnoe Hills Liquidation Damages - WY	WYP	(5)	-	-	-	(5)	-	-	-	
4111000	415710	Reg Liability - WA - Accelerated Depreci	WA	592	-	-	592	-	-	-	-	
4111000	415723	Reg Asset - Cholla U4 - O&M Depreciation	IDU	(198)	-	-	-	-	(198)	-	-	
4111000	415724	Deferred Income Tax Expense ~ Cholla U4	SG	0	0	0	0	0	0	0	0	
4111000	415728	Contra Reg Asset - Cholla U4 Closure - O	OR	(152)	-	(152)	-	-	-	-	-	
4111000	415729	Contra Reg Asset - Cholla U4 Closure - U	UT	(383)	-	-	-	(383)	-	-	-	
4111000	415730	Contra Reg Asset - Cholla U4 Closure - W	WYP	(127)	-	-	-	(127)	-	-	-	
4111000	415734	Reg Asset - Cholla Unrecovered Plant - C	CA	(30)	(30)	-	-	-	-	-	-	
4111000	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	9	-	-	-	-	-	-	9	
4111000	415841	Reg Asset - Emergency Service Programs -	OTHER	1	-	-	-	-	-	-	1	
4111000	415852	Powerdale Decommissioning Reg Asset - ID	IDU	(3)	-	-	-	-	(3)	-	-	



Deferred Income Tax Expense (Actuals)  
 Twelve Months Ending - June 2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4111000	415855	CA - January 2010 Storm Costs	OTHER	19	-	-	-	-	-	-	-	19
4111000	415857	ID - Deferred Overburden Costs	OTHER	(9)	-	-	-	-	-	-	-	(9)
4111000	415858	WY - Deferred Overburden Costs	WYP	(25)	-	-	-	(25)	-	-	-	-
4111000	415868	Reg Asset - UT - Solar Incentive Program	OTHER	136	-	-	-	-	-	-	-	136
4111000	415876	Deferred Excess Net PowerCosts - OR	OTHER	(346)	-	-	-	-	-	-	-	(346)
4111000	415883	Deferral of Renewable Energy Credit - WY	OTHER	(32)	-	-	-	-	-	-	-	(32)
4111000	415926	Reg Liability - Depreciation Decrease -	OTHER	139	-	-	-	-	-	-	-	139
4111000	415927	Reg Liability - Depreciation Decrease De	WA	(2)	-	-	(2)	-	-	-	-	-
4111000	415939	Reg Asset - Carbon Plant Decommissioning	WYP	(129)	-	-	-	(129)	-	-	-	-
4111000	415942	Reg Liability - Steam Decommissioning -	WA	(439)	-	-	(439)	-	-	-	-	-
4111000	425105	Reg Asset - OR Asset Sale Gain Giveback	OTHER	169	-	-	-	-	-	-	-	169
4111000	425360	190Hermiston Swap	SG	(42)	(1)	(11)	(3)	(6)	(19)	(3)	(0)	-
4111000	430100	283Weatherization	OTHER	48,355	-	-	-	-	-	-	-	48,355
4111000	505125	190Accrued Royalties	SE	(800)	(11)	(201)	(59)	(123)	(354)	(51)	(0)	-
4111000	505400	190Bonus Liability	SO	158	3	43	12	21	69	9	0	-
4111000	505450	Accrued Payroll Taxes	SO	(4,168)	(92)	(1,133)	(320)	(548)	(1,831)	(244)	(1)	-
4111000	5054501	Accrued Payroll Taxes - PMI	SE	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
4111000	505520	Bonus Accrual - PMI	SE	(16)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
4111000	505600	190Vacation Sickleave & PT Accrual	SO	(18)	(0)	(5)	(1)	(2)	(8)	(1)	(0)	-
4111000	505601	Sick Leave Accrual - PMI	SE	0	0	0	0	0	0	0	0	-
4111000	505700	190Accrued Retention Bonus	SO	2	0	1	0	0	1	0	0	-
4111000	605100	283TROJAN DECOMMISSIONING AMORT	TROJD	11	0	3	1	2	5	1	0	-
4111000	605710	REVERSE ACCRUED FINAL RECLAMATION	OTHER	207	-	-	-	-	-	-	-	207
4111000	605715	Trapper Mine Contract Obligation	SE	(205)	(3)	(51)	(15)	(32)	(91)	(13)	(0)	-
4111000	610000	283PMI Development Costs	SE	7	0	2	1	1	3	0	0	-
4111000	610141	190WA Rate Refunds	OTHER	(455)	-	-	-	-	-	-	-	(455)
4111000	610145	190REG LIAB_DSM	OTHER	685	-	-	-	-	-	-	-	685
4111000	610150	REG LIABILITY - BRIDGER MINE ACCELERATED	OR	(447)	-	(447)	-	-	-	-	-	-
4111000	610155	Reg Liability - Plant Closure Cost - WA	WA	(167)	-	-	(167)	-	-	-	-	-
4111000	705241	Reg Liability - CA California Alternativ	OTHER	(92)	-	-	-	-	-	-	-	(92)
4111000	705245	REG LIABILITY - OR DIRECT ACCESS 5 YEAR	OTHER	(184)	-	-	-	-	-	-	-	(184)
4111000	705266	Reg Liability - Energy Savings Assistanc	OTHER	(13)	-	-	-	-	-	-	-	(13)
4111000	705267	Reg Liability - WA Decoupling Mechanism	OTHER	3,202	-	-	-	-	-	-	-	3,202
4111000	705280	Non-Property EDIT - CA	CA	(268)	(268)	-	-	-	-	-	-	-
4111000	705281	Non-Property EDIT - ID	IDU	(134)	-	-	-	-	-	(134)	-	-
4111000	705284	Non-Property EDIT - WA	WA	(84)	-	-	(84)	-	-	-	-	-
4111000	705285	Non-Property EDIT - WY	WYU	(5,540)	-	-	-	(5,540)	-	-	-	-
4111000	705287	Protected PP&E EDIT - CA - Fed Only	CA	(1,348)	(1,348)	-	-	-	-	-	-	-
4111000	705288	Protected PP&E EDIT - ID - Fed Only	IDU	(4,615)	-	-	-	-	-	(4,615)	-	-
4111000	705289	Protected PP&E EDIT - OR - Fed Only	OR	(18,326)	-	(18,326)	-	-	-	-	-	-
4111000	705290	Protected PP&E EDIT - WA - Fed Only	WA	(4,861)	-	-	(4,861)	-	-	-	-	-
4111000	705291	Protected PP&E EDIT - WYP - Fed Only	WYP	(8,439)	-	-	-	(8,439)	-	-	-	-
4111000	705292	Protected PP&E EDIT - UT - Fed Only	UT	(30,602)	-	-	-	-	(30,602)	-	-	-
4111000	705294	Non-Protected PP&E EDIT - CA	CA	(1,015)	(1,015)	-	-	-	-	-	-	-
4111000	705295	Non-Protected PP&E EDIT - ID	IDU	(13,416)	-	-	-	-	-	(13,416)	-	-
4111000	705296	Non-Protected PP&E EDIT - WA	WA	(1,668)	-	-	(1,668)	-	-	-	-	-
4111000	705297	Non-Protected PP&E EDIT - WY Buydown - C	WYP	(6,757)	-	-	-	(6,757)	-	-	-	-
4111000	705298	Non-Protected PP&E EDIT - Utah Buydown -	UT	(17,996)	-	-	-	-	(17,996)	-	-	-
4111000	705336	Reg Liability - Sale of Renewable Energy	OTHER	(197)	-	-	-	-	-	-	-	(197)
4111000	705340	Reg Liability - Excess Income Tax Deferr	OTHER	622	-	-	-	-	-	-	-	622
4111000	705341	Reg Liability - Excess Income Tax Deferr	OTHER	129	-	-	-	-	-	-	-	129



Deferred Income Tax Expense (Actuals)  
 Twelve Months Ending - June 2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4111000	705342	Reg Liability - Excess Income Tax Deferr	OTHER	10,260	-	-	-	-	-	-	-	10,260
4111000	705343	Reg Liability - Excess Income Tax Deferr	OTHER	773	-	-	-	-	-	-	-	773
4111000	705344	Reg Liability - Excess Income Tax Deferr	OTHER	(9)	-	-	-	-	-	-	-	(9)
4111000	705346	Deferral of Protected PP&E ARAM - CA	CA	(482)	(482)	-	-	-	-	-	-	-
4111000	705347	Deferral of Protected PP&E ARAM - ID	IDU	1,552	-	-	-	-	-	1,552	-	-
4111000	705348	Deferral of Protected PP&E ARAM - OR	OR	(6,098)	-	(6,098)	-	-	-	-	-	-
4111000	705349	Deferral of Protected PP&E ARAM - UT	UT	(29,879)	-	-	-	-	(29,879)	-	-	-
4111000	705350	Deferral of Protected PP&E ARAM - WA	WA	1,364	-	-	1,364	-	-	-	-	-
4111000	705351	Deferral of Protected PP&E ARAM - WY	WYU	4,853	-	-	-	4,853	-	-	-	-
4111000	705352	Reg Liability - CA Klamath River Dams Re	CA	(65)	(65)	-	-	-	-	-	-	-
4111000	705400	Reg Liability - OR Injuries & Damages Re	OR	(365)	-	(365)	-	-	-	-	-	-
4111000	705410	Reg Liability - Cholla Decommissioning -	CA	7	7	-	-	-	-	-	-	-
4111000	705411	Reg Liability - Cholla Decommissioning -	IDU	28	-	-	-	-	-	28	-	-
4111000	705412	Reg Liability - Cholla Decommissioning -	OR	(2,135)	-	(2,135)	-	-	-	-	-	-
4111000	705413	Reg Liability - Cholla Decommissioning -	UT	(4,819)	-	-	-	-	(4,819)	-	-	-
4111000	705414	Reg Liability - Cholla Decommissioning -	WYP	69	-	-	-	69	-	-	-	-
4111000	705420	Reg Liability - CA GHG Allowance Revenue	OTHER	(268)	-	-	-	-	-	-	-	(268)
4111000	705425	Reg Liability - Bridger Mine Accelerated	WA	(313)	-	-	(313)	-	-	-	-	-
4111000	705450	Reg Liability - Property Insurance Reser	CA	(32)	(32)	-	-	-	-	-	-	-
4111000	705451	Reg Liability - OR Property Insurance Re	OR	1,959	-	1,959	-	-	-	-	-	-
4111000	705452	Reg Liability - Property Insurance Reser	WA	(28)	-	-	(28)	-	-	-	-	-
4111000	705453	Reg Liability - ID Property Insurance Re	IDU	(28)	-	-	-	-	-	(28)	-	-
4111000	705455	Reg Liability - WY Property Insurance Re	WYP	93	-	-	-	93	-	-	-	-
4111000	705511	Regulatory Liability - CA Deferred Exces	OTHER	(130)	-	-	-	-	-	-	-	(130)
4111000	705515	Regulatory Liability - OR Deferred Exces	OTHER	6,082	-	-	-	-	-	-	-	6,082
4111000	705519	Regulatory Liability - WA Deferred Exces	OTHER	878	-	-	-	-	-	-	-	878
4111000	705521	Regulatory Liability - WY Deferred Exces	OTHER	671	-	-	-	-	-	-	-	671
4111000	705531	Regulatory Liability - UT Solar Feed-in	OTHER	475	-	-	-	-	-	-	-	475
4111000	715105	MCI FOG Wire Lease	SG	0	0	0	0	0	0	0	0	-
4111000	715720	190NW Power Act(BPA Regional Crs)-WA	OTHER	(60)	-	-	-	-	-	-	-	(60)
4111000	715810	Chehalis WA EFSEC C02 Mitigation Obligat	SG	0	0	0	0	0	0	0	0	-
4111000	720300	190Pension/Retirement (Accrued/Prepaid)	SO	7	0	2	1	1	3	0	0	-
4111000	740100	283Post Merger Debt Loss	SNP	(143)	(3)	(37)	(11)	(19)	(66)	(8)	(0)	(0)
4111000	910245	Contra Receivable from Joint Owners	SO	183	4	50	14	24	80	11	0	-
4111000	910905	283PMI BCC Underground Mine Cost Deplet	SE	(307)	(4)	(77)	(23)	(47)	(136)	(20)	(0)	-
4111000	920110	190PMI WY Extraction Tax	SE	74	1	19	5	11	33	5	0	-
4111000	999998	Deferred Income Tax Expense ~ Solar ITC	SG	16	0	4	1	2	7	1	0	-
<b>4111000 Total</b>				<b>(462,672)</b>	<b>(9,179)</b>	<b>(126,631)</b>	<b>(23,916)</b>	<b>(51,389)</b>	<b>(257,671)</b>	<b>(36,169)</b>	<b>(239)</b>	<b>42,523</b>
<b>Grand Total</b>				<b>(64,901)</b>	<b>(1,741)</b>	<b>(21,613)</b>	<b>(2,896)</b>	<b>423</b>	<b>(84,560)</b>	<b>(11,534)</b>	<b>(144)</b>	<b>47,732</b>



**Investment Tax Credit Amortization (Actuals)**

Sum of Range: 07/2020 - 06/2021

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
4114000	DEF ITC-EL-FED-CR	0	DEF ITC CREDIT FED	DGU	(1,703)	-	-	-	(78)	(1,431)	(194)	(1)	-
<b>4114000 Total</b>					<b>(1,703)</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>(78)</b>	<b>(1,431)</b>	<b>(194)</b>	<b>(1)</b>	<b>-</b>
<b>Grand Total</b>					<b>(1,703)</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>(78)</b>	<b>(1,431)</b>	<b>(194)</b>	<b>(1)</b>	<b>-</b>

# **B8. PLANT IN SERVICE**



Electric Plant in Service (Actuals)  
 Year End: 06/2021  
 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	13,160	193	3,431	1,032	1,868	5,842	790	4	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG-P	177,567	2,605	46,292	13,919	25,203	78,831	10,664	52	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG-U	10,492	154	2,735	823	1,489	4,658	630	3	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	UT	(32,081)	-	-	-	-	(32,081)	-	-	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	OR	531	-	531	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	SG	50,482	741	13,161	3,957	7,165	22,411	3,032	15	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	UT	1,612	-	-	-	-	1,612	-	-	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	WYP	4,229	-	-	-	4,229	-	-	-	-
1010000	ELEC PLANT IN SERV	3031050	RCMS - REGION CONSTRUCTION MGMT SYSTEM	SO	11,249	248	3,057	864	1,479	4,942	657	2	-
1010000	ELEC PLANT IN SERV	3031080	FUEL MANAGEMENT SYSTEM	SO	3,293	73	895	253	433	1,447	192	1	-
1010000	ELEC PLANT IN SERV	3031230	AUTOMATE POLE CARD SYSTEM	SO	4,410	97	1,198	339	580	1,937	258	1	-
1010000	ELEC PLANT IN SERV	3031680	DISTRIBUTION AUTOMATION PILOT PROJECT	SO	13,886	306	3,773	1,066	1,826	6,101	811	3	-
1010000	ELEC PLANT IN SERV	3031830	CUSTOMER SERVICE SYSTEM (CSS)	CN	147,487	3,457	45,706	10,094	10,739	71,233	6,257	-	-
1010000	ELEC PLANT IN SERV	3032040	S A P	SO	182,742	4,030	49,657	14,028	24,025	80,288	10,676	38	-
1010000	ELEC PLANT IN SERV	3032130	PROD & TRANS PLANT	SG	2,705	40	705	212	384	1,201	162	1	-
1010000	ELEC PLANT IN SERV	3032140	MINING PLANT	SO	1,881	41	511	144	247	827	110	0	-
1010000	ELEC PLANT IN SERV	3032150	HYDRO PLANT	SO	5,048	111	1,372	387	664	2,218	295	1	-
1010000	ELEC PLANT IN SERV	3032220	ENTERPRISE DATA WRHSE - BI RPTG TOOL	SO	1,660	37	451	127	218	729	97	0	-
1010000	ELEC PLANT IN SERV	3032270	ENTERPRISE DATA WAREHOUSE	SO	5,877	130	1,597	451	773	2,582	343	1	-
1010000	ELEC PLANT IN SERV	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	2,908	64	790	223	382	1,278	170	1	-
1010000	ELEC PLANT IN SERV	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	2,020	45	549	155	266	888	118	0	-
1010000	ELEC PLANT IN SERV	3032360	2002 GRID NET POWER COST MODELING	SO	8,960	198	2,435	688	1,178	3,936	523	2	-
1010000	ELEC PLANT IN SERV	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	10,561	233	2,870	811	1,388	4,640	617	2	-
1010000	ELEC PLANT IN SERV	3032510	OPERATIONS MAPPING SYSTEM	SO	10,386	229	2,822	797	1,365	4,563	607	2	-
1010000	ELEC PLANT IN SERV	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	1,892	42	514	145	249	831	111	0	-
1010000	ELEC PLANT IN SERV	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	2,416	53	656	185	318	1,061	141	0	-
1010000	ELEC PLANT IN SERV	3032600	SINGLE PERSON SCHEDULING	SO	13,242	292	3,598	1,017	1,741	5,818	774	3	-
1010000	ELEC PLANT IN SERV	3032640	TIBCO SOFTWARE	SO	6,474	143	1,759	497	851	2,845	378	1	-
1010000	ELEC PLANT IN SERV	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	1,600	23	417	125	227	710	96	0	-
1010000	ELEC PLANT IN SERV	3032690	UTILITY INTERNATIONAL FORECASTING MODEL	SO	6,597	145	1,793	506	867	2,898	385	1	-
1010000	ELEC PLANT IN SERV	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	207	3	54	16	29	92	12	0	-
1010000	ELEC PLANT IN SERV	3032740	GADSBY INTANGIBLE ASSETS	SG	51	1	13	4	7	23	3	0	-
1010000	ELEC PLANT IN SERV	3032760	SWIFT 2 IMPROVEMENTS	SG	23,200	340	6,048	1,819	3,293	10,300	1,393	7	-
1010000	ELEC PLANT IN SERV	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	652	10	170	51	93	290	39	0	-
1010000	ELEC PLANT IN SERV	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	117	2	31	9	17	52	7	0	-
1010000	ELEC PLANT IN SERV	3032830	VCPRO - XEROX CUST STMT FRMTR ENHANCE -	SO	2,629	58	714	202	346	1,155	154	1	-
1010000	ELEC PLANT IN SERV	3032860	WEB SOFTWARE	SO	12,006	265	3,263	922	1,578	5,275	701	2	-
1010000	ELEC PLANT IN SERV	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	8,774	129	2,287	688	1,245	3,895	527	3	-
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	3032990	P8DM - FILENET P8	SO	7,015	155	1,906	538	922	3,082	410	1	-
1010000	ELEC PLANT IN SERV	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	88,742	1,302	23,135	6,956	12,595	39,397	5,330	26	-
1010000	ELEC PLANT IN SERV	3033170	GTX VERSION 7 SOFTWARE	CN	8,198	192	2,541	561	597	3,960	348	-	-
1010000	ELEC PLANT IN SERV	3033190	ITRON METER READING SOFTWARE	CN	5,868	138	1,819	402	427	2,834	249	-	-
1010000	ELEC PLANT IN SERV	3033210	ArcFM Software	SO	3,978	88	1,081	305	523	1,748	232	1	-
1010000	ELEC PLANT IN SERV	3033220	MONARCH EMS/SCADA	SO	29,411	649	7,992	2,258	3,867	12,922	1,718	6	-
1010000	ELEC PLANT IN SERV	3033240	IEE - Itron Enterprise Addition	CN	4,758	112	1,475	326	346	2,298	202	-	-
1010000	ELEC PLANT IN SERV	3033250	AMI Metering Software	CN	29,256	686	9,066	2,002	2,130	14,130	1,241	-	-
1010000	ELEC PLANT IN SERV	3033260	Big Data & Analytics	SO	3,698	82	1,005	284	486	1,625	216	1	-
1010000	ELEC PLANT IN SERV	3033270	CES - Customer Experience System	CN	9,590	225	2,972	656	698	4,632	407	-	-
1010000	ELEC PLANT IN SERV	3033280	MAPAPPS - Mapping Systems Application	SO	2,740	60	745	210	360	1,204	160	1	-
1010000	ELEC PLANT IN SERV	3033290	CUSTOMER CONTACTS	CN	3,872	91	1,200	265	282	1,870	164	-	-
1010000	ELEC PLANT IN SERV	3033300	SECID - CUST SECURE WEB LOGIN	CN	1,085	25	336	74	79	524	46	-	-
1010000	ELEC PLANT IN SERV	3033310	C&T - Energy Trading System	SO	21,326	470	5,795	1,637	2,804	9,370	1,246	4	-
1010000	ELEC PLANT IN SERV	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	10,106	148	2,635	792	1,434	4,486	607	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	3033370	DISTRIBUTION INTANGIBLES	WYP	158	-	-	-	158	-	-	-	-
1010000	ELEC PLANT IN SERV	3033380	MISCELLANEOUS SMALL SOFTWARE PACKAGES	SG	1,601	23	417	126	227	711	96	0	-
1010000	ELEC PLANT IN SERV	3033390	RMT TRADE SYSTEM	SO	923	20	251	71	121	406	54	0	-
1010000	ELEC PLANT IN SERV	M365		SO	3,700	82	1,005	284	486	1,626	216	1	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	CA	9	9	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	CN	3	0	1	0	0	1	0	-	-



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Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	IDU	15	-	-	-	-	15	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	OR	14	-	14	-	-	-	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	SE	9	0	2	1	4	1	0
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	SG	7,542	111	1,966	591	1,071	3,348	453
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	SO	47,842	1,055	13,000	3,673	6,290	21,020	2,795
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	UT	19	-	-	-	-	19	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	WA	16	-	-	16	-	-	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	WYP	243	-	-	-	243	-	-
1010000	ELEC PLANT IN SERV	3035320	HYDRO PLANT INTANGIBLES	SG	1,745	26	455	137	248	775	105
1010000	ELEC PLANT IN SERV	3035322	ACD-Call Center Automated Call Distribut	GN	4,132	97	1,281	283	301	1,996	175
1010000	ELEC PLANT IN SERV	3035330	OATI-OASIS INTERFACE	SO	1,240	27	337	95	163	545	72
1010000	ELEC PLANT IN SERV	3100000	LAND & LAND RIGHTS	SG	1,306	19	341	102	185	580	78
1010000	ELEC PLANT IN SERV	3101000	LAND OWNED IN FEE	SG	12,850	189	3,350	1,007	1,824	5,705	772
1010000	ELEC PLANT IN SERV	3102000	LAND RIGHTS	SG	41,789	613	10,895	3,276	5,931	18,552	2,510
1010000	ELEC PLANT IN SERV	3103000	WATER RIGHTS	SG	35,638	523	9,291	2,794	5,058	15,821	2,140
1010000	ELEC PLANT IN SERV	3108000	FEE LAND - LEASED	SG	37	1	10	3	5	16	2
1010000	ELEC PLANT IN SERV	3110000	STRUCTURES AND IMPROVEMENTS	SG	997,811	14,641	260,133	78,218	141,623	442,978	59,928
1010000	ELEC PLANT IN SERV	3120000	BOILER PLANT EQUIPMENT	SG	4,337,203	63,640	1,130,724	339,991	615,593	1,925,498	260,488
1010000	ELEC PLANT IN SERV	3140000	TURBOGENERATOR UNITS	SG	945,572	13,874	246,514	74,123	134,208	419,786	56,790
1010000	ELEC PLANT IN SERV	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	423,546	6,215	110,420	33,202	60,115	188,033	25,438
1010000	ELEC PLANT IN SERV	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	49	1	13	4	7	22	3
1010000	ELEC PLANT IN SERV	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	30,999	455	8,081	2,430	4,400	13,762	1,862
1010000	ELEC PLANT IN SERV	3300000	LAND AND LAND RIGHTS	SG-U	172	3	45	13	24	76	10
1010000	ELEC PLANT IN SERV	3301000	LAND OWNED IN FEE	SG-P	23,525	345	6,133	1,844	3,339	10,444	1,413
1010000	ELEC PLANT IN SERV	3301000	LAND OWNED IN FEE	SG-U	5,780	85	1,507	453	820	2,566	347
1010000	ELEC PLANT IN SERV	3302000	LAND RIGHTS	SG-P	8,035	118	2,095	630	1,140	3,567	483
1010000	ELEC PLANT IN SERV	3302000	LAND RIGHTS	SG-U	365	5	95	29	52	162	22
1010000	ELEC PLANT IN SERV	3303000	WATER RIGHTS	SG-P	21	0	5	2	3	9	1
1010000	ELEC PLANT IN SERV	3303000	WATER RIGHTS	SG-U	140	2	36	11	20	62	8
1010000	ELEC PLANT IN SERV	3304000	FLOOD RIGHTS	SG-P	407	6	106	32	58	181	24
1010000	ELEC PLANT IN SERV	3304000	FLOOD RIGHTS	SG-U	129	2	34	10	18	57	8
1010000	ELEC PLANT IN SERV	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	310	5	81	24	44	137	19
1010000	ELEC PLANT IN SERV	3310000	STRUCTURES AND IMPROVE	SG-P	202	3	53	16	29	90	12
1010000	ELEC PLANT IN SERV	3310000	STRUCTURES AND IMPROVE	SG-U	7,825	115	2,040	613	1,111	3,474	470
1010000	ELEC PLANT IN SERV	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	71,873	1,055	18,738	5,634	10,201	31,908	4,317
1010000	ELEC PLANT IN SERV	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	8,962	131	2,336	703	1,272	3,979	538
1010000	ELEC PLANT IN SERV	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	159,638	2,342	41,618	12,514	22,658	70,871	9,588
1010000	ELEC PLANT IN SERV	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	364	5	95	29	52	161	22
1010000	ELEC PLANT IN SERV	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	22,814	335	5,948	1,788	3,238	10,128	1,370
1010000	ELEC PLANT IN SERV	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	2,031	30	530	159	288	902	122
1010000	ELEC PLANT IN SERV	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	14,659	215	3,822	1,149	2,081	6,508	880
1010000	ELEC PLANT IN SERV	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	6,552	96	1,708	514	930	2,909	394
1010000	ELEC PLANT IN SERV	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	27,538	404	7,179	2,159	3,909	12,226	1,654
1010000	ELEC PLANT IN SERV	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	402,952	5,912	105,051	31,587	57,192	178,890	24,201
1010000	ELEC PLANT IN SERV	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	70,893	1,040	18,482	5,557	10,062	31,473	4,258
1010000	ELEC PLANT IN SERV	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF"	SG-P	23,797	349	6,204	1,865	3,378	10,565	1,429
1010000	ELEC PLANT IN SERV	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF"	SG-U	411	6	107	32	58	182	25
1010000	ELEC PLANT IN SERV	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	188	3	49	15	27	84	11
1010000	ELEC PLANT IN SERV	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	63	1	17	5	9	28	4
1010000	ELEC PLANT IN SERV	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	95,923	1,407	25,007	7,519	13,615	42,585	5,761
1010000	ELEC PLANT IN SERV	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	50,316	738	13,118	3,944	7,141	22,338	3,022
1010000	ELEC PLANT IN SERV	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	68,603	1,007	17,885	5,378	9,737	30,456	4,120
1010000	ELEC PLANT IN SERV	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	14,470	212	3,772	1,134	2,054	6,424	869
1010000	ELEC PLANT IN SERV	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	2,896	42	755	227	411	1,285	174
1010000	ELEC PLANT IN SERV	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	64	1	17	5	9	28	4
1010000	ELEC PLANT IN SERV	3350000	MISC POWER PLANT EQUIP	SG-U	172	3	45	14	24	76	10
1010000	ELEC PLANT IN SERV	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	2,392	35	624	187	339	1,062	144
1010000	ELEC PLANT IN SERV	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	23,207	341	6,050	1,819	3,294	10,303	1,394
1010000	ELEC PLANT IN SERV	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	3,068	45	800	240	435	1,362	184
1010000	ELEC PLANT IN SERV	3401000	LAND OWNED IN FEE	OR	75	-	75	-	-	-	-
1010000	ELEC PLANT IN SERV	3401000	LAND OWNED IN FEE	SG	12,648	186	3,297	991	1,795	5,615	760
1010000	ELEC PLANT IN SERV	3402000	LAND RIGHTS	SG	5,680	83	1,481	445	806	2,521	341
1010000	ELEC PLANT IN SERV	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	32,709	480	8,527	2,564	4,643	14,521	1,964
1010000	ELEC PLANT IN SERV	3410000	STRUCTURES & IMPROVEMENTS	SG	270,178	3,964	70,436	21,179	38,347	119,945	16,227
1010000	ELEC PLANT IN SERV	3410000	STRUCTURES & IMPROVEMENTS	UT	57	-	-	-	-	57	-
1010000	ELEC PLANT IN SERV	3420000	"FUEL HOLDERS, PRODUCERS, ACCES"	SG	16,383	240	4,271	1,284	2,325	7,273	984





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Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other		
1010000	ELEC PLANT IN SERV	3430000	PRIME MOVERS	SG	3,969,484	58,244	1,034,858	311,166	563,402	1,762,250	238,403	1,162	-
1010000	ELEC PLANT IN SERV	3440000	GENERATORS	SG	586,547	8,606	152,915	45,979	83,250	260,397	35,227	172	-
1010000	ELEC PLANT IN SERV	3440000	GENERATORS	UT	235	-	-	-	-	235	-	-	-
1010000	ELEC PLANT IN SERV	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	451,136	6,620	117,613	35,364	64,031	200,282	27,095	132	-
1010000	ELEC PLANT IN SERV	3450000	ACCESSORY ELECTRIC EQUIPMENT	UT	66	-	-	-	-	66	-	-	-
1010000	ELEC PLANT IN SERV	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	23,569	346	6,144	1,848	3,345	10,463	1,416	7	-
1010000	ELEC PLANT IN SERV	3500000	LAND AND LAND RIGHTS	SG	841	12	219	66	119	373	51	0	-
1010000	ELEC PLANT IN SERV	3501000	LAND OWNED IN FEE	SG	62,585	918	16,316	4,906	8,883	27,784	3,759	18	-
1010000	ELEC PLANT IN SERV	3502000	LAND RIGHTS	SG	246,449	3,616	64,250	19,319	34,979	109,411	14,801	72	-
1010000	ELEC PLANT IN SERV	3520000	STRUCTURES & IMPROVEMENTS	SG	313,031	4,593	81,608	24,538	44,430	138,970	18,800	92	-
1010000	ELEC PLANT IN SERV	3530000	STATION EQUIPMENT	SG	2,151,514	31,569	560,907	168,656	305,371	955,163	129,218	630	-
1010000	ELEC PLANT IN SERV	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	166,982	2,450	43,533	13,090	23,700	74,131	10,029	49	-
1010000	ELEC PLANT IN SERV	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	23,178	340	6,043	1,817	3,290	10,290	1,392	7	-
1010000	ELEC PLANT IN SERV	3540000	TOWERS AND FIXTURES	SG	1,333,441	19,566	347,633	104,528	189,260	591,980	80,085	390	-
1010000	ELEC PLANT IN SERV	3550000	POLES AND FIXTURES	SG	1,109,258	16,276	289,187	86,954	157,441	492,454	66,621	325	-
1010000	ELEC PLANT IN SERV	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	1,379,079	20,235	359,531	108,105	195,737	612,241	82,826	404	-
1010000	ELEC PLANT IN SERV	3570000	UNDERGROUND CONDUIT	SG	3,858	57	1,006	302	548	1,713	232	1	-
1010000	ELEC PLANT IN SERV	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	9,081	133	2,367	712	1,289	4,031	545	3	-
1010000	ELEC PLANT IN SERV	3590000	ROADS AND TRAILS	SG	12,146	178	3,167	952	1,724	5,392	729	4	-
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	729	729	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	IDU	502	-	-	-	-	-	502	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	OR	9,025	-	9,025	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	UT	25,902	-	-	-	-	25,902	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WA	1,401	-	-	1,401	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WYP	849	-	-	-	849	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WYU	48	-	-	-	48	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	CA	1,095	1,095	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	IDU	1,404	-	-	-	-	-	1,404	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	OR	5,274	-	5,274	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	UT	11,245	-	-	-	-	11,245	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WA	470	-	-	470	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WYP	4,189	-	-	-	4,189	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WYU	4,079	-	-	-	4,079	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	CA	5,252	5,252	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	IDU	3,369	-	-	-	-	-	3,369	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	OR	32,761	-	32,761	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	UT	60,222	-	-	-	-	60,222	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WA	7,172	-	-	7,172	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WYP	12,271	-	-	-	12,271	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WYU	4,812	-	-	-	4,812	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	CA	30,288	30,288	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	IDU	38,087	-	-	-	-	-	38,087	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	OR	258,066	-	258,066	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	UT	486,033	-	-	-	-	486,033	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WA	78,430	-	-	78,430	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WYP	118,961	-	-	-	118,961	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WYU	18,630	-	-	-	18,630	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	404	404	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	565	-	-	-	-	-	565	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	4,085	-	4,085	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	7,265	-	-	-	-	7,265	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	1,303	-	-	1,303	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	1,948	-	-	-	1,948	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	235	-	-	-	235	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	CA	82,752	82,752	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	IDU	100,391	-	-	-	-	-	100,391	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	OR	452,282	-	452,282	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	UT	432,296	-	-	-	-	432,296	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WA	119,245	-	-	119,245	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WYP	148,239	-	-	-	148,239	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WYU	29,577	-	-	-	29,577	-	-	-	-



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Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	37,857	37,857	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	43,081	-	-	-	-	43,081	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	299,985	-	299,985	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	267,391	-	-	-	267,391	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	84,380	-	-	84,380	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	111,474	-	-	-	111,474	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	14,642	-	-	-	14,642	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	CA	18,983	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	IDU	12,311	-	-	-	-	12,311	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	OR	106,676	-	106,676	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	UT	234,380	-	-	-	234,380	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WA	20,535	-	-	20,535	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WYP	27,977	-	-	-	27,977	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WYU	5,220	-	-	-	5,220	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	21,512	21,512	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	32,515	-	-	-	-	32,515	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	208,212	-	208,212	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	629,583	-	-	-	629,583	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	33,143	-	-	33,143	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	50,010	-	-	-	50,010	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	18,990	-	-	-	18,990	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	CA	57,639	57,639	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	IDU	88,427	-	-	-	-	88,427	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	OR	498,478	-	498,478	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	UT	605,316	-	-	-	605,316	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WA	123,083	-	-	123,083	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WYP	115,424	-	-	-	115,424	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WYU	16,168	-	-	-	16,168	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	CA	11,158	11,158	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	IDU	9,630	-	-	-	-	9,630	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	OR	106,497	-	106,497	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	UT	100,210	-	-	-	100,210	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WA	26,182	-	-	26,182	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WYP	19,161	-	-	-	19,161	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WYU	4,242	-	-	-	4,242	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	CA	17,453	17,453	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	IDU	38,675	-	-	-	-	38,675	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	OR	219,245	-	219,245	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	UT	280,355	-	-	-	280,355	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WA	46,974	-	-	46,974	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WYP	37,656	-	-	-	37,656	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WYU	12,931	-	-	-	12,931	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	CA	8,662	8,662	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	IDU	17,702	-	-	-	-	17,702	-
1010000	ELEC PLANT IN SERV	3700000	METERS	OR	97,716	-	97,716	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	UT	98,985	-	-	-	98,985	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	WA	14,451	-	-	14,451	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	WYP	14,454	-	-	-	14,454	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	WYU	2,703	-	-	-	2,703	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	CA	281	281	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	171	-	-	-	-	171	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	OR	2,666	-	2,666	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	UT	4,187	-	-	-	4,187	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WA	515	-	-	515	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	829	-	-	-	829	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	156	-	-	-	156	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	788	788	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	828	-	-	-	-	828	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	24,884	-	24,884	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	21,694	-	-	-	21,694	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	3,965	-	-	3,965	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	8,617	-	-	-	8,617	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	2,283	-	-	-	2,283	-	-
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	-	-



Electric Plant in Service (Actuals)  
 Year End: 06/2021  
 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	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	26	350	77	82	545	48	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	IDU	100	-	-	-	-	-	100	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	OR	5,887	-	5,887	-	-	-	-	-	-
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	166	2,042	577	988	3,302	439	2	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	UT	2,669	-	-	-	-	2,669	-	-	-
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	1,863	-	-	-	1,863	-	-	-	-
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	2	26	7	13	42	6	0	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	UT	84	-	-	-	-	84	-	-	-
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	3,819	3,819	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	CN	8,208	192	2,544	562	598	3,964	348	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	IDU	11,784	-	-	-	-	-	11,784	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	OR	35,384	-	35,384	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SE	888	13	223	66	137	393	57	0	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SG	12,084	177	3,150	947	1,715	5,365	726	4	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SO	99,576	2,196	27,058	7,644	13,091	43,749	5,817	20	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	UT	46,007	-	-	-	-	46,007	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WA	11,626	-	-	11,626	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WYP	11,620	-	-	-	11,620	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WYU	4,044	-	-	-	4,044	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	506	506	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	IDU	334	-	-	-	-	-	334	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	5,518	-	5,518	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	1,815	40	493	139	239	798	106	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	2,533	-	-	2,533	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	4,581	-	-	-	4,581	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	CA	110	110	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	CN	1,033	24	320	71	75	499	44	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	IDU	81	-	-	-	-	-	81	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	OR	1,494	-	1,494	-	-	-	-	-	-
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	1,632	24	426	128	232	725	98	0	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	SO	13,207	291	3,589	1,014	1,736	5,802	772	3	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	UT	868	-	-	-	-	868	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WA	58	-	-	58	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WYP	511	-	-	-	511	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WYU	42	-	-	-	42	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	36	36	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	2,995	70	928	205	218	1,447	127	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	426	-	-	-	-	-	426	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	908	-	908	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	28	0	7	2	4	12	2	0	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	2,446	36	638	192	347	1,086	147	1	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	47,440	1,046	12,891	3,642	6,237	20,843	2,772	10	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	722	-	-	-	-	722	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	333	-	-	333	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	1,715	-	-	-	1,715	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	76	-	-	-	76	-	-	-	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	CN	0	0	0	0	0	0	0	-	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	OR	3	-	3	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	SG	40	1	10	3	6	18	2	0	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	SO	121	3	33	9	16	53	7	0	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	UT	9	-	-	-	-	9	-	-	-
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	41	41	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	IDU	355	-	-	-	-	-	355	-	-



Electric Plant in Service (Actuals)  
 Year End: 06/2021  
 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	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	1,758	-	1,758	-	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SE	25	0	6	2	4	11	2
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	529	8	138	41	75	235	32
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	1,212	27	329	93	159	532	71
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	2,666	-	-	-	-	2,666	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	273	-	-	273	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	WYYP	615	-	-	-	615	-	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	OR	277	-	277	-	-	-	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	SO	308	7	84	24	40	135	18
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	UT	542	-	-	-	-	542	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	WA	43	-	-	43	-	-	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	WYYP	19	-	-	-	19	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	350	350	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	1,749	-	-	-	-	1,749	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	5,051	-	5,051	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	71	1	18	5	11	31	5
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	8,737	128	2,278	685	1,240	3,879	525
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	1,363	30	370	105	179	599	80
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	7,735	-	-	-	-	7,735	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	1,262	-	-	1,262	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYYP	2,179	-	-	-	2,179	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	383	-	-	-	383	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	1,569	1,569	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	4,607	-	-	-	-	4,607	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	13,309	-	13,309	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	181	3	45	13	28	80	12
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	7,477	110	1,949	586	1,061	3,320	449
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	350	8	95	27	46	154	20
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	20,975	-	-	-	-	20,975	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	3,060	-	-	3,060	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYYP	5,473	-	-	-	5,473	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	1,414	-	-	-	1,414	-	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	OR	269	-	269	-	-	-	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	SE	4	0	1	0	1	2	0
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	SG	3,746	55	977	294	532	1,663	225
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	UT	125	-	-	-	-	125	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	CA	507	507	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	IDU	1,785	-	-	-	-	1,785	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	OR	4,409	-	4,409	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SE	41	1	10	3	6	18	3
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SG	1,714	25	447	134	243	761	103
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SO	1,272	28	346	98	167	559	74
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	UT	8,997	-	-	-	-	8,997	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WA	962	-	-	962	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WYYP	3,699	-	-	-	3,699	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WYU	468	-	-	-	468	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	326	326	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	132	-	-	-	-	132	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	613	-	613	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SE	6	0	2	0	1	3	0
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	1,385	20	361	109	197	615	83
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	52	1	14	4	7	23	3
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	432	-	-	-	-	432	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	129	-	-	129	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYYP	390	-	-	-	390	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	81	-	-	-	81	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	317	-	317	-	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	457	7	119	36	65	203	27
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	215	5	58	16	28	94	13
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	1,589	-	-	-	-	1,589	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	170	-	-	170	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	WYYP	86	-	-	-	86	-	-
1010000	ELEC PLANT IN SERV	3923000	TRANSPORTATION EQUIPMENT	SO	2,993	66	813	230	394	1,315	175
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	CA	178	178	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	IDU	599	-	-	-	-	599	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	OR	2,736	-	2,736	-	-	-	-



Electric Plant in Service (Actuals)  
 Year End: 06/2021  
 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	3930000	STORES EQUIPMENT	SG	6,062	89	1,580	475	860	2,691	364	2	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	SO	249	5	68	19	33	109	15	0	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	UT	3,617	-	-	-	-	3,617	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WA	705	-	-	705	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WYP	1,252	-	-	-	1,252	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WYU	1	-	-	-	1	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	826	826	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	2,174	-	-	-	-	-	2,174	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	10,915	-	10,915	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	126	2	32	9	19	56	8	0	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	21,817	320	5,688	1,710	3,097	9,686	1,310	6	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	1,960	43	533	150	258	861	114	0	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	15,353	-	-	-	-	15,353	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	2,649	-	-	2,649	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	4,036	-	-	-	4,036	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	380	-	-	-	380	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	CA	496	496	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	IDU	1,348	-	-	-	-	-	1,348	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	OR	9,565	-	9,565	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SE	1,343	19	337	99	207	594	86	0	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SG	6,462	95	1,685	507	917	2,869	388	2	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SO	4,873	107	1,324	374	641	2,141	285	1	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	UT	7,829	-	-	-	-	7,829	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WA	1,458	-	-	1,458	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WYP	2,746	-	-	-	2,746	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WYU	98	-	-	-	98	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	CA	2,185	2,185	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	IDU	3,378	-	-	-	-	-	3,378	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	OR	14,203	-	14,203	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SG	388	6	101	30	55	172	23	0	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SO	3,234	71	879	248	425	1,421	189	1	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	UT	12,816	-	-	-	-	12,816	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WA	2,808	-	-	2,808	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYP	5,378	-	-	-	5,378	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYU	802	-	-	-	802	-	-	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	CA	74	74	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	561	-	-	-	-	-	561	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	892	-	892	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	124	2	32	10	18	55	7	0	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	798	-	-	-	-	798	-	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	210	-	-	-	210	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	1,848	1,848	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	4,498	-	-	-	-	-	4,498	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	13,885	-	13,885	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	1,231	18	321	97	175	547	74	0	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	1,566	35	426	120	206	688	91	0	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	16,554	-	-	-	-	16,554	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	2,992	-	-	2,992	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	6,930	-	-	-	6,930	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	1,041	-	-	-	1,041	-	-	-	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	OR	413	-	413	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	SG	3,025	44	789	237	429	1,343	182	1	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	UT	3	-	-	-	-	3	-	-	-
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	34,349	504	8,955	2,693	4,875	15,249	2,063	10	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	1,321	29	359	101	174	581	77	0	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	1,600	-	-	-	-	1,600	-	-	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	900	-	-	-	900	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	1,848	1,848	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	3,386	-	-	-	-	-	3,386	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	10,896	-	10,896	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	325	5	85	26	46	144	20	0	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	1,274	28	346	98	167	560	74	0	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	15,898	-	-	-	-	15,898	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	2,192	-	-	2,192	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	4,697	-	-	-	4,697	-	-	-	-



Electric Plant in Service (Actuals)  
 Year End: 06/2021  
 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	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	1,521	-	-	-	1,521	-	-	
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	CA	720	720	-	-	-	-	-	
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	IDU	2,062	-	-	-	-	2,062	-	
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	OR	3,346	-	3,346	-	-	-	-	
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SE	237	3	59	17	37	105	15	
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	6,906	101	1,800	541	980	3,066	415	
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	941	21	256	72	124	413	55	
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	UT	7,194	-	-	-	-	7,194	-	
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WA	1,622	-	-	1,622	-	-	-	
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYP	2,695	-	-	-	2,695	-	-	
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYU	898	-	-	-	898	-	-	
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	CA	6,324	6,324	-	-	-	-	-	
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	CN	3,849	90	1,193	263	280	1,859	163	
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	IDU	11,569	-	-	-	-	-	11,569	
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	OR	77,633	-	77,633	-	-	-	-	
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SE	280	4	70	21	43	124	18	
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SG	178,602	2,621	46,562	14,001	25,350	79,290	10,727	
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SO	93,553	2,063	25,421	7,182	12,299	41,103	5,466	
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	UT	58,270	-	-	-	-	58,270	-	
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	WA	12,221	-	-	12,221	-	-	-	
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	WYP	23,263	-	-	-	23,263	-	-	
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	WYU	5,938	-	-	-	5,938	-	-	
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	CA	300	300	-	-	-	-	-	
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	IDU	292	-	-	-	-	-	292	
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	OR	2,405	-	2,405	-	-	-	-	
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SE	82	1	21	6	13	36	5	
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SG	4,050	59	1,056	317	575	1,798	243	
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SO	487	11	132	37	64	214	28	
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	UT	1,657	-	-	-	-	1,657	-	
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	WA	477	-	-	477	-	-	-	
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	WYP	580	-	-	-	580	-	-	
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	WYU	101	-	-	-	101	-	-	
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	CA	52	52	-	-	-	-	-	
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	CN	82	2	26	6	6	40	4	
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	IDU	72	-	-	-	-	-	72	
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	OR	1,225	-	1,225	-	-	-	-	
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SE	4	0	1	0	1	2	0	
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SG	2,872	42	749	225	408	1,275	172	
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SO	2,229	49	606	171	293	979	130	
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	UT	1,382	-	-	-	-	1,382	-	
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WA	183	-	-	183	-	-	-	
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WYP	237	-	-	-	237	-	-	
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WYU	17	-	-	-	17	-	-	
1010000	ELEC PLANT IN SERV	3992100	LAND OWNED IN FEE	SE	1,823	26	457	134	281	807	117	
<b>1010000 Total</b>					<b>30,113,118</b>	<b>645,523</b>	<b>8,255,450</b>	<b>2,316,784</b>	<b>3,985,469</b>	<b>13,156,757</b>	<b>1,746,889</b>	<b>6,246</b>
1019000	ELEC PLT IN SERV-OTH	140109	Land-Non-Rec	SG	(297)	(4)	(77)	(23)	(42)	(132)	(18)	
1019000	ELEC PLT IN SERV-OTH	140129	ELECTRIC PLANT IN SERVICE - OTHER	SO	(1,246)	(27)	(339)	(96)	(164)	(548)	(73)	
1019000	ELEC PLT IN SERV-OTH	140139	PRODUCTION PLANT-NON-RECONCILED	SG	(19,189)	(282)	(5,003)	(1,504)	(2,723)	(8,519)	(1,152)	
1019000	ELEC PLT IN SERV-OTH	140149	TRANS PLANT NON-RECONCILED	SG	(5,037)	(74)	(1,313)	(395)	(715)	(2,236)	(303)	
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	CA	(381)	(381)	-	-	-	-	-	
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	IDU	(290)	-	-	-	-	-	(290)	
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	OR	(2,062)	-	(2,062)	-	-	-	-	
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	UT	(2,081)	-	-	-	-	(2,081)	-	
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	WA	(523)	-	-	(523)	-	-	-	
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	WYU	(758)	-	-	-	(758)	-	-	
<b>1019000 Total</b>					<b>(31,865)</b>	<b>(768)</b>	<b>(8,794)</b>	<b>(2,541)</b>	<b>(4,403)</b>	<b>(13,516)</b>	<b>(1,836)</b>	<b>(7)</b>
1020000	ELEC PL PUR OR SLD	0	ELECTRIC PLANT PURCHASED OR SOLD	SG	(553)	(8)	(144)	(43)	(79)	(246)	(33)	
1020000	ELEC PL PUR OR SLD	140708	CONTRA ELEC PLANT PURCH OR SOLD - LOSS	SG	553	8	144	43	79	246	33	
<b>1020000 Total</b>					<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	CA	4,945	4,945	-	-	-	-	-	
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	IDU	10,512	-	-	-	-	-	10,512	
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	OR	41,433	-	41,433	-	-	-	-	
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	UT	79,197	-	-	-	-	79,197	-	
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WA	10,662	-	-	10,662	-	-	-	
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WYU	21,091	-	-	-	21,091	-	-	
<b>1061000 Total</b>					<b>167,841</b>	<b>4,945</b>	<b>41,433</b>	<b>10,662</b>	<b>21,091</b>	<b>79,197</b>	<b>10,512</b>	



Electric Plant in Service (Actuals)  
 Year End: 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1062000	TRAN COMP CONST NOT	0									
<b>1062000 Total</b>				<b>929,896</b>	<b>13,644</b>	<b>242,427</b>	<b>72,894</b>	<b>131,983</b>	<b>412,827</b>	<b>55,849</b>	<b>272</b>
1063000	PROD COMP CONST NOT	0									
<b>1063000 Total</b>				<b>75,860</b>	<b>1,113</b>	<b>19,777</b>	<b>5,947</b>	<b>10,767</b>	<b>33,678</b>	<b>4,556</b>	<b>22</b>
1064000	GEN COMP CONST NOT	0									
<b>1064000 Total</b>				<b>62,878</b>	<b>1,387</b>	<b>17,086</b>	<b>4,827</b>	<b>8,267</b>	<b>27,626</b>	<b>3,673</b>	<b>13</b>
<b>Grand Total</b>				<b>31,317,729</b>	<b>665,844</b>	<b>8,567,379</b>	<b>2,408,573</b>	<b>4,153,174</b>	<b>13,696,568</b>	<b>1,819,644</b>	<b>6,546</b>

# **B9. CAPITAL LEASE PLANT**





**Capital Lease (Actuals)**

Year End: 06/2021

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	2,714	-	2,714	-	-	-	-
1011000	PRPTY UND CPTL LSS	3908220	(FINANCE LEASES-BLDGS)	SO	2,306	51	627	177	303	1,013	135
1011000	PRPTY UND CPTL LSS	3908230	(FINANCE LEASES-GAS)	SG	12,159	178	3,170	953	1,726	5,398	730
<b>1011000 Total</b>					<b>17,180</b>	<b>229</b>	<b>6,511</b>	<b>1,130</b>	<b>2,029</b>	<b>6,411</b>	<b>865</b>
1011500	CAP LEASES-ACCM AMRT	3908220	(FINANCE LEASES-BLDGS)	OR	(1,102)	-	(1,102)	-	-	-	-
1011500	CAP LEASES-ACCM AMRT	3908220	(FINANCE LEASES-BLDGS)	SO	(2,306)	(51)	(627)	(177)	(303)	(1,013)	(135)
1011500	CAP LEASES-ACCM AMRT	3908230	(FINANCE LEASES-GAS)	SG	(2,278)	(33)	(594)	(179)	(323)	(1,011)	(137)
<b>1011500 Total</b>					<b>(5,686)</b>	<b>(84)</b>	<b>(2,322)</b>	<b>(356)</b>	<b>(627)</b>	<b>(2,025)</b>	<b>(272)</b>
1011900	PRPTY UND CPTL LSS-O	142785	FINANCE LEASE ROU ASSETS (COST) - PPAS	UT	11,714	-	-	-	-	11,714	-
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	70	1,249	376	680	2,128	288
<b>1011900 Total</b>					<b>19,653</b>	<b>70</b>	<b>4,395</b>	<b>376</b>	<b>680</b>	<b>13,842</b>	<b>288</b>
1011950	CAP LEASES-ACCM AMRT	142885	Finance Lease ROU Assets (A/D) - PPAs	UT	(9,158)	-	-	-	-	(9,158)	-
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)	(70)	(1,249)	(376)	(680)	(2,128)	(288)
<b>1011950 Total</b>					<b>(17,097)</b>	<b>(70)</b>	<b>(4,395)</b>	<b>(376)</b>	<b>(680)</b>	<b>(11,286)</b>	<b>(288)</b>
<b>Grand Total</b>					<b>14,049</b>	<b>145</b>	<b>4,189</b>	<b>775</b>	<b>1,402</b>	<b>6,942</b>	<b>593</b>

# **B10.PLANT HELD FOR FUTURE USE**



**Plant Held for Future Use (Actuals)**

Year End: 06/2021

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	3401000	LAND OWNED IN FEE	SG	8,923	131	2,326	699	1,267	3,961	536	3	-
1050000	EL PLT HLD FTR USE	3501000	LAND OWNED IN FEE	SG	925	14	241	73	131	411	56	0	-
1050000	EL PLT HLD FTR USE	3502000	LAND RIGHTS	SG	755	11	197	59	107	335	45	0	-
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	CA	683	683	-	-	-	-	-	-	-
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	OR	3,912	-	3,912	-	-	-	-	-	-
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	UT	5,716	-	-	-	-	5,716	-	-	-
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	WYP	1	-	-	-	1	-	-	-	-
1050000	EL PLT HLD FTR USE	3891000	LAND OWNED IN FEE	OR	2,981	-	2,981	-	-	-	-	-	-
<b>1050000 Total</b>					<b>23,896</b>	<b>839</b>	<b>9,658</b>	<b>831</b>	<b>1,506</b>	<b>10,423</b>	<b>637</b>	<b>3</b>	<b>-</b>
<b>Grand Total</b>					<b>23,896</b>	<b>839</b>	<b>9,658</b>	<b>831</b>	<b>1,506</b>	<b>10,423</b>	<b>637</b>	<b>3</b>	<b>-</b>

# **B11. MISC. DEFERRED DEBITS**



Deferred Debits (Actuals)  
 Year End: 06/2021  
 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	33	588	173	362	1,038	151	1	-
1861000	MS DEF DB-OTH WIP	185017	ERCs - Impairment Reserve	SE	(2,040)	(29)	(511)	(151)	(315)	(903)	(131)	(1)	-
<b>1861000 Total</b>					<b>307</b>	<b>4</b>	<b>77</b>	<b>23</b>	<b>47</b>	<b>136</b>	<b>20</b>	<b>0</b>	<b>-</b>
1861200	FINANCING COSTS DEFR	185025	FINANCING COST DEFERRED	SO	1	0	0	0	0	1	0	0	-
1861200	FINANCING COSTS DEFR	185026	DEFERRED - S-3 SHELF REGISTRATION COSTS	SO	77	2	21	6	10	34	5	0	-
1861200	FINANCING COSTS DEFR	185027	UNAMORTIZED CREDIT AGREEMENT COSTS	OTHER	1,884	-	-	-	-	-	-	-	1,884
1861200	FINANCING COSTS DEFR	185029	UNAMORTIZED PCRB MADE CONVERSION COSTS	OTHER	256	-	-	-	-	-	-	-	256
1861200	FINANCING COSTS DEFR	185030	UNAMORTIZED '94 SERIES RESTRUCTURING COS	OTHER	196	-	-	-	-	-	-	-	196
<b>1861200 Total</b>					<b>2,414</b>	<b>2</b>	<b>21</b>	<b>6</b>	<b>10</b>	<b>34</b>	<b>5</b>	<b>0</b>	<b>2,335</b>
1865000	DEF COAL MINE COSTS	184414	DEFERRED COAL COSTS - WYODAK SETTLEMENT	SE	503	7	126	37	78	222	32	0	-
<b>1865000 Total</b>					<b>503</b>	<b>7</b>	<b>126</b>	<b>37</b>	<b>78</b>	<b>222</b>	<b>32</b>	<b>0</b>	<b>-</b>
1868000	MISC DF DR-OTH-CST	134305	Oth Def Chrg - IT Licenses/Maintenance	OTHER	108	-	-	-	-	-	-	-	108
1868000	MISC DF DR-OTH-CST	185313	MEAD-PHOENIX-AVAILABILITY & TRANS CHARGE	SG	3,887	57	1,013	305	552	1,726	233	1	-
1868000	MISC DF DR-OTH-CST	185335	LACOMB IRRIGATION	SG	27	0	7	2	4	12	2	0	-
1868000	MISC DF DR-OTH-CST	185336	BOGUS CREEK	SG	767	11	200	60	109	341	46	0	-
1868000	MISC DF DR-OTH-CST	185337	POINT-TO-POINT TRANS RESERVATIONS	SG	1,892	28	493	148	268	840	114	1	-
1868000	MISC DF DR-OTH-CST	185359	LT Lake Side 2 Maint. Prepayment	SG	21,225	311	5,533	1,664	3,013	9,423	1,275	6	-
1868000	MISC DF DR-OTH-CST	185360	LT LAKE SIDE MAINT PREPAYMENT	SG	11,807	173	3,078	926	1,676	5,242	709	3	-
1868000	MISC DF DR-OTH-CST	185361	LT CHEHALIS CSA MAINT. PREPAYMENT	SG	23,923	351	6,237	1,875	3,395	10,621	1,437	7	-
1868000	MISC DF DR-OTH-CST	185362	LT Currant Creek CSA Maint Prepayment	SG	23,241	341	6,059	1,822	3,299	10,318	1,396	7	-
1868000	MISC DF DR-OTH-CST	185371	LT Chehalis CSA Prepaid O&M	SG	1,114	16	291	87	158	495	67	0	-
1868000	MISC DF DR-OTH-CST	185551	LT Prepaid-FSA Capital - Dunlap	SG	1,525	22	397	120	216	677	92	0	-
1868000	MISC DF DR-OTH-CST	185552	LT Prepaid-FSA Capital - Ekola Flats	SG	125	2	32	10	18	55	7	0	-
1868000	MISC DF DR-OTH-CST	185557	LT Prepaid-FSA Capital - Glenrock I	SG	2,720	40	709	213	386	1,207	163	1	-
1868000	MISC DF DR-OTH-CST	185558	LT Prepaid-FSA Capital - Glenrock III	SG	1,071	16	279	84	152	476	64	0	-
1868000	MISC DF DR-OTH-CST	185561	LT Prepaid-FSA Capital - Goodnoe Hills	SG	1,920	28	501	151	273	852	115	1	-
1868000	MISC DF DR-OTH-CST	185564	LT Prepaid-FSA Capital - High Plains	SG	2,720	40	709	213	386	1,207	163	1	-
1868000	MISC DF DR-OTH-CST	185567	LT Prepaid-FSA Capital - Leaning Juniper	SG	2,761	41	720	216	392	1,226	166	1	-
1868000	MISC DF DR-OTH-CST	185570	LT Prepaid-FSA Capital - Marengo I	SG	2,243	33	585	176	318	996	135	1	-
1868000	MISC DF DR-OTH-CST	185571	LT Prepaid-FSA Capital - Marengo II	SG	1,111	16	290	87	158	493	67	0	-
1868000	MISC DF DR-OTH-CST	185574	LT Prepaid-FSA Capital - McFadden Ridge	SG	783	11	204	61	111	348	47	0	-
1868000	MISC DF DR-OTH-CST	185576	LT Prepaid-FSA Capital - Pryor Mtn	SG	33	0	9	3	5	15	2	0	-
1868000	MISC DF DR-OTH-CST	185577	LT Prepaid-FSA Capital - Rolling Hills	SG	2,720	40	709	213	386	1,207	163	1	-
1868000	MISC DF DR-OTH-CST	185580	LT Prepaid-FSA Capital - Seven Mile I	SG	2,720	40	709	213	386	1,207	163	1	-
1868000	MISC DF DR-OTH-CST	185581	LT Prepaid-FSA Capital - Seven Mile II	SG	536	8	140	42	76	238	32	0	-
<b>1868000 Total</b>					<b>110,978</b>	<b>1,627</b>	<b>28,904</b>	<b>8,691</b>	<b>15,736</b>	<b>49,221</b>	<b>6,659</b>	<b>32</b>	<b>108</b>
1869000	MISC DF DR-OTH-NC	185334	HERMISTON SWAP	SG	2,590	38	675	203	368	1,150	156	1	-
<b>1869000 Total</b>					<b>2,590</b>	<b>38</b>	<b>675</b>	<b>203</b>	<b>368</b>	<b>1,150</b>	<b>156</b>	<b>1</b>	<b>-</b>
<b>Grand Total</b>					<b>116,791</b>	<b>1,678</b>	<b>29,804</b>	<b>8,960</b>	<b>16,239</b>	<b>50,763</b>	<b>6,871</b>	<b>33</b>	<b>2,444</b>

# **B13. MATERIALS & SUPPLIES**



Material & Supplies (Actuals)  
 Year End: 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1511120	COAL INVNTY-HUNTER	0									
<b>1511120 Total</b>			<b>71,160</b>	<b>1,006</b>	<b>17,839</b>	<b>5,250</b>	<b>10,983</b>	<b>31,487</b>	<b>4,571</b>	<b>24</b>	<b>-</b>
1511130	COAL INVNTY-HTG	0									
<b>1511130 Total</b>			<b>23,857</b>	<b>337</b>	<b>5,980</b>	<b>1,760</b>	<b>3,682</b>	<b>10,556</b>	<b>1,533</b>	<b>8</b>	<b>-</b>
1511140	COAL INVNTY-JB	0									
<b>1511140 Total</b>			<b>34,164</b>	<b>483</b>	<b>8,564</b>	<b>2,521</b>	<b>5,273</b>	<b>15,117</b>	<b>2,195</b>	<b>12</b>	<b>-</b>
1511160	COAL INVNTY-NAU	0									
<b>1511160 Total</b>			<b>24,588</b>	<b>347</b>	<b>6,164</b>	<b>1,814</b>	<b>3,795</b>	<b>10,880</b>	<b>1,580</b>	<b>8</b>	<b>-</b>
1511300	COAL INVNTY-COLSTRI	0									
<b>1511300 Total</b>			<b>1,908</b>	<b>27</b>	<b>478</b>	<b>141</b>	<b>294</b>	<b>844</b>	<b>123</b>	<b>1</b>	<b>-</b>
1511400	COAL INVNTY-CRAIG	0									
<b>1511400 Total</b>			<b>611</b>	<b>9</b>	<b>153</b>	<b>45</b>	<b>94</b>	<b>270</b>	<b>39</b>	<b>0</b>	<b>-</b>
1511600	COAL INVNTY-DJ	0									
<b>1511600 Total</b>			<b>11,803</b>	<b>167</b>	<b>2,959</b>	<b>871</b>	<b>1,822</b>	<b>5,222</b>	<b>758</b>	<b>4</b>	<b>-</b>
1511700	COAL INVNTY-RG	0									
<b>1511700 Total</b>			<b>31,430</b>	<b>444</b>	<b>7,879</b>	<b>2,319</b>	<b>4,851</b>	<b>13,907</b>	<b>2,019</b>	<b>11</b>	<b>-</b>
1511900	COAL INVNTY-HAYDEN	0									
<b>1511900 Total</b>			<b>4,236</b>	<b>60</b>	<b>1,062</b>	<b>313</b>	<b>654</b>	<b>1,874</b>	<b>272</b>	<b>1</b>	<b>-</b>
1512180	NATURAL GAS-CLAY BAS	0									
<b>1512180 Total</b>			<b>793</b>	<b>11</b>	<b>199</b>	<b>59</b>	<b>122</b>	<b>351</b>	<b>51</b>	<b>0</b>	<b>-</b>
1514000	FUEL STK-FUEL OIL	0									
<b>1514000 Total</b>			<b>2,201</b>	<b>31</b>	<b>552</b>	<b>162</b>	<b>340</b>	<b>974</b>	<b>141</b>	<b>1</b>	<b>-</b>
1514300	OIL INVNTY-COLSTRIP	0									
<b>1514300 Total</b>			<b>82</b>	<b>1</b>	<b>21</b>	<b>6</b>	<b>13</b>	<b>36</b>	<b>5</b>	<b>0</b>	<b>-</b>
1514400	OIL INVNTY-CRAIG	0									
<b>1514400 Total</b>			<b>64</b>	<b>1</b>	<b>16</b>	<b>5</b>	<b>10</b>	<b>29</b>	<b>4</b>	<b>0</b>	<b>-</b>
1514900	OIL INVNTY-HAYDEN	0									
<b>1514900 Total</b>			<b>55</b>	<b>1</b>	<b>14</b>	<b>4</b>	<b>8</b>	<b>24</b>	<b>4</b>	<b>0</b>	<b>-</b>
1541000	PLNT M&S STK CNTRL	0									
			(148)	(3)	(40)	(11)	(19)	(65)	(9)	(0)	-
1541000	PLNT M&S STK CNTRL	1510									
			24,929	366	6,499	1,954	3,538	11,067	1,497	7	-
1541000	PLNT M&S STK CNTRL	1515									
			18,286	268	4,767	1,433	2,595	8,118	1,098	5	-
1541000	PLNT M&S STK CNTRL	1520									
			6,682	98	1,742	524	948	2,966	401	2	-
1541000	PLNT M&S STK CNTRL	1525									
			4,424	65	1,153	347	628	1,964	266	1	-
1541000	PLNT M&S STK CNTRL	1530									
			1	0	0	0	0	1	0	0	-
1541000	PLNT M&S STK CNTRL	1535									
			13,493	198	3,518	1,058	1,915	5,990	810	4	-
1541000	PLNT M&S STK CNTRL	1540									
			18,984	279	4,949	1,488	2,694	8,428	1,140	6	-
1541000	PLNT M&S STK CNTRL	1545									
			26,671	391	6,953	2,091	3,786	11,841	1,602	8	-
1541000	PLNT M&S STK CNTRL	1550									
			1,084	16	283	85	154	481	65	0	-
1541000	PLNT M&S STK CNTRL	1565									
			4,018	59	1,047	315	570	1,784	241	1	-
1541000	PLNT M&S STK CNTRL	1570									
			6,502	95	1,695	510	923	2,887	391	2	-
1541000	PLNT M&S STK CNTRL	1580									
			3,682	54	960	289	523	1,634	221	1	-
1541000	PLNT M&S STK CNTRL	1675									
			7	0	2	1	1	3	0	0	-
1541000	PLNT M&S STK CNTRL	1680									
			3	0	1	0	0	1	0	0	-
1541000	PLNT M&S STK CNTRL	1700									
			235	3	61	18	33	104	14	0	-
1541000	PLNT M&S STK CNTRL	1705									
			129	2	34	10	18	57	8	0	-
1541000	PLNT M&S STK CNTRL	1715									
			367	5	96	29	52	163	22	0	-
1541000	PLNT M&S STK CNTRL	1720									
			4	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL	1725									
			990	15	258	78	141	440	59	0	-
1541000	PLNT M&S STK CNTRL	1730									
			612	9	159	48	87	272	37	0	-
1541000	PLNT M&S STK CNTRL	1735									
			5	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL	1740									
			452	7	118	35	64	201	27	0	-
1541000	PLNT M&S STK CNTRL	1745									
			573	8	149	45	81	254	34	0	-
1541000	PLNT M&S STK CNTRL	1750									
			4	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL	1760									
			38	1	10	3	5	17	2	0	-



**Material & Supplies (Actuals)**

Year End: 06/2021

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 1765 Pryor Mountain	SG	4	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL 2005 CASPER STORE ROOM	WYP	568	-	-	-	568	-	-	-	-
1541000	PLNT M&S STK CNTRL 2010 BUFFALO STORE ROOM	WYP	153	-	-	-	153	-	-	-	-
1541000	PLNT M&S STK CNTRL 2015 DOUGLAS STORE ROOM	WYP	238	-	-	-	238	-	-	-	-
1541000	PLNT M&S STK CNTRL 2020 CODY STORE ROOM	WYP	681	-	-	-	681	-	-	-	-
1541000	PLNT M&S STK CNTRL 2030 WORLAND STORE ROOM	WYP	727	-	-	-	727	-	-	-	-
1541000	PLNT M&S STK CNTRL 2035 RIVERTON STORE ROOM	WYP	483	-	-	-	483	-	-	-	-
1541000	PLNT M&S STK CNTRL 2040 EVANSTON STORE ROOM	WYU	815	-	-	-	815	-	-	-	-
1541000	PLNT M&S STK CNTRL 2045 KEMMERER STORE ROOM	WYU	11	-	-	-	11	-	-	-	-
1541000	PLNT M&S STK CNTRL 2050 PINEDALE STORE ROOM	WYU	620	-	-	-	620	-	-	-	-
1541000	PLNT M&S STK CNTRL 2060 ROCK SPRINGS STORE ROOM	WYP	1,424	-	-	-	1,424	-	-	-	-
1541000	PLNT M&S STK CNTRL 2065 RAWLINS STORE ROOM	WYP	511	-	-	-	511	-	-	-	-
1541000	PLNT M&S STK CNTRL 2070 LARAMIE STORE ROOM	WYP	499	-	-	-	499	-	-	-	-
1541000	PLNT M&S STK CNTRL 2075 REXBERG STORE ROOM	IDU	1,700	-	-	-	-	-	1,700	-	-
1541000	PLNT M&S STK CNTRL 2085 SHELLY STORE ROOM	IDU	826	-	-	-	-	-	826	-	-
1541000	PLNT M&S STK CNTRL 2090 PRESTON STORE ROOM	IDU	80	-	-	-	-	-	80	-	-
1541000	PLNT M&S STK CNTRL 2095 LAVA HOT SPRINGS STORE ROOM	IDU	152	-	-	-	-	-	152	-	-
1541000	PLNT M&S STK CNTRL 2100 MONTPELIER STORE ROOM	IDU	254	-	-	-	-	-	254	-	-
1541000	PLNT M&S STK CNTRL 2110 BRIDGERLAND STORE ROOM	UT	493	-	-	-	-	493	-	-	-
1541000	PLNT M&S STK CNTRL 2205 TREMONTON STORE ROOM	UT	398	-	-	-	-	398	-	-	-
1541000	PLNT M&S STK CNTRL 2210 OGDEN STORE ROOM	UT	1,612	-	-	-	-	1,612	-	-	-
1541000	PLNT M&S STK CNTRL 2215 LAYTON STORE ROOM	UT	1,138	-	-	-	-	1,138	-	-	-
1541000	PLNT M&S STK CNTRL 2220 SALT LAKE METRO STORE ROOM	UT	9,330	-	-	-	-	9,330	-	-	-
1541000	PLNT M&S STK CNTRL 2230 JORDAN VALLEY STORE ROOM	UT	1,036	-	-	-	-	1,036	-	-	-
1541000	PLNT M&S STK CNTRL 2235 PARK CITY STORE ROOM	UT	1,462	-	-	-	-	1,462	-	-	-
1541000	PLNT M&S STK CNTRL 2240 TOOELE STORE ROOM	UT	567	-	-	-	-	567	-	-	-
1541000	PLNT M&S STK CNTRL 2245 WASATCH RESTORATION CENTER	UT	691	-	-	-	-	691	-	-	-
1541000	PLNT M&S STK CNTRL 2400 PLNT M&S STK CNTRL EAGLE MOUNTAIN	UT	362	-	-	-	-	362	-	-	-
1541000	PLNT M&S STK CNTRL 2405 AMERICAN FORK STORE ROOM	UT	1,796	-	-	-	-	1,796	-	-	-
1541000	PLNT M&S STK CNTRL 2410 SANTAQUIN STORE ROOM	UT	565	-	-	-	-	565	-	-	-
1541000	PLNT M&S STK CNTRL 2415 DELTA STORE ROOM	UT	528	-	-	-	-	528	-	-	-
1541000	PLNT M&S STK CNTRL 2420 VERNAL STORE ROOM	UT	744	-	-	-	-	744	-	-	-
1541000	PLNT M&S STK CNTRL 2425 PRICE STORE ROOM	UT	688	-	-	-	-	688	-	-	-
1541000	PLNT M&S STK CNTRL 2430 MOAB STORE ROOM	UT	866	-	-	-	-	866	-	-	-
1541000	PLNT M&S STK CNTRL 2435 BLANDING STORE ROOM	UT	100	-	-	-	-	100	-	-	-
1541000	PLNT M&S STK CNTRL 2445 RICHFIELD STORE ROOM	UT	124	-	-	-	-	124	-	-	-
1541000	PLNT M&S STK CNTRL 2450 CEDAR CITY STORE ROOM	UT	1,401	-	-	-	-	1,401	-	-	-
1541000	PLNT M&S STK CNTRL 2455 MILFORD STORE ROOM	UT	352	-	-	-	-	352	-	-	-
1541000	PLNT M&S STK CNTRL 2460 WASHINGTON STORE ROOM	UT	615	-	-	-	-	615	-	-	-
1541000	PLNT M&S STK CNTRL 2620 WALLA WALLA STORE ROOM	WA	2,264	-	-	2,264	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2630 YAKIMA STORE ROOM	WA	392	-	-	392	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2635 ENTERPRISE STORE ROOM	OR	233	-	233	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2640 PENDLETON STORE ROOM	OR	962	-	962	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2650 HOOD RIVER STORE ROOM	OR	523	-	523	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2655 PORTLAND METRO - STORE ROOM	OR	12,978	-	12,978	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2660 ASTORIA STORE ROOM	OR	1,311	-	1,311	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2665 MADRAS STORE ROOM	OR	100	-	100	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2675 BEND STORE ROOM	OR	2,048	-	2,048	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2805 ALBANY STORE ROOM	OR	249	-	249	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2810 LINCOLN CITY STORE ROOM	OR	219	-	219	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2830 ROSEBURG STORE ROOM	OR	3,572	-	3,572	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2835 COOS BAY STORE ROOM	OR	957	-	957	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2840 GRANTS PASS STORE ROOM	OR	1,388	-	1,388	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL 2845 MEDFORD STORE ROOM	OR	933	-	933	-	-	-	-	-	-





Material & Supplies (Actuals)  
 Year End: 06/2021  
 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	2850	KLAMATH FALLS STORE ROOM	OR	3,227	-	3,227	-	-	-	-	
1541000	PLNT M&S STK CNTRL	2855	LAKEVIEW STORE ROOM	OR	128	-	128	-	-	-	-	
1541000	PLNT M&S STK CNTRL	2860	ALTURAS STORE ROOM	CA	108	108	-	-	-	-	-	
1541000	PLNT M&S STK CNTRL	2865	MT SHASTA STORE ROOM	CA	268	268	-	-	-	-	-	
1541000	PLNT M&S STK CNTRL	2870	YREKA STORE ROOM	CA	1,605	1,605	-	-	-	-	-	
1541000	PLNT M&S STK CNTRL	2875	CRESENT CITY STORE ROOM	CA	592	592	-	-	-	-	-	
1541000	PLNT M&S STK CNTRL	5005	TREMONTON STORE ROOM	SO	146	3	40	11	19	64	9	
1541000	PLNT M&S STK CNTRL	5110	MATERIAL PACKAGING CENTER - WEST	OR	0	-	0	-	-	-	-	
1541000	PLNT M&S STK CNTRL	5115	DEMC - SLC	SNPD	150	5	40	10	14	73	8	
1541000	PLNT M&S STK CNTRL	5120	DEMC - MEDFORD	OR	64	-	64	-	-	-	-	
1541000	PLNT M&S STK CNTRL	5125	DEMC - OREGON	OR	10,333	-	10,333	-	-	-	-	
1541000	PLNT M&S STK CNTRL	5130	MEDFORD HUB	OR	9,873	-	9,873	-	-	-	-	
1541000	PLNT M&S STK CNTRL	5135	YAKIMA HUB	WA	8,275	-	-	8,275	-	-	-	
1541000	PLNT M&S STK CNTRL	5140	PRESTON HUB	IDU	3,710	-	-	-	-	3,710	-	
1541000	PLNT M&S STK CNTRL	5150	RICHFIELD HUB	UT	4,586	-	-	-	4,586	-	-	
1541000	PLNT M&S STK CNTRL	5155	CASPER HUB	WYP	6,248	-	-	6,248	-	-	-	
1541000	PLNT M&S STK CNTRL	5160	SALT LAKE METRO HUB	UT	30,718	-	-	-	30,718	-	-	
1541000	PLNT M&S STK CNTRL	5200	UTAH TRANSPORTATION BUILDING	SNPD	16	1	4	1	2	8	1	
1541000	PLNT M&S STK CNTRL	5300	METER TEST WAREHOUSE	UT	3	-	-	-	-	3	-	
<b>1541000 Total</b>					<b>274,818</b>	<b>4,519</b>	<b>83,599</b>	<b>21,303</b>	<b>31,754</b>	<b>118,935</b>	<b>14,668</b>	<b>39</b>
1541500	OTHER M&S	0	M&S GLENROCK COAL MINE	SE	198	3	50	15	30	87	13	
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SE	(198)	(3)	(50)	(15)	(30)	(87)	(13)	
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SO	137	3	37	11	18	60	8	
<b>1541500 Total</b>					<b>137</b>	<b>3</b>	<b>37</b>	<b>11</b>	<b>18</b>	<b>60</b>	<b>8</b>	<b>0</b>
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SG	2,154	32	562	169	306	956	129	
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SO	(1,380)	(30)	(375)	(106)	(181)	(606)	(81)	
<b>1541900 Total</b>					<b>775</b>	<b>1</b>	<b>187</b>	<b>63</b>	<b>124</b>	<b>350</b>	<b>49</b>	<b>0</b>
1549900	CR-OBSOL&SURPL INV	102930	SB Asset # 120930	SO	(27)	(1)	(7)	(2)	(4)	(12)	(2)	
1549900	CR-OBSOL&SURPL INV	120930	INVENTORY RESERVE POWER SUPPLY	SG	(915)	(13)	(239)	(72)	(130)	(406)	(55)	
1549900	CR-OBSOL&SURPL INV	120930	INVENTORY RESERVE POWER SUPPLY	SO	(12)	(0)	(3)	(1)	(2)	(5)	(1)	
1549900	CR-OBSOL&SURPL INV	120932	Inventory Reserve - RMP (T&D)	SNPD	(894)	(32)	(237)	(57)	(86)	(435)	(48)	
1549900	CR-OBSOL&SURPL INV	120933	Inventory Reserve - PP (T&D)	SNPD	(580)	(21)	(154)	(37)	(56)	(283)	(31)	
<b>1549900 Total</b>					<b>(2,430)</b>	<b>(67)</b>	<b>(640)</b>	<b>(169)</b>	<b>(277)</b>	<b>(1,142)</b>	<b>(136)</b>	<b>(0)</b>
2531600	WORK CAP DEP-UAMPS	289920	WORKING CAPITAL DEPOSIT - UAMPS	SE	(2,806)	(40)	(703)	(207)	(433)	(1,242)	(180)	
<b>2531600 Total</b>					<b>(2,806)</b>	<b>(40)</b>	<b>(703)</b>	<b>(207)</b>	<b>(433)</b>	<b>(1,242)</b>	<b>(180)</b>	<b>(1)</b>
2531700	WORKG CAP DEP-DG&T	289921	OTH DEF CR - WORKING CAPITAL DEPOS-DG&T	SE	(2,676)	(38)	(671)	(197)	(413)	(1,184)	(172)	
<b>2531700 Total</b>					<b>(2,676)</b>	<b>(38)</b>	<b>(671)</b>	<b>(197)</b>	<b>(413)</b>	<b>(1,184)</b>	<b>(172)</b>	<b>(1)</b>
2531800	WCD-PROVO-PLNT M&S	289922	OTH DEF CR - WCD - PROVO - PLANT M&S	SG	(273)	(4)	(71)	(21)	(39)	(121)	(16)	
<b>2531800 Total</b>					<b>(273)</b>	<b>(4)</b>	<b>(71)</b>	<b>(21)</b>	<b>(39)</b>	<b>(121)</b>	<b>(16)</b>	<b>(0)</b>
<b>Grand Total</b>					<b>474,499</b>	<b>7,300</b>	<b>133,618</b>	<b>36,051</b>	<b>62,677</b>	<b>207,230</b>	<b>27,516</b>	<b>107</b>

# **B14. CASH WORKING CAPITAL**



Cash Working Capital (Actuals)  
 12 Month Average: 06/2021  
 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		3	0	1	0	0	1	0	0
<b>1430000 Total</b>				<b>3</b>	<b>0</b>	<b>1</b>	<b>0</b>	<b>0</b>	<b>1</b>	<b>0</b>	<b>0</b>
1431000	EMP ACCOUNTS REC	0	4,636	102	1,260	356	587	2,037	271	1	-
<b>1431000 Total</b>			<b>4,636</b>	<b>102</b>	<b>1,260</b>	<b>356</b>	<b>587</b>	<b>2,037</b>	<b>271</b>	<b>1</b>	<b>-</b>
1431500	INC TAXES RECEIVABLE	0	(70)	(2)	(19)	(5)	(9)	(31)	(4)	(0)	-
1431500	INC TAXES RECEIVABLE	116133	208	5	56	16	26	91	12	0	-
1431500	INC TAXES RECEIVABLE	116134	(28)	(1)	(8)	(2)	(4)	(12)	(2)	(0)	-
<b>1431500 Total</b>			<b>110</b>	<b>2</b>	<b>30</b>	<b>8</b>	<b>14</b>	<b>48</b>	<b>6</b>	<b>0</b>	<b>-</b>
1433000	JOINT OWNER REC	0	1,331	29	362	102	168	585	78	0	-
<b>1433000 Total</b>			<b>1,331</b>	<b>29</b>	<b>362</b>	<b>102</b>	<b>168</b>	<b>585</b>	<b>78</b>	<b>0</b>	<b>-</b>
1436000	OTH ACCT REC	0	27,753	612	7,541	2,130	3,513	12,193	1,621	6	-
<b>1436000 Total</b>			<b>27,753</b>	<b>612</b>	<b>7,541</b>	<b>2,130</b>	<b>3,513</b>	<b>12,193</b>	<b>1,621</b>	<b>6</b>	<b>-</b>
1437000	CSS OAR BILLINGS	0	6,836	151	1,858	525	865	3,003	399	1	-
<b>1437000 Total</b>			<b>6,836</b>	<b>151</b>	<b>1,858</b>	<b>525</b>	<b>865</b>	<b>3,003</b>	<b>399</b>	<b>1</b>	<b>-</b>
1437100	CSS OAR BILLINGS-WOR	0	(2,032)	(45)	(552)	(156)	(257)	(893)	(119)	(0)	-
<b>1437100 Total</b>			<b>(2,032)</b>	<b>(45)</b>	<b>(552)</b>	<b>(156)</b>	<b>(257)</b>	<b>(893)</b>	<b>(119)</b>	<b>(0)</b>	<b>-</b>
2300000	ASSET RETIREMENT OBL	284915	(2,978)	-	-	-	-	-	-	-	(2,978)
<b>2300000 Total</b>			<b>(2,978)</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>(2,978)</b>
2320000	ACCOUNTS PAYABLE	210460	(1,860)	(26)	(466)	(137)	(273)	(823)	(119)	(1)	-
2320000	ACCOUNTS PAYABLE	210677	(1,192)	(17)	(299)	(88)	(175)	(527)	(77)	(0)	-
2320000	ACCOUNTS PAYABLE	211108	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	211109	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	211112	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	211115	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	211116	(10)	(0)	(3)	(1)	(1)	(5)	(1)	(0)	-
2320000	ACCOUNTS PAYABLE	215077	(530)	(12)	(144)	(41)	(67)	(233)	(31)	(0)	-
2320000	ACCOUNTS PAYABLE	215078	(1,378)	(30)	(374)	(106)	(174)	(605)	(80)	(0)	-
2320000	ACCOUNTS PAYABLE	215080	(3,163)	(70)	(859)	(243)	(400)	(1,390)	(185)	(1)	-
2320000	ACCOUNTS PAYABLE	215082	(41)	(1)	(11)	(3)	(5)	(18)	(2)	(0)	-
2320000	ACCOUNTS PAYABLE	215084	(37)	(1)	(10)	(3)	(5)	(16)	(2)	(0)	-
2320000	ACCOUNTS PAYABLE	215085	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
2320000	ACCOUNTS PAYABLE	215086	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	215088	2	0	1	0	0	1	0	0	-
2320000	ACCOUNTS PAYABLE	215095	(104)	(2)	(28)	(8)	(13)	(46)	(6)	(0)	-
2320000	ACCOUNTS PAYABLE	215112	(15)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
2320000	ACCOUNTS PAYABLE	215116	(37)	(1)	(10)	(3)	(5)	(16)	(2)	(0)	-
2320000	ACCOUNTS PAYABLE	215350	4	0	1	0	1	2	0	0	-
2320000	ACCOUNTS PAYABLE	215351	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	215356	(23)	(1)	(6)	(2)	(3)	(10)	(1)	(0)	-
2320000	ACCOUNTS PAYABLE	215357	(5)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	-
2320000	ACCOUNTS PAYABLE	215425	(19)	-	-	-	-	-	-	-	(19)
2320000	ACCOUNTS PAYABLE	215439	(3,331)	(49)	(868)	(261)	(448)	(1,479)	(200)	(1)	-
2320000	ACCOUNTS PAYABLE	235230	(64)	(1)	(16)	(5)	(9)	(28)	(4)	(0)	-
2320000	ACCOUNTS PAYABLE	235599	(762)	(17)	(207)	(58)	(96)	(335)	(44)	(0)	-
2320000	ACCOUNTS PAYABLE	240330	(54)	(1)	(15)	(4)	(7)	(24)	(3)	(0)	-
<b>2320000 Total</b>			<b>(12,622)</b>	<b>(229)</b>	<b>(3,322)</b>	<b>(964)</b>	<b>(1,684)</b>	<b>(5,562)</b>	<b>(760)</b>	<b>(3)</b>	<b>(19)</b>
2533000	O DEF CR-MISC PPL	289517	(7,150)	(101)	(1,792)	(528)	(1,048)	(3,164)	(459)	(2)	-
<b>2533000 Total</b>			<b>(7,150)</b>	<b>(101)</b>	<b>(1,792)</b>	<b>(528)</b>	<b>(1,048)</b>	<b>(3,164)</b>	<b>(459)</b>	<b>(2)</b>	<b>-</b>
<b>Grand Total</b>			<b>15,886</b>	<b>522</b>	<b>5,384</b>	<b>1,475</b>	<b>2,159</b>	<b>8,249</b>	<b>1,038</b>	<b>2</b>	<b>(2,997)</b>

# **B15. MISC. RATE BASE**



Miscellaneous Rate Base (Actuals)  
 Year End: 06/2021  
 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	2,123	37,725	11,343	20,538	64,244	8,691	42	-
1140000	EL PLT ACQUIST ADJ	1140000	ELECTRIC PLANT ACQUISITION ADJUSTMENTS	UT	11,764	-	-	-	-	11,764	-	-	-
<b>1140000 Total</b>					<b>156,468</b>	<b>2,123</b>	<b>37,725</b>	<b>11,343</b>	<b>20,538</b>	<b>76,005</b>	<b>8,691</b>	<b>42</b>	<b>-</b>
1150000	Acc Prov El Pt Acq Ad	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	SG	(137,980)	(2,025)	(35,972)	(10,816)	(19,584)	(61,256)	(8,287)	(40)	-
1150000	Acc Prov El Pt Acq Ad	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	UT	(1,898)	-	-	-	-	(1,898)	-	-	-
<b>1150000 Total</b>					<b>(139,878)</b>	<b>(2,025)</b>	<b>(35,972)</b>	<b>(10,816)</b>	<b>(19,584)</b>	<b>(63,154)</b>	<b>(8,287)</b>	<b>(40)</b>	<b>-</b>
1156000	ACCUM PROV-CRAIG/HAY	0	ACCUM PROV FOR ASSET ACQ ADJ - CRAIG/HAY	UT	(1,715)	-	-	-	-	(1,715)	-	-	-
<b>1156000 Total</b>					<b>(1,715)</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>(1,715)</b>	<b>-</b>	<b>-</b>	<b>-</b>
1281000	Oth Special Funds-Pn	0	Other special funds - Pensions	SO	28,657	632	7,787	2,200	3,767	12,591	1,674	6	-
<b>1281000 Total</b>					<b>28,657</b>	<b>632</b>	<b>7,787</b>	<b>2,200</b>	<b>3,767</b>	<b>12,591</b>	<b>1,674</b>	<b>6</b>	<b>-</b>
1651000	PREPAY-INSURANCE	132008	PREPAID INSURANCE - PUBLIC LIABILITY & P	SO	801	18	218	61	105	352	47	0	-
1651000	PREPAY-INSURANCE	132012	PREPAID INSURANCE - ALLPURPOSE INSURANCE	SO	439	10	119	34	58	193	26	0	-
1651000	PREPAY-INSURANCE	132016	PREPAID INS-MINORITY OWNED PLANTS	SO	595	13	162	46	78	262	35	0	-
1651000	PREPAY-INSURANCE	132045	PREPAID WORKERS COMPENSATION	SO	344	8	94	26	45	151	20	0	-
1651000	PREPAY-INSURANCE	132055	PREPAID EMPLOYEE BENEFIT COSTS	SO	8	0	2	1	1	4	0	0	-
<b>1651000 Total</b>					<b>2,188</b>	<b>48</b>	<b>595</b>	<b>168</b>	<b>288</b>	<b>961</b>	<b>128</b>	<b>0</b>	<b>-</b>
1652000	PREPAY-TAXES	132109	UTE-PREPAID POSSESSORY INTEREST	GPS	18	0	5	1	2	8	1	0	-
1652000	PREPAY-TAXES	132110	SHO-BAN-PREPAID POSSESSORY INTEREST	GPS	114	3	31	9	15	50	7	0	-
1652000	PREPAY-TAXES	132111	Goshute - Prepaid Possessory Interest	GPS	17	0	5	1	2	7	1	0	-
1652000	PREPAY-TAXES	132200	"Prepaid Taxes (Federal, State, Local)"	SO	30	1	8	2	4	13	2	0	-
<b>1652000 Total</b>					<b>179</b>	<b>4</b>	<b>49</b>	<b>14</b>	<b>24</b>	<b>79</b>	<b>10</b>	<b>0</b>	<b>-</b>
1652100	PREPAY - OTHER	132097	Prepaid CA GHG Cap & Trade Allowances	OTHER	20,982	-	-	-	-	-	-	-	20,982
1652100	PREPAY - OTHER	132098	Prepaid - CA GHG Wholesale	OTHER	9,164	-	-	-	-	-	-	-	9,164
1652100	PREPAY - OTHER	132310	PREPAID RATING AGENCY	SO	139	3	38	11	18	61	8	0	-
1652100	PREPAY - OTHER	132548	Prepaid-FSA O&M - Cedar Springs II	SG	157	2	41	12	22	70	9	0	-
1652100	PREPAY - OTHER	132551	Prepaid-FSA O&M - Dunlap	SG	208	3	54	16	30	92	12	0	-
1652100	PREPAY - OTHER	132552	Prepaid-FSA O&M - Ekola Flats	SG	34	0	9	3	5	15	2	0	-
1652100	PREPAY - OTHER	132557	Prepaid-FSA O&M - Glenrock I	SG	185	3	48	15	26	82	11	0	-
1652100	PREPAY - OTHER	132558	Prepaid-FSA O&M - Glenrock III	SG	146	2	38	11	21	65	9	0	-
1652100	PREPAY - OTHER	132561	Prepaid-FSA O&M - Goodnoe Hills	SG	220	3	57	17	31	98	13	0	-
1652100	PREPAY - OTHER	132564	Prepaid-FSA O&M - High Plains	SG	556	8	145	44	79	247	33	0	-
1652100	PREPAY - OTHER	132567	Prepaid-FSA O&M - Leaning Juniper	SG	282	4	74	22	40	125	17	0	-
1652100	PREPAY - OTHER	132574	Prepaid-FSA O&M - McFadden Ridge	SG	107	2	28	8	15	47	6	0	-
1652100	PREPAY - OTHER	132576	Prepaid-FSA O&M - Pryor Mtn	SG	5	0	1	0	1	2	0	0	-
1652100	PREPAY - OTHER	132577	Prepaid-FSA O&M - Rolling Hills	SG	278	4	73	22	39	123	17	0	-
1652100	PREPAY - OTHER	132580	Prepaid-FSA O&M - Seven Mile I	SG	185	3	48	15	26	82	11	0	-
1652100	PREPAY - OTHER	132581	Prepaid-FSA O&M - Seven Mile II	SG	37	1	10	3	5	16	2	0	-
1652100	PREPAY - OTHER	132620	PREPAYMENTS - WATER RIGHTS LEASE	SG	643	9	168	50	91	286	39	0	-
1652100	PREPAY - OTHER	132621	Prepayments - Water Rights (Ferron Canal)	SG	223	3	58	17	32	99	13	0	-
1652100	PREPAY - OTHER	132622	Prepayments - Water Rights (Hntgtn-Clev)	SG	264	4	69	21	37	117	16	0	-
1652100	PREPAY - OTHER	132650	PREPAID DUES	SO	3,478	77	945	267	457	1,528	203	1	-
1652100	PREPAY - OTHER	132700	PREPAID RENT	GPS	11	0	3	1	1	5	1	0	-
1652100	PREPAY - OTHER	132740	PREPAID O&M WIND	SG	91	1	24	7	13	41	5	0	-
1652100	PREPAY - OTHER	132755	Prepaid Aircraft Maintenance Costs	SG	195	3	51	15	28	87	12	0	-
1652100	PREPAY - OTHER	132831	PREPAID BPA TRANSM - WINE COUNTRY	SG	16	0	4	1	2	7	1	0	-
1652100	PREPAY - OTHER	132900	PREPAYMENTS - OTHER	SE	72	1	18	5	11	32	5	0	-
1652100	PREPAY - OTHER	132900	PREPAYMENTS - OTHER	SO	1,341	30	364	103	176	589	78	0	-
1652100	PREPAY - OTHER	132901	PRE FEES - OREGON PUB UTIL COMMISSION	OR	4,077	-	4,077	-	-	-	-	-	-
1652100	PREPAY - OTHER	132903	PREP FEES-UTAH PUBLIC SERVICE COMMISSION	UT	6,934	-	-	-	-	6,934	-	-	-
1652100	PREPAY - OTHER	132904	PREP FEES-IDAHO PUB UTIL COMMISSION	IDU	284	-	-	-	-	-	284	-	-
1652100	PREPAY - OTHER	132910	Prepayments - Hardware & Software	SO	14,871	328	4,041	1,142	1,955	6,534	869	3	-
1652100	PREPAY - OTHER	132998	PREPAID INSURANCE	SE	(26)	(0)	(7)	(2)	(4)	(12)	(2)	(0)	-
1652100	PREPAY - OTHER	132999	PREPAY - RECLASS TO LT	SO	(2,640)	(58)	(717)	(203)	(347)	(1,160)	(154)	(1)	-
1652100	PREPAY - OTHER	134000	LT PREPAY RECLASS	SO	2,667	59	725	205	351	1,172	156	1	-
<b>1652100 Total</b>					<b>65,187</b>	<b>495</b>	<b>10,487</b>	<b>1,829</b>	<b>3,163</b>	<b>17,384</b>	<b>1,678</b>	<b>5</b>	<b>30,146</b>
2281000	ACC PROV-PROP INS	288711	Reg Liab - CA Property Insurance Reserve	CA	(929)	(929)	-	-	-	-	-	-	-
2281000	ACC PROV-PROP INS	288712	Reg Liab - OR Property Insurance Reserve	OR	20,938	-	20,938	-	-	-	-	-	-
2281000	ACC PROV-PROP INS	288713	Reg Liab - WA Property Insurance Reserve	WA	(114)	-	-	(114)	-	-	-	-	-
2281000	ACC PROV-PROP INS	288714	Reg Liab - ID Property Insurance Reserve	IDU	(1,060)	-	-	-	-	-	(1,060)	-	-
2281000	ACC PROV-PROP INS	288715	Reg Liab - UT Property Insurance Reserve	UT	(2,882)	-	-	-	-	(2,882)	-	-	-
2281000	ACC PROV-PROP INS	288716	Reg Liab - WY Property Insurance Reserve	WYP	(918)	-	-	-	(918)	-	-	-	-
2281000	ACC PROV-PROP INS	288749	RegL - Insurance Reserves - Reclass	OTHER	(20,938)	-	-	-	-	-	-	-	(20,938)
<b>2281000 Total</b>					<b>(5,903)</b>	<b>(929)</b>	<b>20,938</b>	<b>(114)</b>	<b>(918)</b>	<b>(2,882)</b>	<b>(1,060)</b>	<b>-</b>	<b>(20,938)</b>
2282100	ACC PRV IN & DAMAG	280311	ACC. PROV. I & D - EXCL. AUTO	SO	(256,406)	(5,654)	(69,673)	(19,683)	(33,709)	(112,653)	(14,980)	(53)	-
<b>2282100 Total</b>					<b>(256,406)</b>	<b>(5,654)</b>	<b>(69,673)</b>	<b>(19,683)</b>	<b>(33,709)</b>	<b>(112,653)</b>	<b>(14,980)</b>	<b>(53)</b>	<b>-</b>
2282400	ACCUM PRV FR I&D-OR	288700	Reg Liab - OR Injuries & Damages Reserve	OR	(12,416)	-	(12,416)	-	-	-	-	-	-



Miscellaneous Rate Base (Actuals)  
 Year End: 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other		
<b>2282400 Total</b>			<b>(12,416)</b>	-	<b>(12,416)</b>	-	-	-	-	-	-		
2282500	Acc Prov I&D-Insur	156909	Insurance Reim Receivable (I&D)-NonCurr	SO	115,250	2,541	31,317	8,847	15,152	50,636	6,733	24	-
<b>2282500 Total</b>			<b>115,250</b>	<b>2,541</b>	<b>31,317</b>	<b>8,847</b>	<b>15,152</b>	<b>50,636</b>	<b>6,733</b>	<b>24</b>	-		
2283000	PEN/BENFT-SICK	280349	SUPPL. PENSION BENEFITS (RETIRE ALLOW)	SO	(1,612)	(36)	(438)	(124)	(212)	(708)	(94)	(0)	-
<b>2283000 Total</b>			<b>(1,612)</b>	<b>(36)</b>	<b>(438)</b>	<b>(124)</b>	<b>(212)</b>	<b>(708)</b>	<b>(94)</b>	<b>(0)</b>	-		
2283400	POST-RETIREMENT BEN	280329	FAS 106-Contra Liability-Medicare Subsid	SO	22,389	494	6,084	1,719	2,943	9,837	1,308	5	-
2283400	POST-RETIREMENT BEN	280440	FAS 158 PR Liab Medicare Sub (Non-Deduct)	SO	(5,429)	(120)	(1,475)	(417)	(714)	(2,385)	(317)	(1)	-
2283400	POST-RETIREMENT BEN	280454	FAS 158 PR Liab Reg Medicare (Non-Deduct)	SO	5,429	120	1,475	417	714	2,385	317	1	-
2283400	POST-RETIREMENT BEN	280456	FAS 106-Contra Liab-Med.Sub.Claims	SO	(16,960)	(374)	(4,608)	(1,302)	(2,230)	(7,451)	(991)	(3)	-
2283400	POST-RETIREMENT BEN	280457	FAS 158 - CONTRA LIA - Reg Medicare	SO	(5,429)	(120)	(1,475)	(417)	(714)	(2,385)	(317)	(1)	-
<b>2283400 Total</b>			<b>0</b>	-	-	-	-	-	-	-	-	-	
2283500	PENSIONS	280350	Pension - Local 57	SO	(515)	(11)	(140)	(40)	(68)	(226)	(30)	(0)	-
2283500	PENSIONS	280355	FAS 158 Pension Liability	SO	(74,432)	(1,641)	(20,226)	(5,714)	(9,786)	(32,702)	(4,349)	(15)	-
2283500	PENSIONS	280365	FAS 158 Pension Liab-Rcls to Current	SO	515	11	140	40	68	226	30	0	-
<b>2283500 Total</b>			<b>(74,432)</b>	<b>(1,641)</b>	<b>(20,226)</b>	<b>(5,714)</b>	<b>(9,786)</b>	<b>(32,702)</b>	<b>(4,349)</b>	<b>(15)</b>	-		
2284100	AC MIS OP PR-OTHER	289320	CHEHALIS WA EFSEC C02 MITIGATION OBLIG	SG	(235)	(3)	(61)	(18)	(33)	(104)	(14)	(0)	-
<b>2284100 Total</b>			<b>(235)</b>	<b>(3)</b>	<b>(61)</b>	<b>(18)</b>	<b>(33)</b>	<b>(104)</b>	<b>(14)</b>	<b>(0)</b>	-		
2300000	ASSET RETIREMENT OBL	284918	ARO LIAB - TROJAN NUCLEAR PLANT	TROJD	(5,566)	(81)	(1,441)	(432)	(802)	(2,470)	(338)	(2)	-
<b>2300000 Total</b>			<b>(5,566)</b>	<b>(81)</b>	<b>(1,441)</b>	<b>(432)</b>	<b>(802)</b>	<b>(2,470)</b>	<b>(338)</b>	<b>(2)</b>	-		
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	CA	(50)	(50)	-	-	-	-	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	IDU	(15)	-	-	-	-	-	(15)	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	OR	(204)	-	(204)	-	-	-	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	UT	(62)	-	-	-	-	(62)	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	WA	(18)	-	-	(18)	-	-	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	WYP	(33)	-	-	-	(33)	-	-	-	-
<b>2530000 Total</b>			<b>(383)</b>	<b>(50)</b>	<b>(204)</b>	<b>(18)</b>	<b>(33)</b>	<b>(62)</b>	<b>(15)</b>	<b>-</b>	<b>-</b>	<b>-</b>	
2533500	OTH DEF CR-PEN & BEN	280370	PENSION LIAB-UMWA WITHDRAWAL OBLIG	SE	(115,119)	(1,627)	(28,858)	(8,494)	(17,768)	(50,938)	(7,395)	(39)	-
<b>2533500 Total</b>			<b>(115,119)</b>	<b>(1,627)</b>	<b>(28,858)</b>	<b>(8,494)</b>	<b>(17,768)</b>	<b>(50,938)</b>	<b>(7,395)</b>	<b>(39)</b>	-		
2539900	OTH DEF CR - OTHER	0	Fossil Rock Fuels Entries	SE	(5,006)	(71)	(1,255)	(369)	(773)	(2,215)	(322)	(2)	-
2539900	OTH DEF CR - OTHER	230155	EMPLOYEE HOUSING SECURITY DEPOSITS	CA	(22)	(22)	-	-	-	-	-	-	-
2539900	OTH DEF CR - OTHER	289341	Accrued Royalties-Reg Rcvry-Noncurrent	SE	(14,598)	(206)	(3,659)	(1,077)	(2,253)	(6,459)	(938)	(5)	-
2539900	OTH DEF CR - OTHER	289523	Govt Coal Lease Bonus Payment Liability	SE	5,006	71	1,255	369	773	2,215	322	2	-
2539900	OTH DEF CR - OTHER	289540	Westmoreland Kemmerer Payable-NonCurr	SG	(2,239)	(33)	(584)	(175)	(318)	(984)	(134)	(1)	-
2539900	OTH DEF CR - OTHER	289913	MCI - F.O.G. WIRE LEASE	SG	(2,044)	(30)	(533)	(160)	(290)	(907)	(123)	(1)	-
2539900	OTH DEF CR - OTHER	289914	TRANSMISSION SERVICE DEPOSITS - THIRD PA	SG	(1,993)	(29)	(520)	(156)	(283)	(885)	(120)	(1)	-
2539900	OTH DEF CR - OTHER	289925	TRANSM CONST SECURITY DEPOSITS	SG	(11,480)	(168)	(2,993)	(900)	(1,629)	(5,096)	(689)	(3)	-
2539900	OTH DEF CR - OTHER	289927	Transm Deposit - Readiness Fin Security	SG	(43,780)	(642)	(11,414)	(3,432)	(6,214)	(19,436)	(2,629)	(13)	-
2539900	OTH DEF CR - OTHER	289928	Transmission Deposits-Site Control	SG	(260)	(4)	(68)	(20)	(37)	(115)	(16)	(0)	-
2539900	OTH DEF CR - OTHER	289955	Accrued Right-of-Way Obligations	SG	(2,053)	(30)	(535)	(161)	(291)	(911)	(123)	(1)	-
<b>2539900 Total</b>			<b>(78,468)</b>	<b>(1,165)</b>	<b>(20,305)</b>	<b>(6,082)</b>	<b>(11,315)</b>	<b>(34,805)</b>	<b>(4,772)</b>	<b>(24)</b>	<b>-</b>		
2540000	REGULATORY LIAB	231010	Reg Liab Current - Blue Sky	OTHER	(8,004)	-	-	-	-	-	-	-	(8,004)
2540000	REGULATORY LIAB	231020	Reg Liab Current - DSM	OTHER	(4,027)	-	-	-	-	-	-	-	(4,027)
2540000	REGULATORY LIAB	231045	Reg Liab Current - GHG Allowances	OTHER	(544)	-	-	-	-	-	-	-	(544)
2540000	REGULATORY LIAB	231050	Reg Liab Current - Def Net Power Costs	OTHER	(6,798)	-	-	-	-	-	-	-	(6,798)
2540000	REGULATORY LIAB	231060	Reg Liab Current - BPA Balancing Accts	OTHER	(1,100)	-	-	-	-	-	-	-	(1,100)
2540000	REGULATORY LIAB	231080	Reg Liab Current - REC Sales	OTHER	(3,853)	-	-	-	-	-	-	-	(3,853)
2540000	REGULATORY LIAB	231090	Reg Liab Current - Solar Feed-In	OTHER	(5,075)	-	-	-	-	-	-	-	(5,075)
2540000	REGULATORY LIAB	231095	Reg Liab Current - Income Tax Related	OTHER	(86,342)	-	-	-	-	-	-	-	(86,342)
2540000	REGULATORY LIAB	231100	Reg Liab Current - Other	OTHER	(8,216)	-	-	-	-	-	-	-	(8,216)
2540000	REGULATORY LIAB	288001	Reg Liab - Excess Def Inc Taxes - CA	CA	(620)	(620)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288002	Reg Liab - Excess Def Inc Taxes - ID	IDU	(55)	-	-	-	-	-	(55)	-	-
2540000	REGULATORY LIAB	288005	Reg Liab - Excess Def Inc Taxes - WA	WA	(1,215)	-	-	(1,215)	-	-	-	-	-
2540000	REGULATORY LIAB	288006	Reg Liab - Excess Def Inc Taxes - WY	WYU	(546)	-	-	-	(546)	-	-	-	-
2540000	REGULATORY LIAB	288021	Reg Liab-FAS 158 Post-Retirement	SO	(11,203)	(247)	(3,044)	(860)	(1,473)	(4,922)	(654)	(2)	-
2540000	REGULATORY LIAB	288060	Reg L-WA Decoupling Mech Jul19-Jun20	OTHER	4,715	-	-	-	-	-	-	-	4,715
2540000	REGULATORY LIAB	288061	Reg L-WA Decoupling Mech Jul20-Jun21	OTHER	3,074	-	-	-	-	-	-	-	3,074
2540000	REGULATORY LIAB	288071	Contra Reg L-WA Decoupling Jul20-Jun21	OTHER	(4,710)	-	-	-	-	-	-	-	(4,710)
2540000	REGULATORY LIAB	288081	Reg Liab - Cholla Decomm - CA	CA	30	30	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288082	Reg Liab - Cholla Decomm - ID	IDU	113	-	-	-	-	-	113	-	-
2540000	REGULATORY LIAB	288083	Reg Liab - Cholla Decomm - OR	OR	(8,685)	-	(8,685)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288084	Reg Liab - Cholla Decomm - UT	UT	(19,601)	-	-	-	-	(19,601)	-	-	-
2540000	REGULATORY LIAB	288086	Reg Liab - Cholla Decomm - WY	WYP	280	-	-	-	280	-	-	-	-
2540000	REGULATORY LIAB	288099	RegL-Depr/Amortz Deferral-Bal Reclass	OTHER	(424)	-	-	-	-	-	-	-	(424)
2540000	REGULATORY LIAB	288108	FAS 109 - WA Flowthrough	WA	(3,279)	-	-	(3,279)	-	-	-	-	-
2540000	REGULATORY LIAB	288114	REG LIABILITY - OR GAIN-SALE EPUD ASSETS	OTHER	1	-	-	-	-	-	-	-	1
2540000	REGULATORY LIAB	288116	Calif Alternative Rate for Energy (CARE)	OTHER	(433)	-	-	-	-	-	-	-	(433)



Miscellaneous Rate Base (Actuals)  
 Year End: 06/2021  
 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	288159	RegL - Blue Sky - Recl to Curr	OTHER	8,004	-	-	-	-	-	8,004		
2540000	REGULATORY LIAB	288161	RL-Energy Savings Assistance (ESA)-CA	OTHER	(781)	-	-	-	-	-	(781)		
2540000	REGULATORY LIAB	288162	Reg Liab-CA Klamath River Dams Removal	CA	(265)	(265)	-	-	-	-	-		
2540000	REGULATORY LIAB	288165	Reg Liab - OR Enrgy	OTHER	(2,795)	-	-	-	-	-	(2,795)		
2540000	REGULATORY LIAB	288174	RegL - OR Asset Sale Gain-Balance Recl	OTHER	(2,124)	-	-	-	-	-	(2,124)		
2540000	REGULATORY LIAB	288211	Reg Liab - Non-Prot PP&E EDIT - CA	CA	(2,350)	(2,350)	-	-	-	-	-		
2540000	REGULATORY LIAB	288212	Reg Liab - Non-Prot PP&E EDIT - ID	IDU	(457)	-	-	-	(457)	-	-		
2540000	REGULATORY LIAB	288214	Reg Liab - Non-Prot PP&E EDIT - WA	WA	(23,998)	-	(23,998)	-	-	-	-		
2540000	REGULATORY LIAB	288215	Reg Liab - Non-Prot PP&E EDIT - WY	WYP	(44,167)	-	-	(44,167)	-	-	-		
2540000	REGULATORY LIAB	288232	Reg Liab - OR 2017 FERC Rate True-Up	OTHER	(9,861)	-	-	-	-	-	(9,861)		
2540000	REGULATORY LIAB	288240	Reg Liab - WA PCAM - CY 2016	OTHER	(1,143)	-	-	-	-	-	(1,143)		
2540000	REGULATORY LIAB	288243	Reg Liability - WA PCAM CY2018	OTHER	537	-	-	-	-	-	537		
2540000	REGULATORY LIAB	288246	Reg Liability - WA PCAM CY2019	OTHER	(1,814)	-	-	-	-	-	(1,814)		
2540000	REGULATORY LIAB	288248	Reg Liability - WA PCAM CY2020	OTHER	(13,661)	-	-	-	-	-	(13,661)		
2540000	REGULATORY LIAB	288249	Contra Reg Liability - WA PCAM CY2020	OTHER	(656)	-	-	-	-	-	(656)		
2540000	REGULATORY LIAB	288260	Reg Liability - WA PCAM CY2021	OTHER	1,669	-	-	-	-	-	1,669		
2540000	REGULATORY LIAB	288281	Reg Liab-Excess Income Tax Deferral-CA	OTHER	(4,084)	-	-	-	-	-	(4,084)		
2540000	REGULATORY LIAB	288283	Reg Liab-Excess Income Tax Deferral-OR	OTHER	(9,829)	-	-	-	-	-	(9,829)		
2540000	REGULATORY LIAB	288285	Reg Liab-Excess Income Tax Deferral-WA	OTHER	(9,227)	-	-	-	-	-	(9,227)		
2540000	REGULATORY LIAB	288295	RegL - BPA Balancing Accts - Recl to Cur	OTHER	1,100	-	-	-	-	-	1,100		
2540000	REGULATORY LIAB	288405	Reg Liab-OR Direct Access 5 yr Opt Out	OTHER	(7,587)	-	-	-	-	-	(7,587)		
2540000	REGULATORY LIAB	288406	Reg L-OR-Bridger Mine Accel Depr&Reclm	OR	(1,820)	(1,820)	-	-	-	-	-		
2540000	REGULATORY LIAB	288409	Reg Liab-WA-Plant Closure Cost Deferral	WA	(678)	-	(678)	-	-	-	-		
2540000	REGULATORY LIAB	288410	Reg Liab-WA-Bridger Mine Accel Depr	WA	(1,275)	-	(1,275)	-	-	-	-		
2540000	REGULATORY LIAB	288411	Reg Liab - WA-Accel Depr 2015 GRC	WA	(43,545)	-	(43,545)	-	-	-	-		
2540000	REGULATORY LIAB	288412	Reg Liab - Depr Decrease Deferral - OR	OTHER	(6,655)	-	-	-	-	-	(6,655)		
2540000	REGULATORY LIAB	288420	Reg Liab - CA GHG Allowance Revenues	OTHER	749	-	-	-	-	-	749		
2540000	REGULATORY LIAB	288422	Reg Liab - CA Solar (SOMAH)-GHG Funds	OTHER	(5,549)	-	-	-	-	-	(5,549)		
2540000	REGULATORY LIAB	288423	RegL - CA GHG Allowances - Recl to Curr	OTHER	544	-	-	-	-	-	544		
2540000	REGULATORY LIAB	288424	RegL - CA GHG Allowances - Balance Recl	OTHER	(749)	-	-	-	-	-	(749)		
2540000	REGULATORY LIAB	288443	RegL - OR RECs in Rates - Recl to Curr	OTHER	2,833	-	-	-	-	-	2,833		
2540000	REGULATORY LIAB	288444	RegL - UT RECs in Rates - Recl to Curr	OTHER	873	-	-	-	-	-	873		
2540000	REGULATORY LIAB	288446	RegL - WY RECs in Rates - Recl to Curr	OTHER	147	-	-	-	-	-	147		
2540000	REGULATORY LIAB	288453	RegL - OR RECs in Rates - Balance Recl	OTHER	(222)	-	-	-	-	-	(222)		
2540000	REGULATORY LIAB	288454	RegL - UT RECs in Rates - Balance Recl	OTHER	(1,946)	-	-	-	-	-	(1,946)		
2540000	REGULATORY LIAB	288456	RegL - WY RECs in Rates - Balance Recl	OTHER	(733)	-	-	-	-	-	(733)		
2540000	REGULATORY LIAB	288459	Reg Liab - Def RECs in Rates - Reclass	OTHER	(639)	-	-	-	-	-	(639)		
2540000	REGULATORY LIAB	288463	RegL - OR Def Exc NPC - Recl to Curr	OTHER	5,612	-	-	-	-	-	5,612		
2540000	REGULATORY LIAB	288465	RegL - WA Def Exc NPC - Recl to Curr	OTHER	1,143	-	-	-	-	-	1,143		
2540000	REGULATORY LIAB	288466	RegL - WY Def Exc NPC - Recl to Curr	OTHER	43	-	-	-	-	-	43		
2540000	REGULATORY LIAB	288470	Reg L-WA Decoupling Mechanism-Reclass	OTHER	(4,033)	-	-	-	-	-	(4,033)		
2540000	REGULATORY LIAB	288471	RegL - CA Def Exc NPC - Balance Reclass	OTHER	(529)	-	-	-	-	-	(529)		
2540000	REGULATORY LIAB	288476	RegL - WY Def Exc NPC - Balance Reclass	OTHER	(43)	-	-	-	-	-	(43)		
2540000	REGULATORY LIAB	288484	RegL - UT Solar Feed-In - Recl to Curr	OTHER	5,075	-	-	-	-	-	5,075		
2540000	REGULATORY LIAB	288494	RegL - UT Solar Feed-In - Balance Recl	OTHER	(19,905)	-	-	-	-	-	(19,905)		
2540000	REGULATORY LIAB	288857	RegL - DSM - WA - Reclass to Current	OTHER	4,027	-	-	-	-	-	4,027		
2540000	REGULATORY LIAB	288859	Reg Liab - DSM - WA - Balance Reclass	OTHER	(4,027)	-	-	-	-	-	(4,027)		
2540000	REGULATORY LIAB	288931	Reg Liab - Protected PP&E EDIT - CA	CA	(33,525)	(33,525)	-	-	-	-	-		
2540000	REGULATORY LIAB	288932	Reg Liab - Protected PP&E EDIT - ID	IDU	(85,514)	-	-	-	(85,514)	-	-		
2540000	REGULATORY LIAB	288933	Reg Liab - Protected PP&E EDIT - OR	OR	(374,952)	(374,952)	-	-	-	-	-		
2540000	REGULATORY LIAB	288934	Reg Liab - Protected PP&E EDIT - WA	WA	(90,029)	-	(90,029)	-	-	-	-		
2540000	REGULATORY LIAB	288935	Reg Liab - Protected PP&E EDIT - WY	WYP	(212,743)	-	-	(212,743)	-	-	-		
2540000	REGULATORY LIAB	288936	Reg Liab - Protected PP&E EDIT - UT	UT	(660,802)	-	-	-	(660,802)	-	-		
2540000	REGULATORY LIAB	288941	Reg Liab - Protected PP&E ARAM - CA	CA	(2,436)	(2,436)	-	-	-	-	-		
2540000	REGULATORY LIAB	288942	Reg Liab - Protected PP&E ARAM - ID	IDU	(7,865)	-	-	-	(7,865)	-	-		
2540000	REGULATORY LIAB	288943	Reg Liab - Protected PP&E ARAM - OR	OR	(2)	-	(2)	-	-	-	-		
2540000	REGULATORY LIAB	288944	Reg Liab - Protected PP&E ARAM - UT	UT	(49,875)	-	-	-	(49,875)	-	-		
2540000	REGULATORY LIAB	288945	Reg Liab - Protected PP&E ARAM - WA	WA	(14,617)	-	(14,617)	-	-	-	-		
2540000	REGULATORY LIAB	288946	Reg Liab - Protected PP&E ARAM - WY	WYU	(35,497)	-	-	(35,497)	-	-	-		
2540000	REGULATORY LIAB	288949	RegL - EDIT Deferral - Recl to Curr	OTHER	86,342	-	-	-	-	-	86,342		
2540000	REGULATORY LIAB	288995	RegL - Other - Recl to Curr	OTHER	8,216	-	-	-	-	-	8,216		
<b>2540000 Total</b>					<b>(1,834,604)</b>	<b>(39,411)</b>	<b>(388,503)</b>	<b>(179,496)</b>	<b>(294,145)</b>	<b>(735,199)</b>	<b>(94,432)</b>	<b>(2)</b>	<b>(103,414)</b>
<b>Grand Total</b>					<b>(2,158,808)</b>	<b>(46,779)</b>	<b>(469,201)</b>	<b>(206,590)</b>	<b>(345,374)</b>	<b>(879,737)</b>	<b>(116,823)</b>	<b>(98)</b>	<b>(94,206)</b>

# **B16. REGULATORY ASSETS**





**Regulatory Assests (Actuals)**

Year End: 06/2021

Allocation Method - Factor 2020 Protocol

(Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other			
1242000	PAC PWR-INT FREE LN	0		INT FREE-PPL	OTHER	834	-	-	-	-	-	834		
1242000	PAC PWR-INT FREE LN	0		INT FREE-PPL	WA	7	-	-	7	-	-	-		
<b>1242000 Total</b>						<b>841</b>	-	-	<b>7</b>	-	-	<b>834</b>		
1249000	RESV UNCOLL ESC&WZ	0		ESC - RESERVE	OTHER	(208)	-	-	-	-	-	(208)		
1249000	RESV UNCOLL ESC&WZ	0		ESC - RESERVE	UT	0	-	-	-	0	-	-		
1249000	RESV UNCOLL ESC&WZ	0		ESC - RESERVE	WA	(4)	-	-	(4)	-	-	-		
<b>1249000 Total</b>						<b>(212)</b>	-	-	<b>(4)</b>	<b>0</b>	-	<b>(208)</b>		
1823000	DSR REGULATORY ASSET	0		DSR REGULATORY ASSETS	OTHER	(57,048)	-	-	-	-	-	(57,048)		
<b>1823000 Total</b>						<b>(57,048)</b>	-	-	-	-	-	<b>(57,048)</b>		
1823700	OTH REGA-ENERGY WEST	186801		Reg Asset-Deer Creek-Elec Plt In Svc	SE	69,504	982	17,423	5,128	10,727	30,754	4,465	24	-
1823700	OTH REGA-ENERGY WEST	186802		Reg Asset-Deer Creek-EPIS Intangibles	SE	1,078	15	270	80	166	477	69	0	-
1823700	OTH REGA-ENERGY WEST	186805		Reg Asset-Deer Creek-CWIP	SE	3,960	56	993	292	611	1,752	254	1	-
1823700	OTH REGA-ENERGY WEST	186806		Reg Asset-Deer Creek-PS&I	SE	1,614	23	405	119	249	714	104	1	-
1823700	OTH REGA-ENERGY WEST	186811		Reg Asset-Deer Creek Sale-EPIS	SE	9,902	140	2,482	731	1,528	4,382	636	3	-
1823700	OTH REGA-ENERGY WEST	186812		Contra RA-DCM PP&E-OR-To G/L Bal Acct	OR	399	-	399	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186815		Reg Asset-Deer Creek Sale-CWIP	SE	94	1	23	7	14	41	6	0	-
1823700	OTH REGA-ENERGY WEST	186816		Contra RA-DCM PP&E-To Joint Owners	SE	(4,699)	(66)	(1,178)	(347)	(725)	(2,079)	(302)	(2)	-
1823700	OTH REGA-ENERGY WEST	186817		Contra RA-DCM PP&E-Amortz & Oth Adjs	CA	1,223	1,223	-	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186817		Contra RA-DCM PP&E-Amortz & Oth Adjs	OR	(2,032)	-	(2,032)	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186817		Contra RA-DCM PP&E-Amortz & Oth Adjs	SE	(79,015)	(1,117)	(19,808)	(5,830)	(12,196)	(34,963)	(5,076)	(27)	-
1823700	OTH REGA-ENERGY WEST	186817		Contra RA-DCM PP&E-Amortz & Oth Adjs	UT	281	-	-	-	-	281	-	-	-
1823700	OTH REGA-ENERGY WEST	186817		Contra RA-DCM PP&E-Amortz & Oth Adjs	WA	5,486	-	-	5,486	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186817		Contra RA-DCM PP&E-Amortz & Oth Adjs	WYU	814	-	-	-	814	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186820		Reg Asset-Deer Creek Mine ARO	SE	6,682	94	1,675	493	1,031	2,957	429	2	-
1823700	OTH REGA-ENERGY WEST	186825		Reg Asset-Deer Creek Mine M&S	SE	4,492	63	1,126	331	693	1,987	289	2	-
1823700	OTH REGA-ENERGY WEST	186826		Reg Asset-Deer Creek-Prepaid Royalties	SE	843	12	211	62	130	373	54	0	-
1823700	OTH REGA-ENERGY WEST	186828		Reg Asset-Deer Creek-Recovery Royalties	SE	14,598	206	3,659	1,077	2,253	6,459	938	5	-
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	23	404	119	249	713	104	1	-
1823700	OTH REGA-ENERGY WEST	186833		Reg Asset-Deer Creek-Nonunion Severance	SE	2,770	39	694	204	428	1,226	178	1	-
1823700	OTH REGA-ENERGY WEST	186835		Reg Asset-Deer Creek-Misc Closure Costs	SE	45,112	638	11,309	3,328	6,963	19,961	2,898	15	-
1823700	OTH REGA-ENERGY WEST	186836		Contra RA-DCM Closure-To Joint Owners	SE	(3,142)	(44)	(788)	(232)	(485)	(1,390)	(202)	(1)	-
1823700	OTH REGA-ENERGY WEST	186837		Contra RA-DCM Closure-Amortz & Oth Adjs	OTHER	(2,316)	-	-	-	-	-	-	-	(2,316)
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	42	747	220	460	1,318	191	1	-
1823700	OTH REGA-ENERGY WEST	186841		Contra Reg Asset-Deer Creek Aband-CA	CA	(1,332)	(1,332)	-	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186844		Contra Reg Asset-Deer Creek Aband-UT	UT	(924)	-	-	-	-	(924)	-	-	-
1823700	OTH REGA-ENERGY WEST	186845		Contra Reg Asset-Deer Creek Aband-WA	WA	(5,975)	-	-	(5,975)	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186846		Contra Reg Asset-Deer Creek Aband-WY	WYU	(376)	-	-	-	(376)	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186851		Contra Reg Asset-Deer Creek Closure-CA	CA	(1,260)	(1,260)	-	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186852		CONTRA REG ASSET-DEER CREEK CLOSURE-ID	IDU	(2,482)	-	-	-	-	-	(2,482)	-	-
1823700	OTH REGA-ENERGY WEST	186853		Contra Reg Asset-Deer Creek Closure-OR	OR	(9,264)	-	(9,264)	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186855		Contra Reg Asset-Deer Creek Closure-WA	WA	(4,292)	-	-	(4,292)	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186860		RA-Deer Creek-ROR Offset-Assets Sold	UT	(2,314)	-	-	-	-	(2,314)	-	-	-
1823700	OTH REGA-ENERGY WEST	186860		RA-Deer Creek-ROR Offset-Assets Sold	WYU	(107)	-	-	-	(107)	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186861		RA-Deer Creek-ROR Offset-Fuel Inventory	IDU	(1,519)	-	-	-	-	-	(1,519)	-	-
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	186862		RA-Deer Creek-ROR Offset-Fossil Rock	UT	(7,407)	-	-	-	-	(7,407)	-	-	-
1823700	OTH REGA-ENERGY WEST	186862		RA-Deer Creek-ROR Offset-Fossil Rock	WYU	(343)	-	-	-	(343)	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186863		RA-Deer Creek-ROR Offset-Note Intrst-ID	IDU	(191)	-	-	-	-	-	(191)	-	-
1823700	OTH REGA-ENERGY WEST	186870		RA-DC ROR Offset-Assets Sold-Amortz	UT	2,314	-	-	-	-	2,314	-	-	-
1823700	OTH REGA-ENERGY WEST	186870		RA-DC ROR Offset-Assets Sold-Amortz	WYP	107	-	-	-	107	-	-	-	-



**Regulatory Assests (Actuals)**

Year End: 06/2021

Allocation Method - Factor 2020 Protocol

(Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other	
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	186872	RA-DC ROR Offset-Fossil Rock-Amortz	UT	7,407	-	-	-	-	7,407	-	
1823700	OTH REGA-ENERGY WEST	186872	RA-DC ROR Offset-Fossil Rock-Amortz	WYP	343	-	-	-	343	-	-	
1823700	OTH REGA-ENERGY WEST	186881	Reg Asset-UMWA Pension Trust Oblig	SE	115,119	1,627	28,858	8,494	17,768	50,938	7,395	39
1823700	OTH REGA-ENERGY WEST	186886	Contra RA-UMWA Pens W/D-To Joint Owners	OTHER	(4,753)	-	-	-	-	-	-	(4,753)
1823700	OTH REGA-ENERGY WEST	186895	Contra Reg Asset-UMWA Pension Trust-WA	OTHER	(8,097)	-	-	-	-	-	-	(8,097)
<b>1823700</b>	<b>Total</b>				<b>117,057</b>	<b>1,365</b>	<b>37,610</b>	<b>9,495</b>	<b>16,704</b>	<b>58,744</b>	<b>8,239</b>	<b>66</b>
1823750	OTHER REG A-CHLA U4	185831	Reg Asset - Cholla Unrec Plant - CA	CA	4,408	4,408	-	-	-	-	-	-
1823750	OTHER REG A-CHLA U4	185836	Reg Asset - Cholla Unrec Plant - WY	WYP	41,909	-	-	-	41,909	-	-	-
1823750	OTHER REG A-CHLA U4	185864	Reg Asset-Cholla U4-Property Taxes-OR	OR	300	-	300	-	-	-	-	-
1823750	OTHER REG A-CHLA U4	185866	Reg Asset-Cholla U4-Nonunion Severance	SG	2,700	40	704	212	383	1,199	162	1
1823750	OTHER REG A-CHLA U4	185867	Reg Asset-Cholla U4-Safe Harbor Lease	SG	836	12	218	66	119	371	50	0
1823750	OTHER REG A-CHLA U4	185869	Reg Asset-Cholla U4-ID-O&M/Depr Savings	IDU	(806)	-	-	-	-	-	(806)	-
1823750	OTHER REG A-CHLA U4	185873	Contra Reg Asset-Cholla U4 Closure-OR	OR	(920)	-	(920)	-	-	-	-	-
1823750	OTHER REG A-CHLA U4	185874	Contra Reg Asset-Cholla U4 Closure-UT	UT	(1,556)	-	-	-	-	(1,556)	-	-
1823750	OTHER REG A-CHLA U4	185876	Contra Reg Asset-Cholla U4 Closure-WY	WYP	(517)	-	-	-	(517)	-	-	-
<b>1823750</b>	<b>Total</b>				<b>46,354</b>	<b>4,460</b>	<b>302</b>	<b>277</b>	<b>41,893</b>	<b>14</b>	<b>(594)</b>	<b>1</b>
1823870	DEFERRED PENSION	187017	FAS 158 Pen Liab Adj	SO	419,696	9,255	114,044	32,219	55,177	184,395	24,520	86
1823870	DEFERRED PENSION	187608	Reg Asset - Pension Settlement - CA	OTHER	473	-	-	-	-	-	-	473
1823870	DEFERRED PENSION	187621	Reg Asset FAS - 158	SO	(12,879)	(284)	(3,500)	(989)	(1,693)	(5,658)	(752)	(3)
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	CA	(127)	(127)	-	-	-	-	-	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	OTHER	(137)	-	-	-	-	-	-	(137)
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	SO	8,323	184	2,262	639	1,094	3,657	486	2
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)	-	-	-	-
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	11,203	247	3,044	860	1,473	4,922	654	2
<b>1823870</b>	<b>Total</b>				<b>420,914</b>	<b>9,274</b>	<b>115,851</b>	<b>32,069</b>	<b>54,639</b>	<b>183,750</b>	<b>24,908</b>	<b>88</b>
1823910	ENVIR CST UNDR AMORT	102465	UTAH METALS CLEANUP	SO	234	5	64	18	31	103	14	0
1823910	ENVIR CST UNDR AMORT	102570	D-SM RETAIL MINOR SITES	SO	1	0	0	0	0	0	0	0
1823910	ENVIR CST UNDR AMORT	103408	D-SM RETAIL MINOR SITES	SO	4,144	91	1,126	318	545	1,821	242	1
1823910	ENVIR CST UNDR AMORT	103420	ASTORIA YOUNGS BAY CLEANUP	SO	242	5	66	19	32	106	14	0
1823910	ENVIR CST UNDR AMORT	103426	SILVER BELL MINE ENVIRONMENTAL REMED	SO	5,239	116	1,424	402	689	2,302	306	1
1823910	ENVIR CST UNDR AMORT	103440	WASHINGTON NON-DEFERRED COSTS	WA	(42)	-	-	(42)	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103445	American Barrel (UT)	SO	352	8	96	27	46	155	21	0
1823910	ENVIR CST UNDR AMORT	103446	Astoria/Unocal (Downtown)	SO	1,023	23	278	79	135	450	60	0
1823910	ENVIR CST UNDR AMORT	103447	Big Fork Hydro Plant (MT)	SO	379	8	103	29	50	166	22	0
1823910	ENVIR CST UNDR AMORT	103448	Bridger Coal Fuel Oil Spill	SO	471	10	128	36	62	207	28	0
1823910	ENVIR CST UNDR AMORT	103449	Bridger FGD Pond 1 Closure	SO	601	13	163	46	79	264	35	0
1823910	ENVIR CST UNDR AMORT	103450	Bridger Plant Oil Spills	SO	352	8	96	27	46	155	21	0
1823910	ENVIR CST UNDR AMORT	103451	Cedar Stream Plant (UT)	SO	15	0	4	1	2	7	1	0
1823910	ENVIR CST UNDR AMORT	103452	Dave Johnston Oil Spill	SO	661	15	180	51	87	290	39	0
1823910	ENVIR CST UNDR AMORT	103453	Eugene MGP (50% PCRP)	SO	307	7	83	24	40	135	18	0
1823910	ENVIR CST UNDR AMORT	103454	Everett MGP (2/3 PCRP)	SO	10	0	3	1	1	5	1	0
1823910	ENVIR CST UNDR AMORT	103455	Hunter Fuel Oil Spills	SO	66	1	18	5	9	29	4	0
1823910	ENVIR CST UNDR AMORT	103456	Huntington Ash Landfill	SO	685	15	186	53	90	301	40	0
1823910	ENVIR CST UNDR AMORT	103457	Idaho Falls Pole Yard	SO	1,306	29	355	100	172	574	76	0
1823910	ENVIR CST UNDR AMORT	103458	Jordan Plant Substation	SO	96	2	26	7	13	42	6	0
1823910	ENVIR CST UNDR AMORT	103459	Little Mountain Gas Plant	SO	383	8	104	29	50	168	22	0
1823910	ENVIR CST UNDR AMORT	103460	Montague Ranch (CA)	SO	48	1	13	4	6	21	3	0
1823910	ENVIR CST UNDR AMORT	103461	Naughton FGD Pond Closure	SO	137	3	37	11	18	60	8	0
1823910	ENVIR CST UNDR AMORT	103462	Ogden MGP	SO	2,414	53	656	185	317	1,060	141	0
1823910	ENVIR CST UNDR AMORT	103464	Powerdale Hydro Plant	SO	0	0	0	0	0	0	0	0



**Regulatory Assests (Actuals)**

Year End: 06/2021

Allocation Method - Factor 2020 Protocol

(Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other		
1823910	ENVIR CST UNDR AMORT	103465	Tacoma A St. (25% PCRP)	SO	33	1	9	3	4	15	2	0	-
1823910	ENVIR CST UNDR AMORT	103466	Portland Harbor Service Ctr	SO	4,057	89	1,102	311	533	1,782	237	1	-
1823910	ENVIR CST UNDR AMORT	103467	Wyodak Fuel Oil Spill	SO	75	2	20	6	10	33	4	0	-
1823910	ENVIR CST UNDR AMORT	103585	CLINE FALLS-HYDRO	SO	38	1	10	3	5	17	2	0	-
1823910	ENVIR CST UNDR AMORT	103737	Geneva Rock Bldg - Hunter Plant	SO	12	0	3	1	2	5	1	0	-
1823910	ENVIR CST UNDR AMORT	103851	Alturas Service Center (CA)	SO	4	0	1	0	0	2	0	0	-
1823910	ENVIR CST UNDR AMORT	103852	Pendleton Service Center (OR)	SO	2	0	1	0	0	1	0	0	-
1823910	ENVIR CST UNDR AMORT	103853	Sunnyside Service Center (WA)	SO	0	0	0	0	0	0	0	0	-
1823910	ENVIR CST UNDR AMORT	103940	D-SM Retail Minor Sites - RMP - 2012	SO	62	1	17	5	8	27	4	0	-
1823910	ENVIR CST UNDR AMORT	103941	D-SM Retail Minor Sites - RMP - 2013	SO	147	3	40	11	19	65	9	0	-
1823910	ENVIR CST UNDR AMORT	103942	D-SM Retail Minor Sites - RMP - 2014	SO	336	7	91	26	44	148	20	0	-
1823910	ENVIR CST UNDR AMORT	103948	WASHINGTON NON-DEFERRED COSTS-SPPC PACIF	WA	(87)	-	-	(87)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103949	WASHINGTON NON-DEFERRED COSTS-SPPC ROCKY	WA	(69)	-	-	(69)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103950	WASHINGTON NON-DEFERRED COSTS-REMEDATIO	WA	(88)	-	-	(88)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103951	WASHINGTON NON-DEFERRED COSTS-REMEDATIO	WA	(360)	-	-	(360)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103952	WASHINGTON NON-DEFERRED COSTS-REMEDATIO	WA	(85)	-	-	(85)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103953	Wash Non-Def Costs - SPPC - RMP - 2012	WA	(24)	-	-	(24)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103954	Wash Non-Def Costs - SPPC - RMP - 2013	WA	(57)	-	-	(57)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103955	Wash Non-Def Costs - SPPC - RMP - 2014	WA	(152)	-	-	(152)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103961	D-SM RETAIL MINOR SITES - RMP	SO	3,319	73	902	255	436	1,458	194	1	-
1823910	ENVIR CST UNDR AMORT	104072	FREEPORT SUBSTATION	SO	54	1	15	4	7	24	3	0	-
1823910	ENVIR CST UNDR AMORT	104108	Bors Property (OR) - 2016	SO	13	0	4	1	2	6	1	0	-
1823910	ENVIR CST UNDR AMORT	104112	Carbon Ash Spill (UT) - 2016	SO	2,628	58	714	202	345	1,154	154	1	-
1823910	ENVIR CST UNDR AMORT	104144	Naughton Oil Spill	SO	16	0	4	1	2	7	1	0	-
1823910	ENVIR CST UNDR AMORT	104175	Ririe Substation	SO	8	0	2	1	1	3	0	0	-
1823910	ENVIR CST UNDR AMORT	104197	Bridger Plant - FGD Pond 1	SO	450	10	122	35	59	198	26	0	-
1823910	ENVIR CST UNDR AMORT	104198	Bridger Plant - FGD Pond 2	SO	21	0	6	2	3	9	1	0	-
1823910	ENVIR CST UNDR AMORT	104199	Naughton Plant - FGD Pond 1	SO	372	8	101	29	49	164	22	0	-
1823910	ENVIR CST UNDR AMORT	104200	Naughton Plant - FGD Pond 2	SO	691	15	188	53	91	303	40	0	-
1823910	ENVIR CST UNDR AMORT	104201	Huntington Plant Ash Landfill	SO	229	5	62	18	30	101	13	0	-
1823910	ENVIR CST UNDR AMORT	104202	Dave Johnston Pond 4A & 4B	SO	1,519	33	413	117	200	667	89	0	-
1823910	ENVIR CST UNDR AMORT	104203	Colstrip Pond	SO	1,543	34	419	118	203	678	90	0	-
1823910	ENVIR CST UNDR AMORT	104204	Cholla Ash-Flyash Pond	SO	39	1	11	3	5	17	2	0	-
1823910	ENVIR CST UNDR AMORT	104206	Naughton South Ash Pond	SO	61	1	17	5	8	27	4	0	-
1823910	ENVIR CST UNDR AMORT	104210	American Barrel (UT)-WA	WA	(14)	-	-	(14)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104211	Astoria/Unocal (Downtown)-WA	WA	(48)	-	-	(48)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104212	ASTORIA YOUNGS BAY CLEANUP-WA	WA	(8)	-	-	(8)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104213	Big Fork Hydro Plant (MT)-WA	WA	(9)	-	-	(9)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104214	Bors Property (OR) - WA	WA	(1)	-	-	(1)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104215	Bridger Coal Fuel Oil Spill - WA	WA	(22)	-	-	(22)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104216	Bridger FGD Pond 1 Closure-WA	WA	(21)	-	-	(21)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104218	Bridger Plant - FGD Pond 1-WA	WA	(34)	-	-	(34)	-	-	-	-	-
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	(12)	-	-	(12)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104221	Carbon Ash Spill (UT) - WA	WA	(46)	-	-	(46)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104222	Cedar Steam - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104223	Colstrip Pond - WA	WA	(105)	-	-	(105)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104224	Cholla Ash - WA	WA	(3)	-	-	(3)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104225	DJ Oil Spill - WA	WA	(8)	-	-	(8)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104226	DJ 4A&4B - WA	WA	(103)	-	-	(103)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104227	Eugene MGP (50%PCRP) - WA	WA	(17)	-	-	(17)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104228	Everett MGP (2/3 PCRP) - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104229	Hunter Plant - WA	WA	(21)	-	-	(21)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104230	Huntington Ash- WA	WA	(39)	-	-	(39)	-	-	-	-	-



**Regulatory Assessts (Actuals)**

Year End: 06/2021

Allocation Method - Factor 2020 Protocol

(Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other	
1823910	ENVIR CST UNDR AMORT	104231	Idaho Falls Pole Yard- WA	WA	(54)	-	-	(54)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104232	Jordan Plant Substation- WA	WA	(3)	-	-	(3)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104233	Montague Ranch - WA	WA	(0)	-	-	(0)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104234	Naughton Plant FGDP 1 - WA	WA	(26)	-	-	(26)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104235	Naughton Plant FGDP 2 - WA	WA	(47)	-	-	(47)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104236	Naughton Plant FGDP Closure - WA	WA	(4)	-	-	(4)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104237	Naughton Oil Spill - WA	WA	(0)	-	-	(0)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104239	Naughton South Ash Pond - WA	WA	(4)	-	-	(4)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104240	Ogden MGP - WA	WA	(72)	-	-	(72)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104241	Olympia - WA	WA	(0)	-	-	(0)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104242	Portland Harbor Srce Cntrl - WA	WA	(201)	-	-	(201)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104244	Silver Bell/Telluride - WA	WA	(174)	-	-	(174)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104245	Tacoma A St. (25% PCRP) - WA	WA	(2)	-	-	(2)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104246	Utah Metal East - WA	WA	(0)	-	-	(0)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104247	Wyodak Oil Spill - WA	WA	(3)	-	-	(3)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104248	Hunter Fuel Oil Spill-WA	WA	(0)	-	-	(0)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104268	Rocky Mountain - WA	WA	(154)	-	-	(154)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104269	Pac Power - WA	WA	(190)	-	-	(190)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104296	NTO Parking Lot-Asbestos 2018	SO	162	4	44	12	21	71	9	
1823910	ENVIR CST UNDR AMORT	104297	NTO Parking Lot Asbestos - WA 2018	WA	(12)	-	-	(12)	-	-	-	
1823910	ENVIR CST UNDR AMORT	104394	Klamath Falls	SO	431	10	117	33	57	190	25	
1823910	ENVIR CST UNDR AMORT	104399	Portland Harbor Service Insurance	SO	(890)	(20)	(242)	(68)	(117)	(391)	(52)	
<b>1823910</b>	<b>Total</b>				<b>32,180</b>	<b>763</b>	<b>9,402</b>	<b>236</b>	<b>4,549</b>	<b>15,202</b>	<b>2,021</b>	<b>7</b>
1823920	DSR COSTS AMORTIZED	0	DSR COST AMORT	OTHER	273,786	-	-	-	-	-	-	273,786
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
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



Regulatory Assessts (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
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



**Regulatory Assessts (Actuals)**

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(Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
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



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Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
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
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



**Regulatory Assests (Actuals)**

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(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
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
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





**Regulatory Assessts (Actuals)**

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(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
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	AGRICULTURAL 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
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	AGRICULTURAL FINANSWER EXP WY-2012 CAT2	OTHER	1	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103366	AGRICULTURAL 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



**Regulatory Assests (Actuals)**

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(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
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
1823920	DSR COSTS AMORTIZED	103693	AGRICULTURAL 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	AGRICULTURAL 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



**Regulatory Assests (Actuals)**

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(Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
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	AGRICULTURAL FINANSWER EXP WY-2014 CAT2	OTHER	4	-	-	-	-	-	4
1823920	DSR COSTS AMORTIZED	103780	AGRICULTURAL 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-2	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
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



**Regulatory Assessts (Actuals)**

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(Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
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	AGRICULTURAL 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-2	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



**Regulatory Assessts (Actuals)**

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(Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	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



**Regulatory Assests (Actuals)**

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(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823920	DSR COSTS AMORTIZED	104111	WY DSM - 186065 Clear Acct Balance	OTHER	(1,405)	-	-	-	-	-	-	(1,405)
<b>1823920</b>	<b>Total</b>				<b>233,130</b>	-	-	-	-	-	-	<b>233,130</b>
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-RESIDL/ID-UT 2006	OTHER	2	-	-	-	-	-	-	2
1823930	DSR COSTS NOT AMORT	102579	REFRIGERATOR RECYCLING PGM-ID-UT 2006	OTHER	143	-	-	-	-	-	-	143
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



**Regulatory Assests (Actuals)**

Year End: 06/2021

Allocation Method - Factor 2020 Protocol

(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
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
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	AGRICULTURAL 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	AGRICULTURAL 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	AGRICULTURAL 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	AGRICULTURAL 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



**Regulatory Assests (Actuals)**

Year End: 06/2021

Allocation Method - Factor 2020 Protocol

(Allocated in Thousands)

Primary Account	Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
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
<b>1823930 Total</b>					<b>37,937</b>	-	-	-	-	-	-	<b>37,937</b>
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)
<b>1823940 Total</b>					<b>2,719</b>	-	-	-	-	-	-	<b>2,719</b>
1823990	OTHR REG ASSET-N CST	138014	Reg Asset Current - Cholla Closure	OTHER	2,681	-	-	-	-	-	-	2,681
1823990	OTHR REG ASSET-N CST	138015	Reg Asset Current - Energy West Mining	SE	1,836	26	460	135	283	812	118	1
1823990	OTHR REG ASSET-N CST	138020	Reg Asset Current - DSM	OTHER	17,428	-	-	-	-	-	-	17,428
1823990	OTHR REG ASSET-N CST	138045	Reg Asset Current - GHG Allowances	OTHER	222	-	-	-	-	-	-	222
1823990	OTHR REG ASSET-N CST	138050	Reg Asset Current - Def Net Power Costs	OTHER	39,407	-	-	-	-	-	-	39,407
1823990	OTHR REG ASSET-N CST	138055	Reg Asset Current - Def RECs in Rates	OTHER	100	-	-	-	-	-	-	100
1823990	OTHR REG ASSET-N CST	138060	Reg Asset Current - BPA Balancing Accts	OTHER	6,849	-	-	-	-	-	-	6,849
1823990	OTHR REG ASSET-N CST	138090	Reg Asset Current - Solar Feed-In	OTHER	7,034	-	-	-	-	-	-	7,034
1823990	OTHR REG ASSET-N CST	138190	Reg Asset Current - Other	OTHER	10,111	-	-	-	-	-	-	10,111
1823990	OTHR REG ASSET-N CST	185879	Reg A - Cholla Closure - Recl to Curr	OTHER	(2,681)	-	-	-	-	-	-	(2,681)
1823990	OTHR REG ASSET-N CST	186100	Calif Alternative Rate for Energy (CARE)	OTHER	(433)	-	-	-	-	-	-	(433)
1823990	OTHR REG ASSET-N CST	186117	RegA - DSM - CA - Reclass to Current	OTHER	(18)	-	-	-	-	-	-	(18)
1823990	OTHR REG ASSET-N CST	186127	RegA - DSM - ID - Reclass to Current	OTHER	(4)	-	-	-	-	-	-	(4)
1823990	OTHR REG ASSET-N CST	186137	RegA - DSM - OR - Reclass to Current	OTHER	(266)	-	-	-	-	-	-	(266)
1823990	OTHR REG ASSET-N CST	186147	RegA - DSM - UT - Reclass to Current	OTHER	(17,140)	-	-	-	-	-	-	(17,140)
1823990	OTHR REG ASSET-N CST	186159	Reg Asset - DSM - WA - Balance Reclass	OTHER	4,027	-	-	-	-	-	-	4,027
1823990	OTHR REG ASSET-N CST	186502	POWERDALE HYDRO DECOM REG ASSET - ID	IDU	6	-	-	-	-	6	-	-
1823990	OTHR REG ASSET-N CST	186793	RegA - Deer Creek - OR - Recl to Curr	SE	(1,091)	(15)	(273)	(80)	(168)	(483)	(70)	(0)
1823990	OTHR REG ASSET-N CST	187042	Reg Asset - CA GHG Allowances	OTHER	(527)	-	-	-	-	-	-	(527)
1823990	OTHR REG ASSET-N CST	187048	RegA - CA GHG Allowances - Recl to Curr	OTHER	(222)	-	-	-	-	-	-	(222)
1823990	OTHR REG ASSET-N CST	187049	RegA - CA GHG Allowances - Balance Recl	OTHER	749	-	-	-	-	-	-	749
1823990	OTHR REG ASSET-N CST	187191	Reg Asset - WA RPS Purchase	OTHER	126	-	-	-	-	-	-	126
1823990	OTHR REG ASSET-N CST	187230	RegA - Oregon OCAT Expense Deferral	OTHER	1,230	-	-	-	-	-	-	1,230
1823990	OTHR REG ASSET-N CST	187255	RegA - BPA Balancing Accts - Recl to Cur	OTHER	(6,849)	-	-	-	-	-	-	(6,849)
1823990	OTHR REG ASSET-N CST	187300	CA - Jan 2010 Storm Costs	OTHER	(85)	-	-	-	-	-	-	(85)
1823990	OTHR REG ASSET-N CST	187301	Reg Asset - CA - CEMA Costs Deferral	OTHER	477	-	-	-	-	-	-	477
1823990	OTHR REG ASSET-N CST	187304	RegA-CA Emerg Svc Prgms-Battery Storage	OTHER	(619)	-	-	-	-	-	-	(619)
1823990	OTHR REG ASSET-N CST	187305	RegA - ID 2017 Protocol - MSP Deferral	IDU	300	-	-	-	-	300	-	-
1823990	OTHR REG ASSET-N CST	187311	Contra Reg Asset-Carbon Plt Dec/Inv-CA	CA	(52)	(52)	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187312	Contra Reg Asset-Carbon Plt Dec/Inv-WY	WYP	(523)	-	-	-	(523)	-	-	-
1823990	OTHR REG ASSET-N CST	187320	Reg Asset - Deprec Increase - ID	IDU	5,947	-	-	-	-	5,947	-	-
1823990	OTHR REG ASSET-N CST	187321	Reg Asset - Deprec Increase - UT	UT	1,280	-	-	-	-	1,280	-	-
1823990	OTHR REG ASSET-N CST	187322	Reg Asset - Deprec Increase - WY	WYP	16,226	-	-	-	16,226	-	-	-
1823990	OTHR REG ASSET-N CST	187332	Reg Asset - Carbon Unrec Plant - UT	UT	2,426	-	-	-	2,426	-	-	-
1823990	OTHR REG ASSET-N CST	187337	Reg Asset - Carbon Decomm - CA	CA	548	548	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	CA	(1,517)	(1,517)	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	OR	(90)	-	(90)	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	SG	3,449	51	899	270	489	1,531	207	1
1823990	OTHR REG ASSET-N CST	187345	Reg Asset - UT - Pref Stock Redemp Loss	OTHER	224	-	-	-	-	-	-	224
1823990	OTHR REG ASSET-N CST	187346	Reg Asset - WY - Pref Stock Redemp Loss	OTHER	77	-	-	-	-	-	-	77
1823990	OTHR REG ASSET-N CST	187347	Reg Asset - WA - Pref Stock Redemp Loss	OTHER	36	-	-	-	-	-	-	36
1823990	OTHR REG ASSET-N CST	187350	ID - Deferred Overburden Costs	OTHER	468	-	-	-	-	-	-	468
1823990	OTHR REG ASSET-N CST	187351	WY - Deferred Overburden Costs	WYP	1,318	-	-	-	1,318	-	-	-
1823990	OTHR REG ASSET-N CST	187354	RegA-OR 2020 GRC-Meters Replcd by AMI	OTHER	15,455	-	-	-	-	-	-	15,455





**Regulatory Assests (Actuals)**

Year End: 06/2021

Allocation Method - Factor 2020 Protocol

(Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other	
1823990	OTHR REG ASSET-N CST	187357	CA Mobile Home Park Conversion (MHPCBA)	OTHER	218	-	-	-	-	-	218	
1823990	OTHR REG ASSET-N CST	187361	Reg A-OR-COVID-19 Bill Assistance Prog	OTHER	4,635	-	-	-	-	-	4,635	
1823990	OTHR REG ASSET-N CST	187362	Reg A-WA-COVID-19 Bill Assistance Prog	OTHER	1,475	-	-	-	-	-	1,475	
1823990	OTHR REG ASSET-N CST	187380	Reg Asset - UT Solar Incentive Program	OTHER	(2,086)	-	-	-	-	-	(2,086)	
1823990	OTHR REG ASSET-N CST	187382	Reg Asset-OR Solar Feed-In Tariff 2020	OTHER	2,289	-	-	-	-	-	2,289	
1823990	OTHR REG ASSET-N CST	187383	RegA - OR Solar Feed-In - Recl to Curr	OTHER	(6,908)	-	-	-	-	-	(6,908)	
1823990	OTHR REG ASSET-N CST	187384	RegA - UT Solar Feed-In - Recl to Curr	OTHER	(125)	-	-	-	-	-	(125)	
1823990	OTHR REG ASSET-N CST	187386	Reg Asset-OR Solar Feed-In Tariff 2021	OTHER	3,068	-	-	-	-	-	3,068	
1823990	OTHR REG ASSET-N CST	187387	Reg Asset-Utah STEP Pilot Prog Bal Acct	OTHER	(17,819)	-	-	-	-	-	(17,819)	
1823990	OTHR REG ASSET-N CST	187390	UT-Klamath Hydro Relicensing Costs	OTHER	6,173	-	-	-	-	-	6,173	
1823990	OTHR REG ASSET-N CST	187394	RegA - UT Solar Feed-In - Recl to Liab	OTHER	19,905	-	-	-	-	-	19,905	
1823990	OTHR REG ASSET-N CST	187415	Reg Asset-UT Subscriber Solar Program	OTHER	1,940	-	-	-	-	-	1,940	
1823990	OTHR REG ASSET-N CST	187420	RegA - OR Community Solar	OTHER	1,551	-	-	-	-	-	1,551	
1823990	OTHR REG ASSET-N CST	187488	RegA-WA Decoupling Mech - Recl to Curr	OTHER	(4,033)	-	-	-	-	-	(4,033)	
1823990	OTHR REG ASSET-N CST	187489	Reg A-WA Decoupling Mechanism-Reclass	OTHER	4,033	-	-	-	-	-	4,033	
1823990	OTHR REG ASSET-N CST	187495	RegA - Other - Recl to Curr	OTHER	(6,075)	-	-	-	-	-	(6,075)	
1823990	OTHR REG ASSET-N CST	187648	Reg A - Post-Retirement - Recl to Curr	SE	(745)	(11)	(187)	(55)	(115)	(330)	(48)	(0)
1823990	OTHR REG ASSET-N CST	187660	RegA-OR Transp Electrification Pilot	OTHER	3,675	-	-	-	-	-	3,675	
1823990	OTHR REG ASSET-N CST	187662	RegA-CA Transp Electrification Pilot	OTHER	(229)	-	-	-	-	-	(229)	
1823990	OTHR REG ASSET-N CST	187664	RegA-WA Transp Electrification Pilot	OTHER	397	-	-	-	-	-	397	
1823990	OTHR REG ASSET-N CST	187830	Reg Asset - UT RBA CY2021	OTHER	(1,170)	-	-	-	-	-	(1,170)	
1823990	OTHR REG ASSET-N CST	187859	Reg Asset - WY ECAM CY2019	OTHER	2,169	-	-	-	-	-	2,169	
1823990	OTHR REG ASSET-N CST	187869	Reg Asset - WY RRA CY2019	OTHER	(45)	-	-	-	-	-	(45)	
1823990	OTHR REG ASSET-N CST	187879	Contra Reg Asset - WY ECAM CY2019	OTHER	(743)	-	-	-	-	-	(743)	
1823990	OTHR REG ASSET-N CST	187880	Reg Asset - UT RBA CY2019	OTHER	(28)	-	-	-	-	-	(28)	
1823990	OTHR REG ASSET-N CST	187882	Reg Asset - UT RBA CY2020	OTHER	(748)	-	-	-	-	-	(748)	
1823990	OTHR REG ASSET-N CST	187884	Reg Asset - WY RRA CY2020	OTHER	(49)	-	-	-	-	-	(49)	
1823990	OTHR REG ASSET-N CST	187885	Reg Asset - WY RRA CY2021	OTHER	(640)	-	-	-	-	-	(640)	
1823990	OTHR REG ASSET-N CST	187886	Reg Asset-OR RPS Compliance Purchases	OTHER	(222)	-	-	-	-	-	(222)	
1823990	OTHR REG ASSET-N CST	187888	RegA - WA RECs in Rates - Recl to Curr	OTHER	(100)	-	-	-	-	-	(100)	
1823990	OTHR REG ASSET-N CST	187895	RegA - OR RECs in Rates - Balance Recl	OTHER	222	-	-	-	-	-	222	
1823990	OTHR REG ASSET-N CST	187897	RegA - UT RECs in Rates - Recl to Liab	OTHER	1,946	-	-	-	-	-	1,946	
1823990	OTHR REG ASSET-N CST	187899	RegA - WY RECs in Rates - Recl to Liab	OTHER	733	-	-	-	-	-	733	
1823990	OTHR REG ASSET-N CST	187911	REG ASSET - LAKE SIDE LIQ. DAMAGES - WY	WYP	717	-	-	-	717	-	-	
1823990	OTHR REG ASSET-N CST	187913	Reg Asset - Goodnoe Hills Liq. Damages -	WYP	266	-	-	-	266	-	-	
1823990	OTHR REG ASSET-N CST	187914	"Reg Asset-UT-Liq. Damages JB4, N1&2"	UT	437	-	-	-	-	437	-	
1823990	OTHR REG ASSET-N CST	187915	Reg Asset-WY-Liq. Damages N2	WYP	71	-	-	-	71	-	-	
1823990	OTHR REG ASSET-N CST	187952	DEFERRED INTERVENOR	OTHER	0	-	-	-	-	-	0	
1823990	OTHR REG ASSET-N CST	187956	CA DEFERRED INTERVENOR FUNDING	OTHER	152	-	-	-	-	-	152	
1823990	OTHR REG ASSET-N CST	187957	DEFERRED OR INDEPENDENT EVALUATOR FEES	OTHER	38	-	-	-	-	-	38	
1823990	OTHR REG ASSET-N CST	187958	ID Deferred Intervenor Funding	IDU	103	-	-	-	-	103	-	
1823990	OTHR REG ASSET-N CST	187964	RegA - Intervenor Fees - Recl to Liab	OTHER	639	-	-	-	-	-	639	
1823990	OTHR REG ASSET-N CST	187966	RegA - CA (CARE) Program - Recl to Liab	OTHER	433	-	-	-	-	-	433	
1823990	OTHR REG ASSET-N CST	187967	RegA - OR Asset Sale Gain-Balance Recl	OTHER	2,124	-	-	-	-	-	2,124	
1823990	OTHR REG ASSET-N CST	187968	Reg A - Insurance Reserves - Reclass	OTHER	20,938	-	-	-	-	-	20,938	
1823990	OTHR REG ASSET-N CST	187975	Reg Asset - CA ECAC	OTHER	(481)	-	-	-	-	-	(481)	
1823990	OTHR REG ASSET-N CST	187979	Contra Reg Asset - CA ECAC CY2018	OTHER	(212)	-	-	-	-	-	(212)	
1823990	OTHR REG ASSET-N CST	189001	RegA-CA Fire Risk Mitigation (FRMMA)	OTHER	3	-	-	-	-	-	3	
1823990	OTHR REG ASSET-N CST	189002	RegA-CA Wildfire Mitigation Plan(WMPMA)	OTHER	14,852	-	-	-	-	-	14,852	
1823990	OTHR REG ASSET-N CST	189003	Contra RegA-CA Fire/Wildlife Mitigation	OTHER	(900)	-	-	-	-	-	(900)	
1823990	OTHR REG ASSET-N CST	189004	RegA-CA Fire Hazard Prevention (FHPMA)	OTHER	3,157	-	-	-	-	-	3,157	
1823990	OTHR REG ASSET-N CST	189500	Reg Asset - CA ECAC CY2019	OTHER	1,840	-	-	-	-	-	1,840	
1823990	OTHR REG ASSET-N CST	189501	Contra Reg Asset - CA ECAC CY2019	OTHER	(134)	-	-	-	-	-	(134)	
1823990	OTHR REG ASSET-N CST	189502	Reg Asset - CA ECAC CY2020	OTHER	(841)	-	-	-	-	-	(841)	



Regulatory Assests (Actuals)  
 Year End: 06/2021  
 Allocation Method - Factor 2020 Protocol  
 (Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other		
1823990	OTHR REG ASSET-N CST	189503	Contra Reg Asset - CA ECAC CY2020	OTHER	(45)	-	-	-	-	-	(45)		
1823990	OTHR REG ASSET-N CST	189504	Reg Asset - CA ECAC CY2021	OTHER	(80)	-	-	-	-	-	(80)		
1823990	OTHR REG ASSET-N CST	189505	Contra Reg Asset - CA ECAC CY2021	OTHER	(9)	-	-	-	-	-	(9)		
1823990	OTHR REG ASSET-N CST	189506	Reg Asset - CA ECAC CY2022	OTHER	2	-	-	-	-	-	2		
1823990	OTHR REG ASSET-N CST	189507	Contra Reg Asset - CA ECAC CY2022	OTHER	(0)	-	-	-	-	-	(0)		
1823990	OTHR REG ASSET-N CST	189528	RegA - CA Def Exc NPC - Recl to Curr	OTHER	(569)	-	-	-	-	-	(569)		
1823990	OTHR REG ASSET-N CST	189529	RegA - CA Def Exc NPC - Recl to Liab	OTHER	529	-	-	-	-	-	529		
1823990	OTHR REG ASSET-N CST	189535	Reg Asset-ID ECAM CY 2020	OTHER	8,216	-	-	-	-	-	8,216		
1823990	OTHR REG ASSET-N CST	189536	Reg Asset-ID ECAM CY 2021	OTHER	13,513	-	-	-	-	-	13,513		
1823990	OTHR REG ASSET-N CST	189537	Reg Asset-ID ECAM CY 2022	OTHER	12	-	-	-	-	-	12		
1823990	OTHR REG ASSET-N CST	189546	Contra Reg Asset - ID ECAM CY 2021	OTHER	(676)	-	-	-	-	-	(676)		
1823990	OTHR REG ASSET-N CST	189547	Contra Reg Asset - ID ECAM CY 2022	OTHER	(1)	-	-	-	-	-	(1)		
1823990	OTHR REG ASSET-N CST	189568	RegA - ID Def Exc NPC - Recl to Curr	OTHER	(9,286)	-	-	-	-	-	(9,286)		
1823990	OTHR REG ASSET-N CST	189571	Reg Asset - OR TAM CY2021	OTHER	800	-	-	-	-	-	800		
1823990	OTHR REG ASSET-N CST	189572	Reg Asset-OR TAM CY 2022	OTHER	47	-	-	-	-	-	47		
1823990	OTHR REG ASSET-N CST	189582	Contra Reg Asset - OR TAM CY 2022	OTHER	(2)	-	-	-	-	-	(2)		
1823990	OTHR REG ASSET-N CST	189598	RegA - OR Def Exc NPC - Recl to Curr	OTHER	(822)	-	-	-	-	-	(822)		
1823990	OTHR REG ASSET-N CST	189609	Reg Asset - UT EBA CY2019	OTHER	28,286	-	-	-	-	-	28,286		
1823990	OTHR REG ASSET-N CST	189610	Reg Asset - UT EBA CY2020	OTHER	1,871	-	-	-	-	-	1,871		
1823990	OTHR REG ASSET-N CST	189611	Reg Asset - UT EBA CY2021	OTHER	48,902	-	-	-	-	-	48,902		
1823990	OTHR REG ASSET-N CST	189612	Reg Asset - UT EBA CY2022	OTHER	86	-	-	-	-	-	86		
1823990	OTHR REG ASSET-N CST	189620	Contra Reg Asset - UT EBA CY2020	OTHER	(93)	-	-	-	-	-	(93)		
1823990	OTHR REG ASSET-N CST	189621	Contra Reg Asset - UT EBA CY2021	OTHER	(2,696)	-	-	-	-	-	(2,696)		
1823990	OTHR REG ASSET-N CST	189622	Contra Reg Asset - UT EBA CY2022	OTHER	(4)	-	-	-	-	-	(4)		
1823990	OTHR REG ASSET-N CST	189638	RegA - UT Def Exc NPC - Recl to Curr	OTHER	(28,730)	-	-	-	-	-	(28,730)		
1823990	OTHR REG ASSET-N CST	189642	Reg Asset-WA-Major Mtc Exp-Colstrip U4	WA	259	-	259	-	-	-	-		
1823990	OTHR REG ASSET-N CST	189650	Reg Asset - WY ECAM CY2020	OTHER	(2,277)	-	-	-	-	-	(2,277)		
1823990	OTHR REG ASSET-N CST	189651	Reg Asset - WY ECAM CY2021	OTHER	7,905	-	-	-	-	-	7,905		
1823990	OTHR REG ASSET-N CST	189652	Reg Asset - WY ECAM CY2022	OTHER	23	-	-	-	-	-	23		
1823990	OTHR REG ASSET-N CST	189660	Contra Reg Asset - WY ECAM CY2020	OTHER	121	-	-	-	-	-	121		
1823990	OTHR REG ASSET-N CST	189661	Contra Reg Asset - WY ECAM CY2021	OTHER	339	-	-	-	-	-	339		
1823990	OTHR REG ASSET-N CST	189662	Contra Reg Asset - WY ECAM CY2022	OTHER	(1)	-	-	-	-	-	(1)		
1823990	OTHR REG ASSET-N CST	189689	RegA - WY Def Exc NPC - Recl to Liab	OTHER	43	-	-	-	-	-	43		
<b>1823990 Total</b>					<b>229,448</b>	<b>(971)</b>	<b>809</b>	<b>529</b>	<b>18,565</b>	<b>5,675</b>	<b>6,563</b>	<b>1</b>	<b>198,277</b>
1823999	REGULATORY ASST-OTH	186011	DSM Reg Asset - Accruals - CA	OTHER	224	-	-	-	-	-	224		
1823999	REGULATORY ASST-OTH	186015	DSM Reg Asset - Balancing Acct - CA	OTHER	(207)	-	-	-	-	-	(207)		
1823999	REGULATORY ASST-OTH	186021	DSM Reg Asset - Accruals - ID	OTHER	242	-	-	-	-	-	242		
1823999	REGULATORY ASST-OTH	186025	DSM Reg Asset - Balancing Acct - ID	OTHER	(238)	-	-	-	-	-	(238)		
1823999	REGULATORY ASST-OTH	186035	DSM Reg Asset - Balancing Acct - OR	OTHER	266	-	-	-	-	-	266		
1823999	REGULATORY ASST-OTH	186041	DSM Reg Asset - Accruals - UT	OTHER	3,110	-	-	-	-	-	3,110		
1823999	REGULATORY ASST-OTH	186045	DSM Reg Asset - Balancing Acct - UT	OTHER	(11,086)	-	-	-	-	-	(11,086)		
1823999	REGULATORY ASST-OTH	186051	DSM Reg Asset - Accruals - WA	OTHER	761	-	-	-	-	-	761		
1823999	REGULATORY ASST-OTH	186055	DSM Reg Asset - Balancing Acct - WA	OTHER	(4,787)	-	-	-	-	-	(4,787)		
1823999	REGULATORY ASST-OTH	186061	DSM Reg Asset - Accruals - WY	OTHER	331	-	-	-	-	-	331		
1823999	REGULATORY ASST-OTH	186065	DSM Reg Asset - Balancing Acct - WY	OTHER	(2,521)	-	-	-	-	-	(2,521)		
1823999	REGULATORY ASST-OTH	186071	DSM Reg Asset - Accruals - WY Cat 1	OTHER	136	-	-	-	-	-	136		
1823999	REGULATORY ASST-OTH	186075	DSM Reg Asset-Balancing Acct-WY Cat 1	OTHER	325	-	-	-	-	-	325		
1823999	REGULATORY ASST-OTH	186081	DSM Reg Asset - Accruals - WY Cat 2	OTHER	62	-	-	-	-	-	62		
1823999	REGULATORY ASST-OTH	186085	DSM Reg Asset-Balancing Acct-WY Cat 2	OTHER	(4,763)	-	-	-	-	-	(4,763)		
<b>1823999 Total</b>					<b>(18,143)</b>								<b>(18,143)</b>
<b>Grand Total</b>					<b>1,045,178</b>	<b>14,891</b>	<b>163,973</b>	<b>42,609</b>	<b>136,349</b>	<b>263,385</b>	<b>41,137</b>	<b>163</b>	<b>382,670</b>

# **B17.DEPRECIATION RESERVE**



Depreciation Reserve (Actuals)  
 Year End: 06/2021  
 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	(27,448)	(403)	(7,156)	(2,152)	(3,896)	(12,185)	(1,648)	(8)	-
1080000	AC PR DPR EL PL SR 3103000	WATER RIGHTS	SG	(14,473)	(212)	(3,773)	(1,135)	(2,054)	(6,425)	(869)	(4)	-
1080000	AC PR DPR EL PL SR 3110000	STRUCTURES AND IMPROVEMENTS	SG	(555,552)	(8,152)	(144,834)	(43,549)	(78,851)	(246,637)	(33,366)	(163)	-
1080000	AC PR DPR EL PL SR 3120000	BOILER PLANT EQUIPMENT	SG	(2,082,185)	(30,552)	(542,833)	(163,221)	(295,531)	(924,385)	(125,054)	(609)	-
1080000	AC PR DPR EL PL SR 3140000	TURBOGENERATOR UNITS	SG	(456,755)	(6,702)	(119,078)	(35,805)	(64,829)	(202,776)	(27,432)	(134)	-
1080000	AC PR DPR EL PL SR 3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	(237,785)	(3,489)	(61,991)	(18,640)	(33,750)	(105,564)	(14,281)	(70)	-
1080000	AC PR DPR EL PL SR 3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	(33)	(0)	(9)	(3)	(5)	(15)	(2)	(0)	-
1080000	AC PR DPR EL PL SR 3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	(15,280)	(224)	(3,983)	(1,198)	(2,169)	(6,783)	(918)	(4)	-
1080000	AC PR DPR EL PL SR 3302000	LAND RIGHTS	SG-P	(4,037)	(59)	(1,053)	(316)	(573)	(1,792)	(242)	(1)	-
1080000	AC PR DPR EL PL SR 3302000	LAND RIGHTS	SG-U	(139)	(2)	(36)	(11)	(20)	(62)	(8)	(0)	-
1080000	AC PR DPR EL PL SR 3303000	WATER RIGHTS	SG-P	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
1080000	AC PR DPR EL PL SR 3303000	WATER RIGHTS	SG-U	(102)	(1)	(27)	(8)	(14)	(45)	(6)	(0)	-
1080000	AC PR DPR EL PL SR 3304000	FLOOD RIGHTS	SG-P	(285)	(4)	(74)	(22)	(40)	(126)	(17)	(0)	-
1080000	AC PR DPR EL PL SR 3304000	FLOOD RIGHTS	SG-U	(93)	(1)	(24)	(7)	(13)	(41)	(6)	(0)	-
1080000	AC PR DPR EL PL SR 3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	(155)	(2)	(40)	(12)	(22)	(69)	(9)	(0)	-
1080000	AC PR DPR EL PL SR 3310000	STRUCTURES AND IMPROVE	SG-P	(29)	(0)	(8)	(2)	(4)	(13)	(2)	(0)	-
1080000	AC PR DPR EL PL SR 3310000	STRUCTURES AND IMPROVE	SG-U	(5,564)	(82)	(1,451)	(436)	(790)	(2,470)	(334)	(2)	-
1080000	AC PR DPR EL PL SR 3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	(33,764)	(495)	(8,802)	(2,647)	(4,792)	(14,990)	(2,028)	(10)	-
1080000	AC PR DPR EL PL SR 3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	(2,521)	(37)	(657)	(198)	(358)	(1,119)	(151)	(1)	-
1080000	AC PR DPR EL PL SR 3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	(34,182)	(502)	(8,911)	(2,680)	(4,852)	(15,175)	(2,053)	(10)	-
1080000	AC PR DPR EL PL SR 3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	(243)	(4)	(63)	(19)	(34)	(108)	(15)	(0)	-
1080000	AC PR DPR EL PL SR 3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	(7,653)	(112)	(1,995)	(600)	(1,086)	(3,397)	(460)	(2)	-
1080000	AC PR DPR EL PL SR 3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	(1,208)	(18)	(315)	(95)	(171)	(536)	(73)	(0)	-
1080000	AC PR DPR EL PL SR 3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	(1,648)	(24)	(430)	(129)	(234)	(732)	(99)	(0)	-
1080000	AC PR DPR EL PL SR 3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	(18,728)	(275)	(4,883)	(1,468)	(2,658)	(8,314)	(1,125)	(5)	-
1080000	AC PR DPR EL PL SR 3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	(200,863)	(2,947)	(52,366)	(15,746)	(28,509)	(89,173)	(12,064)	(59)	-
1080000	AC PR DPR EL PL SR 3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	(33,978)	(499)	(8,858)	(2,664)	(4,823)	(15,084)	(2,041)	(10)	-
1080000	AC PR DPR EL PL SR 3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	(10,146)	(149)	(2,645)	(795)	(1,440)	(4,504)	(609)	(3)	-
1080000	AC PR DPR EL PL SR 3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	(302)	(4)	(79)	(24)	(43)	(134)	(18)	(0)	-
1080000	AC PR DPR EL PL SR 3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	(76)	(1)	(20)	(6)	(11)	(34)	(5)	(0)	-
1080000	AC PR DPR EL PL SR 3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	(51)	(1)	(13)	(4)	(7)	(22)	(3)	(0)	-
1080000	AC PR DPR EL PL SR 3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	(53,190)	(780)	(13,867)	(4,170)	(7,549)	(23,614)	(3,195)	(16)	-
1080000	AC PR DPR EL PL SR 3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	(21,932)	(322)	(5,718)	(1,719)	(3,113)	(9,737)	(1,317)	(6)	-
1080000	AC PR DPR EL PL SR 3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	(35,244)	(517)	(9,188)	(2,763)	(5,002)	(15,646)	(2,117)	(10)	-
1080000	AC PR DPR EL PL SR 3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	(7,354)	(108)	(1,917)	(576)	(1,044)	(3,265)	(442)	(2)	-
1080000	AC PR DPR EL PL SR 3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	(2,765)	(41)	(721)	(217)	(393)	(1,228)	(166)	(1)	-
1080000	AC PR DPR EL PL SR 3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	(15)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
1080000	AC PR DPR EL PL SR 3350000	MISC POWER PLANT EQUIP	SG-U	(122)	(2)	(32)	(10)	(17)	(54)	(7)	(0)	-
1080000	AC PR DPR EL PL SR 3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	(1,419)	(21)	(370)	(111)	(201)	(630)	(85)	(0)	-
1080000	AC PR DPR EL PL SR 3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	(10,459)	(153)	(2,727)	(820)	(1,484)	(4,643)	(628)	(3)	-
1080000	AC PR DPR EL PL SR 3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	(1,242)	(18)	(324)	(97)	(176)	(551)	(75)	(0)	-
1080000	AC PR DPR EL PL SR 3402000	LAND RIGHTS	SG	11,909	175	3,105	934	1,690	5,287	715	3	-
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	(17,540)	(257)	(4,573)	(1,375)	(2,489)	(7,787)	(1,053)	(5)	-
1080000	AC PR DPR EL PL SR 3410000	STRUCTURES & IMPROVEMENTS	UT	(1)	-	-	-	-	(1)	-	-	-
1080000	AC PR DPR EL PL SR 3420000	"FUEL HOLDERS, PRODUCERS, ACCES"	SG	(4,332)	(64)	(1,129)	(340)	(615)	(1,923)	(260)	(1)	-
1080000	AC PR DPR EL PL SR 3430000	PRIME MOVERS	SG	(15,985)	(235)	(4,167)	(1,253)	(2,269)	(7,096)	(960)	(5)	-
1080000	AC PR DPR EL PL SR 3440000	GENERATORS	SG	(93,142)	(1,367)	(24,282)	(7,301)	(13,220)	(41,350)	(5,594)	(27)	-
1080000	AC PR DPR EL PL SR 3440000	GENERATORS	UT	(3)	-	-	-	-	(3)	-	-	-
1080000	AC PR DPR EL PL SR 3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	(4,174)	(61)	(1,088)	(327)	(592)	(1,853)	(251)	(1)	-
1080000	AC PR DPR EL PL SR 3450000	ACCESSORY ELECTRIC EQUIPMENT	UT	(1)	-	-	-	-	(1)	-	-	-
1080000	AC PR DPR EL PL SR 3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	(1,856)	(27)	(484)	(146)	(263)	(824)	(111)	(1)	-
1080000	AC PR DPR EL PL SR 3502000	LAND RIGHTS	SG	(46,952)	(689)	(12,241)	(3,681)	(6,664)	(20,844)	(2,820)	(14)	-
1080000	AC PR DPR EL PL SR 3520000	STRUCTURES & IMPROVEMENTS	SG	(56,525)	(829)	(14,736)	(4,431)	(8,023)	(25,094)	(3,395)	(17)	-
1080000	AC PR DPR EL PL SR 3530000	STATION EQUIPMENT	SG	(525,132)	(7,705)	(136,904)	(41,165)	(74,534)	(233,132)	(31,539)	(154)	-
1080000	AC PR DPR EL PL SR 3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	(42,709)	(627)	(11,134)	(3,348)	(6,062)	(18,961)	(2,565)	(12)	-
1080000	AC PR DPR EL PL SR 3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	(6,424)	(94)	(1,675)	(504)	(912)	(2,852)	(386)	(2)	-
1080000	AC PR DPR EL PL SR 3540000	TOWERS AND FIXTURES	SG	(382,998)	(5,620)	(99,849)	(30,023)	(54,360)	(170,032)	(23,003)	(112)	-
1080000	AC PR DPR EL PL SR 3550000	POLES AND FIXTURES	SG	(420,047)	(6,163)	(109,508)	(32,927)	(59,619)	(186,479)	(25,228)	(123)	-
1080000	AC PR DPR EL PL SR 3560000	OVERHEAD CONDUCTORS & DEVICES	SG	(515,770)	(7,568)	(134,463)	(40,431)	(73,205)	(228,976)	(30,977)	(151)	-
1080000	AC PR DPR EL PL SR 3570000	UNDERGROUND CONDUIT	SG	(1,356)	(20)	(353)	(106)	(192)	(602)	(81)	(0)	-
1080000	AC PR DPR EL PL SR 3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	(3,312)	(49)	(863)	(260)	(470)	(1,470)	(199)	(1)	-
1080000	AC PR DPR EL PL SR 3590000	ROADS AND TRAILS	SG	(5,205)	(76)	(1,357)	(408)	(739)	(2,311)	(313)	(2)	-
1080000	AC PR DPR EL PL SR 3602000	LAND RIGHTS	CA	(798)	(798)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3602000	LAND RIGHTS	IDU	(516)	-	-	-	-	(516)	-	-	-
1080000	AC PR DPR EL PL SR 3602000	LAND RIGHTS	OR	(2,431)	-	(2,431)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3602000	LAND RIGHTS	UT	(3,241)	-	-	-	-	(3,241)	-	-	-
1080000	AC PR DPR EL PL SR 3602000	LAND RIGHTS	WA	(200)	-	-	(200)	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3602000	LAND RIGHTS	WYP	(1,509)	-	-	-	(1,509)	-	-	-	-
1080000	AC PR DPR EL PL SR 3602000	LAND RIGHTS	WYU	(1,336)	-	-	-	(1,336)	-	-	-	-
1080000	AC PR DPR EL PL SR 3610000	STRUCTURES & IMPROVEMENTS	CA	(1,649)	(1,649)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3610000	STRUCTURES & IMPROVEMENTS	IDU	(868)	-	-	-	-	-	(868)	-	-
1080000	AC PR DPR EL PL SR 3610000	STRUCTURES & IMPROVEMENTS	OR	(9,016)	-	(9,016)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3610000	STRUCTURES & IMPROVEMENTS	UT	(15,363)	-	-	-	-	(15,363)	-	-	-



Depreciation Reserve (Actuals)  
 Year End: 06/2021  
 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	3610000	STRUCTURES & IMPROVEMENTS	WA	(1,365)	-	-	(1,365)	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WYP	(4,089)	-	-	-	(4,089)	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WYU	(822)	-	-	-	(822)	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	CA	(10,809)	(10,809)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	IDU	(11,795)	-	-	-	-	(11,795)	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	OR	(99,689)	-	(99,689)	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	UT	(152,205)	-	-	-	(152,205)	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WA	(26,771)	-	-	(26,771)	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WYP	(43,628)	-	-	-	(43,628)	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WYU	(4,086)	-	-	-	(4,086)	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	(128)	(128)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	(159)	-	-	-	-	(159)	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	(1,462)	-	(1,462)	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	(2,019)	-	-	-	(2,019)	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	(454)	-	-	(454)	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	(803)	-	-	-	(803)	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	(32)	-	-	-	(32)	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	CA	(43,172)	(43,172)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	IDU	(47,851)	-	-	-	-	(47,851)	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	OR	(255,299)	-	(255,299)	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	UT	(166,924)	-	-	-	(166,924)	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WA	(75,631)	-	-	(75,631)	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WYP	(71,674)	-	-	-	(71,674)	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WYU	(15,885)	-	-	-	(15,885)	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	(22,535)	(22,535)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	(16,623)	-	-	-	-	(16,623)	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	(138,404)	-	(138,404)	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	(85,064)	-	-	-	(85,064)	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	(37,212)	-	-	(37,212)	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	(43,458)	-	-	-	(43,458)	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	(5,879)	-	-	-	(5,879)	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	CA	(13,101)	(13,101)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	IDU	(4,630)	-	-	-	-	(4,630)	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	OR	(48,957)	-	(48,957)	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	UT	(87,498)	-	-	-	(87,498)	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WA	(11,065)	-	-	(11,065)	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WYP	(11,112)	-	-	-	(11,112)	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WYU	(3,067)	-	-	-	(3,067)	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	(13,608)	(13,608)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	(12,873)	-	-	-	-	(12,873)	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	(96,546)	-	(96,546)	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	(205,056)	-	-	-	(205,056)	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	(13,563)	-	-	(13,563)	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	(24,753)	-	-	-	(24,753)	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	(14,118)	-	-	-	(14,118)	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	CA	(30,499)	(30,499)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	IDU	(33,737)	-	-	-	-	(33,737)	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	OR	(252,938)	-	(252,938)	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	UT	(166,991)	-	-	-	(166,991)	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WA	(64,804)	-	-	(64,804)	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WYP	(48,198)	-	-	-	(48,198)	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WYU	(7,651)	-	-	-	(7,651)	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	CA	(4,273)	(4,273)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	IDU	(4,818)	-	-	-	-	(4,818)	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	OR	(46,488)	-	(46,488)	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	UT	(40,295)	-	-	-	(40,295)	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WA	(9,716)	-	-	(9,716)	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WYP	(7,400)	-	-	-	(7,400)	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WYU	(1,198)	-	-	-	(1,198)	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	CA	(9,134)	(9,134)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	IDU	(13,861)	-	-	-	-	(13,861)	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	OR	(99,435)	-	(99,435)	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	UT	(76,250)	-	-	-	(76,250)	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WA	(23,183)	-	-	(23,183)	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WYP	(20,337)	-	-	-	(20,337)	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WYU	(5,794)	-	-	-	(5,794)	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	CA	(721)	(721)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	IDU	(10,964)	-	-	-	-	(10,964)	-
1080000	AC PR DPR EL PL SR	3700000	METERS	OR	(22,472)	-	(22,472)	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	UT	(55,963)	-	-	-	(55,963)	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	WA	(8,063)	-	-	(8,063)	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	WYP	(8,024)	-	-	-	(8,024)	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	WYU	(1,639)	-	-	-	(1,639)	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	CA	(259)	(259)	-	-	-	-	-



Depreciation Reserve (Actuals)  
 Year End: 06/2021  
 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	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	(126)	-	-	-	-	(126)	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	OR	(2,126)	(2,126)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	UT	(3,333)	-	-	-	(3,333)	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WA	(424)	-	(424)	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	(814)	-	-	(814)	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	(138)	-	-	-	(138)	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	(403)	(403)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	(461)	-	-	-	-	(461)	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	(12,787)	(12,787)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	(13,606)	-	-	-	(13,606)	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	(1,751)	-	(1,751)	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	(3,966)	-	-	(3,966)	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	(1,262)	-	-	-	(1,262)	-	-
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	(0)	(0)	(0)	(0)	(0)	(0)	(0)
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	SO	(4)	(0)	(1)	(0)	(1)	(2)	(0)
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	UT	(21)	-	-	-	(21)	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	WYP	(11)	-	-	-	(11)	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	WYU	(5)	-	-	-	(5)	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	CA	(843)	(843)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	CN	(2,471)	(58)	(766)	(169)	(180)	(1,194)	(105)
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	IDU	(5,094)	-	-	-	-	(5,094)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	OR	(10,943)	-	(10,943)	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SE	(238)	(3)	(60)	(18)	(37)	(105)	(15)
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SG	(2,959)	(43)	(771)	(232)	(420)	(1,314)	(178)
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SO	(31,737)	(700)	(8,624)	(2,436)	(4,172)	(13,944)	(1,854)
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	UT	(13,305)	-	-	-	-	(13,305)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WA	(7,870)	-	(7,870)	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WYP	(1,780)	-	-	(1,780)	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WYU	(1,498)	-	-	-	(1,498)	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	CA	(92)	(92)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	CN	(863)	(20)	(267)	(59)	(63)	(417)	(37)
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	IDU	(26)	-	-	-	-	(26)	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	OR	(1,081)	-	(1,081)	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SE	(2)	(0)	(1)	(0)	(0)	(1)	(0)
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SG	(824)	(12)	(215)	(65)	(117)	(366)	(49)
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SO	(6,911)	(152)	(1,878)	(531)	(909)	(3,036)	(404)
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	UT	(338)	-	-	-	-	(338)	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WA	(40)	-	(40)	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WYP	(256)	-	-	(256)	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WYU	(15)	-	-	-	(15)	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	(23)	(23)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	(1,891)	(44)	(586)	(129)	(138)	(913)	(80)
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	(203)	-	-	-	-	(203)	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	(464)	-	(464)	-	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	(10)	(0)	(2)	(1)	(1)	(4)	(1)
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	(1,119)	(16)	(292)	(88)	(159)	(497)	(67)
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	(24,033)	(530)	(6,530)	(1,845)	(3,160)	(10,559)	(1,404)
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	(239)	-	-	-	-	(239)	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	(185)	-	(185)	-	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	(942)	-	-	(942)	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	(17)	-	-	-	(17)	-	-
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	OR	(2)	-	(2)	-	-	-	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	SG	(25)	(0)	(7)	(2)	(4)	(11)	(2)
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	SO	(56)	(1)	(15)	(4)	(7)	(25)	(3)
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	UT	(4)	-	-	-	-	(4)	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	WYU	(4)	-	-	-	(4)	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	CA	(33)	(33)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	IDU	(161)	-	-	-	-	(161)	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	(807)	-	(807)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SE	(18)	(0)	(5)	(1)	(3)	(8)	(1)
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	(318)	(5)	(83)	(25)	(45)	(141)	(19)
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	(455)	(10)	(124)	(35)	(60)	(200)	(27)
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	(1,412)	-	-	-	-	(1,412)	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	(147)	-	(147)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	(259)	-	-	(259)	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	OR	(52)	-	(52)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	SO	(47)	(1)	(13)	(4)	(6)	(21)	(3)
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	UT	(198)	-	-	-	-	(198)	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	WA	(5)	-	-	(5)	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	WYP	(14)	-	-	-	(14)	-	-
1080000	AC PR DPR EL PL SR	3920400	*1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	(197)	(197)	-	-	-	-	-



Depreciation Reserve (Actuals)  
 Year End: 06/2021  
 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 3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	(849)	-	-	-	-	(849)	-	-
1080000	AC PR DPR EL PL SR 3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	(2,795)	-	(2,795)	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	(48)	(1)	(12)	(4)	(7)	(21)	(3)	(0)
1080000	AC PR DPR EL PL SR 3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	(4,464)	(66)	(1,164)	(350)	(634)	(1,982)	(268)	(1)
1080000	AC PR DPR EL PL SR 3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	(718)	(16)	(195)	(55)	(94)	(315)	(42)	(0)
1080000	AC PR DPR EL PL SR 3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	(4,562)	-	-	-	-	(4,562)	-	-
1080000	AC PR DPR EL PL SR 3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	(958)	-	-	(958)	-	-	-	-
1080000	AC PR DPR EL PL SR 3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	(751)	-	-	-	(751)	-	-	-
1080000	AC PR DPR EL PL SR 3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	(217)	-	-	-	(217)	-	-	-
1080000	AC PR DPR EL PL SR 3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	(409)	(409)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	(1,389)	-	-	-	-	(1,389)	-	-
1080000	AC PR DPR EL PL SR 3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	(7,766)	-	(7,766)	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	(155)	(2)	(39)	(11)	(24)	(68)	(10)	(0)
1080000	AC PR DPR EL PL SR 3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	(3,604)	(53)	(939)	(282)	(511)	(1,600)	(216)	(1)
1080000	AC PR DPR EL PL SR 3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	(201)	(4)	(55)	(15)	(26)	(88)	(12)	(0)
1080000	AC PR DPR EL PL SR 3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	(9,098)	-	-	-	-	(9,098)	-	-
1080000	AC PR DPR EL PL SR 3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	(1,754)	-	-	(1,754)	-	-	-	-
1080000	AC PR DPR EL PL SR 3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	(1,732)	-	-	-	(1,732)	-	-	-
1080000	AC PR DPR EL PL SR 3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	(413)	-	-	-	(413)	-	-	-
1080000	AC PR DPR EL PL SR 3920600	DUMP TRUCKS	OR	(117)	-	(117)	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3920600	DUMP TRUCKS	SE	(3)	(0)	(1)	(0)	(1)	(1)	(0)	(0)
1080000	AC PR DPR EL PL SR 3920600	DUMP TRUCKS	SG	(2,117)	(31)	(552)	(166)	(300)	(940)	(127)	(1)
1080000	AC PR DPR EL PL SR 3920600	DUMP TRUCKS	UT	(107)	-	-	-	-	(107)	-	-
1080000	AC PR DPR EL PL SR 3920900	TRAILERS	CA	(201)	(201)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3920900	TRAILERS	IDU	(404)	-	-	-	-	(404)	-	-
1080000	AC PR DPR EL PL SR 3920900	TRAILERS	OR	(1,553)	-	(1,553)	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3920900	TRAILERS	SE	(30)	(0)	(7)	(2)	(5)	(13)	(2)	(0)
1080000	AC PR DPR EL PL SR 3920900	TRAILERS	SG	(723)	(11)	(188)	(57)	(103)	(321)	(43)	(0)
1080000	AC PR DPR EL PL SR 3920900	TRAILERS	SO	(315)	(7)	(86)	(24)	(41)	(139)	(18)	(0)
1080000	AC PR DPR EL PL SR 3920900	TRAILERS	UT	(3,129)	-	-	-	-	(3,129)	-	-
1080000	AC PR DPR EL PL SR 3920900	TRAILERS	WA	(366)	-	-	(366)	-	-	-	-
1080000	AC PR DPR EL PL SR 3920900	TRAILERS	WYP	(1,161)	-	-	-	(1,161)	-	-	-
1080000	AC PR DPR EL PL SR 3920900	TRAILERS	WYU	(234)	-	-	-	(234)	-	-	-
1080000	AC PR DPR EL PL SR 3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	(61)	(61)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	(43)	-	-	-	-	(43)	-	-
1080000	AC PR DPR EL PL SR 3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	(225)	-	(225)	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SE	(4)	(0)	(1)	(0)	(1)	(2)	(0)	(0)
1080000	AC PR DPR EL PL SR 3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	(410)	(6)	(107)	(32)	(58)	(182)	(25)	(0)
1080000	AC PR DPR EL PL SR 3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	(34)	(1)	(9)	(3)	(5)	(15)	(2)	(0)
1080000	AC PR DPR EL PL SR 3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	(165)	-	-	-	-	(165)	-	-
1080000	AC PR DPR EL PL SR 3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	(57)	-	-	(57)	-	-	-	-
1080000	AC PR DPR EL PL SR 3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYP	(110)	-	-	-	(110)	-	-	-
1080000	AC PR DPR EL PL SR 3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	(16)	-	-	-	(16)	-	-	-
1080000	AC PR DPR EL PL SR 3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	(225)	-	(225)	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	(320)	(5)	(83)	(25)	(45)	(142)	(19)	(0)
1080000	AC PR DPR EL PL SR 3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	(139)	(3)	(38)	(11)	(18)	(61)	(8)	(0)
1080000	AC PR DPR EL PL SR 3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	(694)	-	-	-	-	(694)	-	-
1080000	AC PR DPR EL PL SR 3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	(150)	-	-	(150)	-	-	-	-
1080000	AC PR DPR EL PL SR 3921900	OVER-THE-ROAD SEMI-TRACTORS	WYP	(53)	-	-	-	(53)	-	-	-
1080000	AC PR DPR EL PL SR 3923000	TRANSPORTATION EQUIPMENT	SO	(1,085)	(24)	(295)	(83)	(143)	(477)	(63)	(0)
1080000	AC PR DPR EL PL SR 3930000	STORES EQUIPMENT	CA	(109)	(109)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3930000	STORES EQUIPMENT	IDU	(280)	-	-	-	-	(280)	-	-
1080000	AC PR DPR EL PL SR 3930000	STORES EQUIPMENT	OR	(1,363)	-	(1,363)	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3930000	STORES EQUIPMENT	SG	(2,664)	(39)	(695)	(209)	(378)	(1,183)	(160)	(1)
1080000	AC PR DPR EL PL SR 3930000	STORES EQUIPMENT	SO	(135)	(3)	(37)	(10)	(18)	(59)	(8)	(0)
1080000	AC PR DPR EL PL SR 3930000	STORES EQUIPMENT	UT	(1,664)	-	-	-	-	(1,664)	-	-
1080000	AC PR DPR EL PL SR 3930000	STORES EQUIPMENT	WA	(376)	-	-	(376)	-	-	-	-
1080000	AC PR DPR EL PL SR 3930000	STORES EQUIPMENT	WYP	(536)	-	-	-	(536)	-	-	-
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	(377)	(377)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	(1,136)	-	-	-	-	(1,136)	-	-
1080000	AC PR DPR EL PL SR 3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	(5,413)	-	(5,413)	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	(76)	(1)	(19)	(6)	(12)	(34)	(5)	(0)
1080000	AC PR DPR EL PL SR 3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	(11,430)	(168)	(2,980)	(896)	(1,622)	(5,074)	(686)	(3)
1080000	AC PR DPR EL PL SR 3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	(1,461)	(32)	(397)	(112)	(192)	(642)	(85)	(0)
1080000	AC PR DPR EL PL SR 3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	(7,174)	-	-	-	-	(7,174)	-	-
1080000	AC PR DPR EL PL SR 3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	(1,313)	-	-	(1,313)	-	-	-	-
1080000	AC PR DPR EL PL SR 3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	(1,916)	-	-	-	(1,916)	-	-	-
1080000	AC PR DPR EL PL SR 3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	(301)	-	-	-	(301)	-	-	-
1080000	AC PR DPR EL PL SR 3950000	LABORATORY EQUIPMENT	CA	(174)	(174)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3950000	LABORATORY EQUIPMENT	IDU	(726)	-	-	-	-	(726)	-	-
1080000	AC PR DPR EL PL SR 3950000	LABORATORY EQUIPMENT	OR	(4,259)	-	(4,259)	-	-	-	-	-
1080000	AC PR DPR EL PL SR 3950000	LABORATORY EQUIPMENT	SE	(636)	(9)	(159)	(47)	(98)	(281)	(41)	(0)
1080000	AC PR DPR EL PL SR 3950000	LABORATORY EQUIPMENT	SG	(3,621)	(53)	(944)	(284)	(514)	(1,608)	(217)	(1)



Depreciation Reserve (Actuals)  
 Year End: 06/2021  
 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	3950000	LABORATORY EQUIPMENT	SO	(2,780)	(61)	(755)	(213)	(365)	(1,221)	(162)	(1)	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	UT	(3,831)	-	-	-	-	(3,831)	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WA	(771)	-	-	(771)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WYP	(1,302)	-	-	-	(1,302)	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WYU	(82)	-	-	-	(82)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	CA	(782)	(782)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	IDU	(1,538)	-	-	-	-	(1,538)	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	OR	(7,928)	-	(7,928)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SG	(330)	(5)	(86)	(26)	(47)	(146)	(20)	(0)	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SO	(1,089)	(24)	(296)	(84)	(143)	(479)	(64)	(0)	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	UT	(6,074)	-	-	-	-	(6,074)	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WA	(1,738)	-	-	(1,738)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYP	(2,497)	-	-	-	(2,497)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYU	(450)	-	-	-	(450)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	CA	(42)	(42)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	(114)	-	-	-	-	(114)	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	(448)	-	(448)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	(78)	(1)	(20)	(6)	(11)	(35)	(5)	(0)	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	(232)	-	-	-	-	(232)	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	(96)	-	-	-	(96)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	*AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	(413)	(413)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	*AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	(946)	-	-	-	-	(946)	-	-	-
1080000	AC PR DPR EL PL SR	3960800	*AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	(5,340)	-	(5,340)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	*AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	(589)	(9)	(154)	(46)	(84)	(262)	(35)	(0)	-
1080000	AC PR DPR EL PL SR	3960800	*AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	(700)	(15)	(190)	(54)	(92)	(308)	(41)	(0)	-
1080000	AC PR DPR EL PL SR	3960800	*AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	(5,070)	-	-	-	-	(5,070)	-	-	-
1080000	AC PR DPR EL PL SR	3960800	*AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	(1,717)	-	-	(1,717)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	*AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	(1,310)	-	-	-	(1,310)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	*AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	(255)	-	-	-	(255)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	OR	(204)	-	(204)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	SG	(1,228)	(18)	(320)	(96)	(174)	(545)	(74)	(0)	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	UT	(1)	-	-	-	-	(1)	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	OR	(423)	-	(423)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SG	(8,838)	(130)	(2,304)	(693)	(1,254)	(3,924)	(531)	(3)	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	(568)	(13)	(154)	(44)	(75)	(250)	(33)	(0)	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	(637)	-	-	-	-	(637)	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	(166)	-	-	-	(166)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	(496)	(496)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	(1,043)	-	-	-	-	(1,043)	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	(4,746)	-	(4,746)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	(183)	(3)	(48)	(14)	(26)	(81)	(11)	(0)	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	(701)	(15)	(191)	(54)	(92)	(308)	(41)	(0)	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	(5,681)	-	-	-	-	(5,681)	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	(1,156)	-	-	(1,156)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	(1,094)	-	-	-	(1,094)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	(211)	-	-	-	(211)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	CA	(255)	(255)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	IDU	(589)	-	-	-	-	(589)	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	OR	(1,139)	-	(1,139)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SE	(117)	(2)	(29)	(9)	(18)	(52)	(8)	(0)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	(2,519)	(37)	(657)	(197)	(358)	(1,119)	(151)	(1)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	(264)	(6)	(72)	(20)	(35)	(116)	(15)	(0)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	UT	(2,053)	-	-	-	-	(2,053)	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WA	(610)	-	-	(610)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYP	(529)	-	-	-	(529)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYU	(231)	-	-	-	(231)	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	CA	(2,488)	(2,488)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	CN	(1,993)	(47)	(618)	(136)	(145)	(963)	(85)	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	IDU	(5,128)	-	-	-	-	(5,128)	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	OR	(38,764)	-	(38,764)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SE	(131)	(2)	(33)	(10)	(20)	(58)	(8)	(0)	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SG	(77,400)	(1,136)	(20,178)	(6,067)	(10,986)	(34,362)	(4,649)	(23)	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SO	(42,483)	(937)	(11,544)	(3,261)	(5,585)	(18,665)	(2,482)	(9)	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	UT	(24,936)	-	-	-	-	(24,936)	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	WA	(5,259)	-	-	(5,259)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	WYP	(10,343)	-	-	-	(10,343)	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	WYU	(2,594)	-	-	-	(2,594)	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	CA	(233)	(233)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	IDU	(241)	-	-	-	-	(241)	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	OR	(1,961)	-	(1,961)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	SE	(67)	(1)	(17)	(5)	(10)	(30)	(4)	(0)	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	SG	(3,031)	(44)	(790)	(238)	(430)	(1,346)	(182)	(1)	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	SO	(443)	(10)	(120)	(34)	(58)	(195)	(26)	(0)	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	UT	(1,550)	-	-	-	-	(1,550)	-	-	-





Depreciation Reserve (Actuals)  
 Year End: 06/2021  
 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	3972000	MOBILE RADIO EQUIPMENT	WA	(407)	-	-	(407)	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	WYP	(483)	-	-	-	(483)	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	WYU	(86)	-	-	-	(86)	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	CA	(28)	(28)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	CN	(51)	(1)	(16)	(4)	(4)	(25)	(2)	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	IDU	(36)	-	-	-	-	-	(36)	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	OR	(576)	-	(576)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SE	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SG	(1,436)	(21)	(374)	(113)	(204)	(637)	(86)	(0)
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SO	(1,414)	(31)	(384)	(109)	(186)	(621)	(83)	(0)
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	UT	(574)	-	-	-	-	(574)	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WA	(96)	-	-	(96)	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WYP	(81)	-	-	-	(81)	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WYU	(12)	-	-	-	(12)	-	-	-
<b>1080000 Total</b>					<b>(9,644,079)</b>	<b>(251,238)</b>	<b>(2,822,212)</b>	<b>(790,204)</b>	<b>(1,274,573)</b>	<b>(3,948,699)</b>	<b>(555,331)</b>	<b>(1,822)</b>
1083000	AC PR DPR-REMOVAL	288351	Reg Liab Contra - Carbon Decomm - ID	IDU	1,213	-	-	-	-	1,213	-	-
1083000	AC PR DPR-REMOVAL	288353	Reg Liab Contra - Carbon Decomm - UT	UT	(8,527)	-	-	-	-	(8,527)	-	-
1083000	AC PR DPR-REMOVAL	288365	Reg Liab - Steam Decomm - WA	WA	(1,785)	-	-	(1,785)	-	-	-	-
<b>1083000 Total</b>					<b>(9,099)</b>	<b>-</b>	<b>-</b>	<b>(1,785)</b>	<b>-</b>	<b>(8,527)</b>	<b>1,213</b>	<b>-</b>
1085000	AC PR DPR-ACCRUAL	145129	BUILDINGS - ACCUMULATED DEPRECIATION-NON	SO	1,246	27	339	96	164	548	73	0
1085000	AC PR DPR-ACCRUAL	145131	Accum Depr - Hydro - ID Klamath Adj	OTHER	620	-	-	-	-	-	-	620
1085000	AC PR DPR-ACCRUAL	145134	Accum Depr - Hydro - WY Klamath Adj	OTHER	1,484	-	-	-	-	-	-	1,484
1085000	AC PR DPR-ACCRUAL	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-P	(6,967)	(102)	(1,816)	(546)	(989)	(3,093)	(418)	(2)
1085000	AC PR DPR-ACCRUAL	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-U	(289)	(4)	(75)	(23)	(41)	(129)	(17)	(0)
1085000	AC PR DPR-ACCRUAL	145139	PRODUCTION PLANT-ACCUM DEPRECIATION	SG	19,189	282	5,003	1,504	2,723	8,519	1,152	6
1085000	AC PR DPR-ACCRUAL	145149	TRANSMISSION PLANT ACCUMULATED DEPR NON-	SG	5,037	74	1,313	395	715	2,236	303	1
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	CA	381	381	-	-	-	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	IDU	282	-	-	-	-	-	282	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	OR	2,062	-	2,062	-	-	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	UT	2,090	-	-	-	-	2,090	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WA	523	-	-	523	-	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WYU	758	-	-	-	-	758	-	-
<b>1085000 Total</b>					<b>26,416</b>	<b>657</b>	<b>6,824</b>	<b>1,949</b>	<b>3,331</b>	<b>10,171</b>	<b>1,374</b>	<b>5</b>
<b>Grand Total</b>					<b>(9,626,762)</b>	<b>(250,581)</b>	<b>(2,815,387)</b>	<b>(790,040)</b>	<b>(1,271,243)</b>	<b>(3,947,055)</b>	<b>(552,744)</b>	<b>(1,816)</b>

# **B18.AMORTIZATION RESERVE**



Amortization Reserve (Actuals)  
 Year End: 06/2021  
 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 SR 3020000	FRANCHISES AND CONSENTS	IDU (966)	-	-	-	-	-	(966)	-	-
1110000	AC PR AMR EL PT SR 3020000	FRANCHISES AND CONSENTS	SG (5,501)	(81)	(1,434)	(431)	(781)	(2,442)	(330)	(2)	-
1110000	AC PR AMR EL PT SR 3020000	FRANCHISES AND CONSENTS	SG-P (114,429)	(1,679)	(29,832)	(8,970)	(16,241)	(50,801)	(6,872)	(33)	-
1110000	AC PR AMR EL PT SR 3020000	FRANCHISES AND CONSENTS	SG-U (6,141)	(90)	(1,601)	(481)	(872)	(2,726)	(369)	(2)	-
1110000	AC PR AMR EL PT SR 3020000	FRANCHISES AND CONSENTS	UT 32,081	-	-	-	-	32,081	-	-	-
1110000	AC PR AMR EL PT SR 3031040	INTANGIBLE PLANT	OR (122)	-	(122)	-	-	-	-	-	-
1110000	AC PR AMR EL PT SR 3031040	INTANGIBLE PLANT	SG (16,872)	(248)	(4,398)	(1,323)	(2,395)	(7,490)	(1,013)	(5)	-
1110000	AC PR AMR EL PT SR 3031040	INTANGIBLE PLANT	UT (88)	-	-	-	-	(88)	-	-	-
1110000	AC PR AMR EL PT SR 3031040	INTANGIBLE PLANT	WYP (173)	-	-	-	(173)	-	-	-	-
1110000	AC PR AMR EL PT SR 3031050	REGIONAL CONST MGMT SYS	SO (11,031)	(243)	(2,997)	(847)	(1,450)	(4,846)	(644)	(2)	-
1110000	AC PR AMR EL PT SR 3031080	FUEL MGMT SYSTEM	SO (3,293)	(73)	(895)	(253)	(433)	(1,447)	(192)	(1)	-
1110000	AC PR AMR EL PT SR 3031230	AUTOMATE POLE CARD SYSTEM	SO (4,410)	(97)	(1,198)	(339)	(580)	(1,937)	(258)	(1)	-
1110000	AC PR AMR EL PT SR 3031680	DISTRIBUTION AUTOMATION PILOT	SO (13,886)	(306)	(3,773)	(1,066)	(1,826)	(6,101)	(811)	(3)	-
1110000	AC PR AMR EL PT SR 3031830	CUSTOMER SERVICE SYSTEM	CN (124,697)	(2,923)	(38,644)	(8,535)	(9,079)	(60,226)	(5,290)	-	-
1110000	AC PR AMR EL PT SR 3032040	SAP	SO (159,158)	(3,510)	(43,248)	(12,218)	(20,924)	(69,927)	(9,298)	(33)	-
1110000	AC PR AMR EL PT SR 3032130	PROD & TRANS PLANT	SG (195)	(3)	(51)	(15)	(28)	(86)	(12)	(0)	-
1110000	AC PR AMR EL PT SR 3032140	MINING PLANT	SO (135)	(3)	(37)	(10)	(18)	(59)	(8)	(0)	-
1110000	AC PR AMR EL PT SR 3032150	HYDRO PLANT	SO (315)	(7)	(86)	(24)	(41)	(139)	(18)	(0)	-
1110000	AC PR AMR EL PT SR 3032220	ENTERPRISE DATA WRHSE - BI RPTG TOOL	SO (1,660)	(37)	(451)	(127)	(218)	(729)	(97)	(0)	-
1110000	AC PR AMR EL PT SR 3032270	ENTERPRISE DATA WAREHOUSE	SO (5,877)	(130)	(1,597)	(451)	(773)	(2,582)	(343)	(1)	-
1110000	AC PR AMR EL PT SR 3032330	FIELDNET PRO METER READING SYST -HRP REP	SO (2,908)	(64)	(790)	(223)	(382)	(1,278)	(170)	(1)	-
1110000	AC PR AMR EL PT SR 3032340	FACILITY INSPECTION REPORTING SYSTEM	SO (2,000)	(44)	(543)	(154)	(263)	(879)	(117)	(0)	-
1110000	AC PR AMR EL PT SR 3032360	2002 GRID NET POWER COST MODELING	SO (8,958)	(198)	(2,434)	(688)	(1,178)	(3,936)	(523)	(2)	-
1110000	AC PR AMR EL PT SR 3032450	MID OFFICE IMPROVEMENT PROJECT	SO (10,561)	(233)	(2,870)	(811)	(1,388)	(4,640)	(617)	(2)	-
1110000	AC PR AMR EL PT SR 3032510	OPERATIONS MAPPING SYSTEM	SO (10,386)	(229)	(2,822)	(797)	(1,365)	(4,563)	(607)	(2)	-
1110000	AC PR AMR EL PT SR 3032530	POLE ATTACHMENT MGMT SYSTEM	SO (1,892)	(42)	(514)	(145)	(249)	(831)	(111)	(0)	-
1110000	AC PR AMR EL PT SR 3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO (2,416)	(53)	(656)	(185)	(318)	(1,061)	(141)	(0)	-
1110000	AC PR AMR EL PT SR 3032600	SINGLE PERSON SCHEDULING	SO (13,003)	(287)	(3,533)	(998)	(1,709)	(5,713)	(760)	(3)	-
1110000	AC PR AMR EL PT SR 3032640	TIBCO SOFTWARE	SO (6,371)	(140)	(1,731)	(489)	(838)	(2,799)	(372)	(1)	-
1110000	AC PR AMR EL PT SR 3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG (1,599)	(23)	(417)	(125)	(227)	(710)	(96)	(0)	-
1110000	AC PR AMR EL PT SR 3032690	UTILITY INTERNATIONAL FORECASTING MODEL	SO (669)	(15)	(182)	(51)	(88)	(294)	(39)	(0)	-
1110000	AC PR AMR EL PT SR 3032710	ROUGE RIVER HYDRO INTANGIBLES	SG (97)	(1)	(25)	(8)	(14)	(43)	(6)	(0)	-
1110000	AC PR AMR EL PT SR 3032740	GADSBY INTANGIBLE ASSETS	SG (10)	(0)	(3)	(1)	(1)	(5)	(1)	(0)	-
1110000	AC PR AMR EL PT SR 3032760	SWIFT 2 IMPROVEMENTS	SG (7,277)	(107)	(1,897)	(570)	(1,033)	(3,231)	(437)	(2)	-
1110000	AC PR AMR EL PT SR 3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG (235)	(3)	(61)	(18)	(33)	(104)	(14)	(0)	-
1110000	AC PR AMR EL PT SR 3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG (69)	(1)	(18)	(5)	(10)	(31)	(4)	(0)	-
1110000	AC PR AMR EL PT SR 3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG-U (12)	(0)	(3)	(1)	(2)	(5)	(1)	(0)	-
1110000	AC PR AMR EL PT SR 3032830	VCPRO - VISUALCOMPUSETPRO XEROX CUST STM	SO (2,579)	(57)	(701)	(198)	(339)	(1,133)	(151)	(1)	-
1110000	AC PR AMR EL PT SR 3032860	WEB SOFTWARE	SO (6,320)	(139)	(1,717)	(485)	(831)	(2,777)	(369)	(1)	-
1110000	AC PR AMR EL PT SR 3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSET	SG (3,507)	(51)	(914)	(275)	(498)	(1,557)	(211)	(1)	-
1110000	AC PR AMR EL PT SR 3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO (5,827)	(128)	(1,583)	(447)	(766)	(2,560)	(340)	(1)	-
1110000	AC PR AMR EL PT SR 3033090	STEAM PLANT INTANGIBLE ASSETS	SG (31,689)	(465)	(8,261)	(2,484)	(4,498)	(14,068)	(1,903)	(9)	-
1110000	AC PR AMR EL PT SR 3033170	GTX VERSION 7 SOFTWARE	CN (7,430)	(174)	(2,303)	(509)	(541)	(3,589)	(315)	-	-
1110000	AC PR AMR EL PT SR 3033190	ITRON METER READING SOFTWARE	CN (5,868)	(138)	(1,819)	(402)	(427)	(2,834)	(249)	-	-
1110000	AC PR AMR EL PT SR 3033210	ARCFM SOFTWARE	SO (3,978)	(88)	(1,081)	(305)	(523)	(1,748)	(232)	(1)	-
1110000	AC PR AMR EL PT SR 3033220	MONARCH EMS/SCADA	SO (15,202)	(335)	(4,131)	(1,167)	(1,999)	(6,679)	(888)	(3)	-
1110000	AC PR AMR EL PT SR 3033240	IEE - Itron Enterprise Addition	CN (3,650)	(86)	(1,131)	(250)	(266)	(1,763)	(155)	-	-
1110000	AC PR AMR EL PT SR 3033250	AMI Metering Software	CN (14,644)	(343)	(4,538)	(1,002)	(1,066)	(7,073)	(621)	-	-
1110000	AC PR AMR EL PT SR 3033260	Big Data & Analytics	SO (1,267)	(28)	(344)	(97)	(167)	(557)	(74)	(0)	-
1110000	AC PR AMR EL PT SR 3033270	CES - Customer Experience System	CN (1,035)	(24)	(321)	(71)	(75)	(500)	(44)	-	-
1110000	AC PR AMR EL PT SR 3033280	MAPAPPS - Mapping Systems Application	SO (300)	(7)	(82)	(23)	(39)	(132)	(18)	(0)	-
1110000	AC PR AMR EL PT SR 3033290	CUSTOMER CONTACTS	CN (94)	(2)	(29)	(6)	(7)	(46)	(4)	-	-
1110000	AC PR AMR EL PT SR 3033300	SECID - CUST SECURE WEB LOGIN	CN (1,085)	(25)	(336)	(74)	(79)	(524)	(46)	-	-
1110000	AC PR AMR EL PT SR 3033310	C&T - ENERGY TRADING SYSTEM	SO (18,769)	(414)	(5,100)	(1,441)	(2,468)	(8,246)	(1,097)	(4)	-
1110000	AC PR AMR EL PT SR 3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG (9,971)	(146)	(2,599)	(782)	(1,415)	(4,426)	(599)	(3)	-
1110000	AC PR AMR EL PT SR 3033370	DISTRIBUTION INTANGIBLES	WYP (37)	-	-	-	(37)	-	-	-	-
1110000	AC PR AMR EL PT SR 3033380	MISCELLANEOUS SMALL SOFTWARE PACKAGES	SG (782)	(11)	(204)	(61)	(111)	(347)	(47)	(0)	-
1110000	AC PR AMR EL PT SR 3033390	RMT TRADE SYSTEM	SO (923)	(20)	(251)	(71)	(121)	(406)	(54)	(0)	-
1110000	AC PR AMR EL PT SR 3033410	M365	SO (31)	(1)	(8)	(2)	(4)	(14)	(2)	(0)	-
1110000	AC PR AMR EL PT SR 3034900	MISC - MISCELLANEOUS	CA (6)	(6)	-	-	-	-	-	-	-
1110000	AC PR AMR EL PT SR 3034900	MISC - MISCELLANEOUS	CN (3)	(0)	(1)	(0)	(0)	(1)	(0)	-	-



**Amortization Reserve (Actuals)**

Year End: 06/2021

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 SR	3034900	MISC - MISCELLANEOUS	IDU	(10)	-	-	-	-	(10)	-	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	OR	(7)	-	(7)	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	SE	(2)	(0)	(0)	(0)	(1)	(0)	(0)	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	SG	(27,403)	(402)	(7,144)	(2,148)	(3,889)	(12,165)	(1,646)	(8)
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	SO	(1,234)	(27)	(335)	(95)	(162)	(542)	(72)	(0)
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	UT	(16)	-	-	-	(16)	-	-	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	WA	(11)	-	-	(11)	-	-	-	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	WYP	(166)	-	-	-	(166)	-	-	-
1110000	AC PR AMR EL PT SR	3035320	HYDRO PLANT INTANGIBLES	SG	(771)	(11)	(201)	(60)	(109)	(342)	(46)	(0)
1110000	AC PR AMR EL PT SR	3035320	HYDRO PLANT INTANGIBLES	SG-P	(116)	(2)	(30)	(9)	(16)	(52)	(7)	(0)
1110000	AC PR AMR EL PT SR	3035322	ACD-Call Center Automated Call Distribut	CN	(4,132)	(97)	(1,281)	(283)	(301)	(1,996)	(175)	-
1110000	AC PR AMR EL PT SR	3035330	OATI-OASIS INTERFACE	SO	(1,240)	(27)	(337)	(95)	(163)	(545)	(72)	(0)
1110000	AC PR AMR EL PT SR	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	(3,139)	(46)	(818)	(246)	(446)	(1,394)	(189)	(1)
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	(506)	(506)	-	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	IDU	(334)	-	-	-	-	(334)	-	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	(4,741)	-	(4,741)	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	(1,175)	(26)	(319)	(90)	(154)	(516)	(69)	(0)
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	(33)	-	-	-	-	(33)	-	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	(1,855)	-	-	(1,855)	-	-	-	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	(4,454)	-	-	-	(4,454)	-	-	-
<b>1110000 Total</b>					<b>(691,674)</b>	<b>(14,704)</b>	<b>(201,535)</b>	<b>(55,407)</b>	<b>(91,068)</b>	<b>(288,250)</b>	<b>(40,579)</b>	<b>(133)</b>
<b>Grand Total</b>					<b>(691,674)</b>	<b>(14,704)</b>	<b>(201,535)</b>	<b>(55,407)</b>	<b>(91,068)</b>	<b>(288,250)</b>	<b>(40,579)</b>	<b>(133)</b>

# **B19.D.I.T. BALANCE AND I.T.C.**



Deferred Income Tax Balance (Actuals)  
 Year End: 06/2021  
 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 287061	DTA 705.346 - CA - Protected PP&E ARAM	CA	599	599	-	-	-	-	-	-
1900000	ACM DEF INCM TAXES 287062	DTA 705.347 - ID - Protected PP&E ARAM	IDU	1,934	-	-	-	-	1,934	-	-
1900000	ACM DEF INCM TAXES 287063	DTA 705.348 - OR - Protected PP&E ARAM	OR	0	-	0	-	-	-	-	-
1900000	ACM DEF INCM TAXES 287064	DTA 705.349 - UT - Protected PP&E ARAM	UT	12,262	-	-	-	12,262	-	-	-
1900000	ACM DEF INCM TAXES 287065	DTA 705.350 - WA - Protected PP&E ARAM	WA	3,594	-	-	3,594	-	-	-	-
1900000	ACM DEF INCM TAXES 287066	DTA 705.351 - WY - Protected PP&E ARAM	WYU	8,727	-	-	-	8,727	-	-	-
<b>1900000 Total</b>				<b>27,117</b>	<b>599</b>	<b>0</b>	<b>3,594</b>	<b>8,727</b>	<b>12,262</b>	<b>1,934</b>	<b>-</b>
1901000	ACCUM DEF INC TAX 287045	DTA 610.155 RL - WA-Plant Closure Cost	WA	167	-	-	167	-	-	-	-
1901000	ACCUM DEF INC TAX 287047	DTA 610.150 RL-Bridger Acc Dep&Reclm-OR	OR	447	-	447	-	-	-	-	-
1901000	ACCUM DEF INC TAX 287048	DTA 705.425 RL-Bridger Accel Depr- WA	WA	313	-	-	313	-	-	-	-
1901000	ACCUM DEF INC TAX 287049	DTA 705.352 RL-Klamath Dams Removal-CA	CA	65	65	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX 287051	DTA 705.340 RL-Income Tax Deferral-CA	OTHER	1,004	-	-	-	-	-	-	1,004
1901000	ACCUM DEF INC TAX 287053	DTA 705.342 RL-Income Tax Deferral-OR	OTHER	2,417	-	-	-	-	-	-	2,417
1901000	ACCUM DEF INC TAX 287055	DTA 705.344 RL-Income Tax Deferral-WA	OTHER	2,269	-	-	-	-	-	-	2,269
1901000	ACCUM DEF INC TAX 287067	DTA 505.450 PMI Accrued Payroll Taxes	SE	259	4	65	19	40	115	17	0
1901000	ACCUM DEF INC TAX 287111	DTA 705.287 RL - Prot PP&E EDIT - CA	CA	8,243	8,243	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX 287112	DTA 705.288 RL - Prot PP&E EDIT - ID	IDU	21,025	-	-	-	-	21,025	-	-
1901000	ACCUM DEF INC TAX 287113	DTA 705.289 RL - Prot PP&E EDIT - OR	OR	92,188	-	92,188	-	-	-	-	-
1901000	ACCUM DEF INC TAX 287114	DTA 705.290 RL - Prot PP&E EDIT - WA	WA	22,135	-	-	22,135	-	-	-	-
1901000	ACCUM DEF INC TAX 287115	DTA 705.291 RL - Prot PP&E EDIT - WY	WYP	52,306	-	-	-	52,306	-	-	-
1901000	ACCUM DEF INC TAX 287116	DTA 705.292 RL - Prot PP&E EDIT - UT	UT	162,469	-	-	-	-	162,469	-	-
1901000	ACCUM DEF INC TAX 287121	DTA 705.294 RL-NonProt PP&E EDIT-CA	CA	578	578	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX 287122	DTA 705.295 RL-NonProt PP&E EDIT-ID	IDU	112	-	-	-	-	112	-	-
1901000	ACCUM DEF INC TAX 287124	DTA 705.296 RL-NonProt PP&E EDIT-WA	WA	5,900	-	-	5,900	-	-	-	-
1901000	ACCUM DEF INC TAX 287125	DTA 705.297 RL-NonProt PP&E EDIT-WY	WYP	10,859	-	-	-	10,859	-	-	-
1901000	ACCUM DEF INC TAX 287173	DTA 415.942 RL-Steam Decomm-WA	WA	439	-	-	439	-	-	-	-
1901000	ACCUM DEF INC TAX 287174	DTA 705.410 RL-Cholla Decomm-CA	CA	(7)	(7)	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX 287175	DTA 705.411 RL-Cholla Decomm-ID	IDU	(28)	-	-	-	-	(28)	-	-
1901000	ACCUM DEF INC TAX 287176	DTA 705.412 RL-Cholla Decomm-OR	OR	2,135	-	2,135	-	-	-	-	-
1901000	ACCUM DEF INC TAX 287177	DTA 705.413 RL-Cholla Decomm-UT	UT	4,819	-	-	-	-	4,819	-	-
1901000	ACCUM DEF INC TAX 287178	DTA 705.414 RL-Cholla Decomm-WY	WYP	(69)	-	-	-	(69)	-	-	-
1901000	ACCUM DEF INC TAX 287180	DTA 505.450 - Accrued Payroll Taxes	SO	6,149	136	1,671	472	808	2,701	359	1
1901000	ACCUM DEF INC TAX 287191	DTA 705.280 RL Excess Def Inc Taxes CA	CA	152	152	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX 287192	DTA 705.281 RL Excess Def Inc Taxes ID	IDU	14	-	-	-	-	14	-	-
1901000	ACCUM DEF INC TAX 287195	DTA 705.284 RL Excess Def Inc Taxes WA	WA	299	-	-	299	-	-	-	-
1901000	ACCUM DEF INC TAX 287196	DTA 705.285 RL Excess Def Inc Taxes WY	WYU	134	-	-	-	134	-	-	-
1901000	ACCUM DEF INC TAX 287198	DTA 320.279 FAS 158 Post-Retirement	SO	2,754	61	748	211	362	1,210	161	1
1901000	ACCUM DEF INC TAX 287199	DTA 220.101 Bad Debt	BADDEBT	(41)	(1)	(20)	(6)	(0)	(12)	(2)	-
1901000	ACCUM DEF INC TAX 287200	DTA 705.267 RL-WA Decoup Mech	OTHER	235	-	-	-	-	-	-	235
1901000	ACCUM DEF INC TAX 287206	DTA 415.710 RL-WA Accel Depr	WA	10,706	-	-	10,706	-	-	-	-
1901000	ACCUM DEF INC TAX 287209	DTA 705.266 RL-Energy Savings Assist-CA	OTHER	192	-	-	-	-	-	-	192
1901000	ACCUM DEF INC TAX 287211	DTA 425.226 - Deferred Revenue Other	OTHER	294	-	-	-	-	-	-	294
1901000	ACCUM DEF INC TAX 287212	DTA 705.245-RL-OR Dir Acc 5 yr Opt Out	OTHER	1,865	-	-	-	-	-	-	1,865
1901000	ACCUM DEF INC TAX 287214	DTA 910.245 - Contra Rec Joint Owners	SO	75	2	20	6	10	33	4	0
1901000	ACCUM DEF INC TAX 287216	DTA 605.715 Trapper Mine Contract Oblig	SE	1,877	27	470	138	290	830	121	1
1901000	ACCUM DEF INC TAX 287219	DTA 715.810 Chehalis Mitigation Oblig	SG	58	1	15	5	8	26	3	0
1901000	ACCUM DEF INC TAX 287220	DTA 720.560 Pension Liab UMWA Withdraw	SE	28,304	400	7,095	2,088	4,369	12,524	1,818	10
1901000	ACCUM DEF INC TAX 287225	DTA 605.103 ARO/Reg Diff - Trojan - WA	WA	8	-	-	8	-	-	-	-
1901000	ACCUM DEF INC TAX 287227	DTA 705.531 RL UT Solar Feed-in Tar - NC	OTHER	4,894	-	-	-	-	-	-	4,894
1901000	ACCUM DEF INC TAX 287229	DTA 705.527 RL CA Solar Feed-in Tar - NC	OTHER	(0)	-	-	-	-	-	-	(0)
1901000	ACCUM DEF INC TAX 287230	DTA 705.521 RL WY Def NPC - Noncurrent	OTHER	11	-	-	-	-	-	-	11
1901000	ACCUM DEF INC TAX 287231	DTA 705.519 RL WA Def NPC - Noncurrent	OTHER	3,705	-	-	-	-	-	-	3,705
1901000	ACCUM DEF INC TAX 287233	DTA 705.515 RL OR Def NPC - Noncurrent	OTHER	2,425	-	-	-	-	-	-	2,425
1901000	ACCUM DEF INC TAX 287235	DTA 705.511 RL CA Def NPC - Noncurrent	OTHER	130	-	-	-	-	-	-	130
1901000	ACCUM DEF INC TAX 287237	DTA 705.755 RL-NONCURRENT RECLASS-OTHE	OTHER	157	-	-	-	-	-	-	157
1901000	ACCUM DEF INC TAX 287238	DTA 705.420 RL - CA GHG Allowance Rev	OTHER	1,364	-	-	-	-	-	-	1,364
1901000	ACCUM DEF INC TAX 287253	DTA 705.400 Reg Lia - OR Inj & Dam Reser	OR	3,053	-	3,053	-	-	-	-	-



Deferred Income Tax Balance (Actuals)  
 Year End: 06/2021  
 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 287254	DTA 705.450 Reg Lia - CA Property Ins Re	CA	228	228	-	-	-	-	-	-	
1901000	ACCUM DEF INC TAX 287256	DTA 705.452 Reg Lia - WA Property Ins Re	WA	28	-	-	28	-	-	-	-	
1901000	ACCUM DEF INC TAX 287257	DTA 705.453 Reg Lia - ID Property Ins Re	IDU	261	-	-	-	-	261	-	-	
1901000	ACCUM DEF INC TAX 287258	DTA 705.454 Reg Lia - UT Property Ins Re	UT	709	-	-	-	709	-	-	-	
1901000	ACCUM DEF INC TAX 287259	DTA 705.455 Reg Lia - WY Property Ins Re	WYP	226	-	-	-	226	-	-	-	
1901000	ACCUM DEF INC TAX 287270	Valuation Allowance for DTA	SO	(516)	(11)	(140)	(40)	(68)	(227)	(30)	(0)	
1901000	ACCUM DEF INC TAX 287271	DTA 705.336 RL - Sale of RECs - UT	OTHER	478	-	-	-	-	-	-	478	
1901000	ACCUM DEF INC TAX 287272	DTA 705.337 RL - Sale of RECs - WY	OTHER	180	-	-	-	-	-	-	180	
1901000	ACCUM DEF INC TAX 287274	DTA 705.261 Reg Liab-Sale of RECs-OR	OTHER	55	-	-	-	-	-	-	55	
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	7	126	37	77	222	32	0	
1901000	ACCUM DEF INC TAX 287299	DTA 705.265 Reg Liab-OR Energy Conservat	OTHER	687	-	-	-	-	-	-	687	
1901000	ACCUM DEF INC TAX 287302	DTA-610.114 PMI EITF 04-06 PRE STRIPPING	SE	1,134	16	284	84	175	502	73	0	
1901000	ACCUM DEF INC TAX 287304	DTA 610.146 OR REG ASSET/LIAB CONS	OR	(111)	-	(111)	-	-	-	-	-	
1901000	ACCUM DEF INC TAX 287323	DTA 505.400 Bonus Liab. Elec.-Cash Basis	SO	143	3	39	11	19	63	8	0	
1901000	ACCUM DEF INC TAX 287324	DTA 720.200 Deferred Comp. Accrual - Cas	SO	1,956	43	531	150	257	859	114	0	
1901000	ACCUM DEF INC TAX 287326	DTA 720.500 Severance Accrual - Cash Ba	SO	848	19	231	65	112	373	50	0	
1901000	ACCUM DEF INC TAX 287327	DTA 720.300 Pension/Retirement Accrual -	SO	396	9	108	30	52	174	23	0	
1901000	ACCUM DEF INC TAX 287332	DTA 505.600 Vacation Accrual-Cash Basis	SO	8,479	187	2,304	651	1,115	3,725	495	2	
1901000	ACCUM DEF INC TAX 287337	DTA 715.105 MCI F.O.G. WIRE LEASE	SG	503	7	131	39	71	223	30	0	
1901000	ACCUM DEF INC TAX 287338	DTA415.110 Def Reg Asset-Transmission Sr	SG	490	7	128	38	70	218	29	0	
1901000	ACCUM DEF INC TAX 287340	DTA 220.100 Bad Debts Allowance - Cash B	BADDEBT	4,687	96	2,273	690	34	1,342	253	-	
1901000	ACCUM DEF INC TAX 287341	DTA 910.530 Injuries & Damages Accrual -	SO	63,041	1,390	17,130	4,839	8,288	27,698	3,683	13	
1901000	ACCUM DEF INC TAX 287370	DTA 425.215 Unearned Joint Use Pole Cont	SNPD	94	3	25	6	9	46	5	-	
1901000	ACCUM DEF INC TAX 287371	DTA 930.100 Oregon BETC Credits	SG	902	13	235	71	128	400	54	0	
1901000	ACCUM DEF INC TAX 287389	DTA 610.145 RL - DSM	OTHER	990	-	-	-	-	-	-	990	
1901000	ACCUM DEF INC TAX 287414	DTA 505.700 RT BONUS	SO	6	0	2	0	1	2	0	0	
1901000	ACCUM DEF INC TAX 287415	DTA 205.200 M&S INV	SNPD	597	21	158	38	57	291	32	-	
1901000	ACCUM DEF INC TAX 287417	DTA 605.710 ACCRUED FINAL RECLAMATION	OTHER	631	-	-	-	-	-	-	631	
1901000	ACCUM DEF INC TAX 287418	DTA 705.240 Calif Alt. Rate for Energy P	OTHER	106	-	-	-	-	-	-	106	
1901000	ACCUM DEF INC TAX 287430	DTA 505.125 Accrued Royalties	SE	3,601	51	903	266	556	1,594	231	1	
1901000	ACCUM DEF INC TAX 287437	DTA Net Operating Loss Carryforwrd-State	SO	66,982	1,477	18,201	5,142	8,806	29,429	3,913	14	
1901000	ACCUM DEF INC TAX 287441	DTA 605.100 Trojan Decom Cost-Regulatory	TROJD	1,299	19	336	101	187	576	79	0	
1901000	ACCUM DEF INC TAX 287449	DTA Federal Detriment of State NOL	SO	(14,100)	(311)	(3,831)	(1,082)	(1,854)	(6,195)	(824)	(3)	
1901000	ACCUM DEF INC TAX 287460	DTA 720.800 FAS 158 Pension Liability	SO	18,300	404	4,973	1,405	2,406	8,040	1,069	4	
1901000	ACCUM DEF INC TAX 287473	DTA 705.270 Reg Liab	OTHER	277	-	-	-	-	-	-	277	
1901000	ACCUM DEF INC TAX 287474	DTA 705.271 Reg Liab	OTHER	133	-	-	-	-	-	-	133	
1901000	ACCUM DEF INC TAX 287475	DTA 705.272 Reg Liab	OTHER	59	-	-	-	-	-	-	59	
1901000	ACCUM DEF INC TAX 287476	DTA 705.273 Reg Liab	OTHER	1,307	-	-	-	-	-	-	1,307	
1901000	ACCUM DEF INC TAX 287477	DTA 705.274 Reg Liab	OTHER	31	-	-	-	-	-	-	31	
1901000	ACCUM DEF INC TAX 287478	DTA 705.275 Reg Liab	OTHER	161	-	-	-	-	-	-	161	
1901000	ACCUM DEF INC TAX 287479	DTA 105.221 Saf Har	SG	0	0	0	0	0	0	0	0	
1901000	ACCUM DEF INC TAX 287482	DTA 205.025 PMI Fuel Cost Adjustment	SE	985	14	247	73	152	436	63	0	
1901000	ACCUM DEF INC TAX 287486	DTA 415.926 RL-Depreciation Decrease-OR	OTHER	1,636	-	-	-	-	-	-	1,636	
1901000	ACCUM DEF INC TAX 287487	DTA 415.927 RL-Depreciation Decrease-WA	WA	(0)	-	-	(0)	-	-	-	-	
1901000	ACCUM DEF INC TAX 287681	DTL 920.110 BRIDGER EXTRACTION TAXES PAY	SE	2,282	32	572	168	352	1,010	147	1	
1901000	ACCUM DEF INC TAX 287706	DTL 610.100 COAL MINE DEVT PMI	SE	(506)	(7)	(127)	(37)	(78)	(224)	(32)	(0)	
1901000	ACCUM DEF INC TAX 287720	DTL 610.100 PMI DEVT COST AMORT	SE	(264)	(4)	(66)	(19)	(41)	(117)	(17)	(0)	
1901000	ACCUM DEF INC TAX 287722	DTL 505.510 PMI VAC ACCRUAL	SE	229	3	57	17	35	101	15	0	
1901000	ACCUM DEF INC TAX 287723	DTL 205.411 PMI SEC. 263A	SE	(405)	(6)	(102)	(30)	(63)	(179)	(26)	(0)	
1901000	ACCUM DEF INC TAX 287726	DTL PMI PP&E	SE	(6,854)	(97)	(1,718)	(506)	(1,058)	(3,033)	(440)	(2)	
1901000	ACCUM DEF INC TAX 287735	DTL 910.905 PMI COST DEPLETION	SE	(496)	(7)	(124)	(37)	(77)	(220)	(32)	(0)	
1901000	ACCUM DEF INC TAX 287937	DTA 505.601 PMI - Sick Leave Accrual	SE	9	0	2	1	1	4	1	0	
1901000	ACCUM DEF INC TAX 287938	DTA 205.205 Inventory Reserve - PMI	SE	652	9	163	48	101	288	42	0	
1901000	ACCUM DEF INC TAX 287970	DTL 415.815 Insurance Rec Accruals	SO	(28,336)	(625)	(7,700)	(2,175)	(3,725)	(12,450)	(1,655)	(6)	
<b>1901000 Total</b>				<b>593,847</b>	<b>12,650</b>	<b>143,129</b>	<b>52,973</b>	<b>85,442</b>	<b>240,397</b>	<b>31,250</b>	<b>38</b>	<b>27,968</b>
1901090	FAS109 DEF TAX ASS 287374	DTA 100.105 FAS 109 Deferred Tax Liabli	WA	806	-	-	806	-	-	-	-	



Deferred Income Tax Balance (Actuals)  
 Year End: 06/2021  
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 (Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
<b>1901090 Total</b>			<b>806</b>	-	-	<b>806</b>	-	-	-	-	-
2811000	AC DEF TAX-ACCL AM 287960	DTL 105.128 Accel Depr Pollution Cntrl F	SG	(148,004)	(2,172)	(38,585)	(11,602)	(21,007)	(65,706)	(8,889)	(43)
<b>2811000 Total</b>				<b>(148,004)</b>	<b>(2,172)</b>	<b>(38,585)</b>	<b>(11,602)</b>	<b>(21,007)</b>	<b>(65,706)</b>	<b>(8,889)</b>	<b>(43)</b>
2820000	AC DEF INCTX-PROPT 287704	DTL 105.143/165 Basis Diff - Intangibles	SNP	(962)	(20)	(246)	(72)	(126)	(440)	(57)	(0)
<b>2820000 Total</b>				<b>(962)</b>	<b>(20)</b>	<b>(246)</b>	<b>(72)</b>	<b>(126)</b>	<b>(440)</b>	<b>(57)</b>	<b>(0)</b>
2821000	AC DEF TAX-UTILITY 286605	DTL 105.136 PP&E	DITBAL	(384)	(8)	(94)	(24)	(56)	(171)	(23)	(1)
2821000	AC DEF TAX-UTILITY 287221	DTA 415.933 RL Contra-Carbon Decomm-ID	IDU	(298)	-	-	-	-	-	(298)	-
2821000	AC DEF TAX-UTILITY 287222	DTA 415.934 RL Contra-Carbon Decomm-UT	UT	2,096	-	-	-	-	2,096	-	-
2821000	AC DEF TAX-UTILITY 287223	DTA 415.935 RL Contra-Carbon Decomm-WY	WYP	0	-	-	-	0	-	-	-
2821000	AC DEF TAX-UTILITY 287301	DTA 105.471 UT Klamath Relicensing	OTHER	8,681	-	-	-	-	-	-	8,681
2821000	AC DEF TAX-UTILITY 287605	DTL PP&E Powertax	DITBAL	(2,745,860)	(60,091)	(672,825)	(168,945)	(400,572)	(1,225,477)	(162,429)	(5,698)
2821000	AC DEF TAX-UTILITY 287607	DTL PMI PP&E	SE	(2,610)	(37)	(654)	(193)	(403)	(1,155)	(168)	(1)
2821000	AC DEF TAX-UTILITY 287608	DTL Safe Harbor Lease Cholla	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
2821000	AC DEF TAX-UTILITY 287766	DTL 610.100N Amort	SO	43	1	12	3	6	19	2	0
2821000	AC DEF TAX-UTILITY 287771	DTL 110.205 SRC tax depletion	SE	116	2	29	9	18	51	7	0
2821000	AC DEF TAX-UTILITY 287928	DTL 425.310 Hydro Relicensing Obligation	OTHER	(3,209)	-	-	-	-	-	-	(3,209)
<b>2821000 Total</b>				<b>(2,741,426)</b>	<b>(60,134)</b>	<b>(673,533)</b>	<b>(169,150)</b>	<b>(401,007)</b>	<b>(1,224,637)</b>	<b>(162,908)</b>	<b>(5,700)</b>
2831000	AC DEF IN TX UTIL 286891	DTL 415.943-RA-COV19 Bill Assist Prg-OR	OTHER	(1,140)	-	-	-	-	-	-	(1,140)
2831000	AC DEF IN TX UTIL 286892	DTL 415.944-RA-COV19 Bill Assist Prg-WA	OTHER	(363)	-	-	-	-	-	-	(363)
2831000	AC DEF IN TX UTIL 286893	DTL 415.755 RA-WA-Maj Mtc Exp-Colstrip	WA	(64)	-	-	(64)	-	-	-	-
2831000	AC DEF IN TX UTIL 286896	DTL 415.734 RA-Cholla Unrec Plant-CA	CA	(1,084)	(1,084)	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL 286898	DTL 415.736 RA-Cholla Unrec Plant-WY	WYP	(10,304)	-	-	-	(10,304)	-	-	-
2831000	AC DEF IN TX UTIL 286899	DTL 415.939 RA - Carbon Plt Dec/Inv-WY	WYP	129	-	-	-	129	-	-	-
2831000	AC DEF IN TX UTIL 286901	DTL 415.938 RA - Carbon Plt Dec/Inv-CA	CA	13	13	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL 286904	DTL 415.520 RA - WA Decoupling Mech	OTHER	(992)	-	-	-	-	-	-	(992)
2831000	AC DEF IN TX UTIL 286905	DTL 415.530 RA-ID 2017 Protocol-MSP Def	IDU	(74)	-	-	-	-	(74)	-	-
2831000	AC DEF IN TX UTIL 286908	DTL 210.201 Property Tax	GPS	(3,392)	(75)	(922)	(260)	(446)	(1,490)	(198)	(1)
2831000	AC DEF IN TX UTIL 286909	DTL 720.815 Post-Retirement Asset	SO	(4,241)	(94)	(1,152)	(326)	(558)	(1,863)	(248)	(1)
2831000	AC DEF IN TX UTIL 286910	DTL 415.200 RA-OR Transp Elect PilotPgm	OTHER	(904)	-	-	-	-	-	-	(904)
2831000	AC DEF IN TX UTIL 286911	DTL 415.430 - RA-Transp Elect Pilot-CA	OTHER	56	-	-	-	-	-	-	56
2831000	AC DEF IN TX UTIL 286912	DTL 415.431 - RA-Transp Elect Pilot-WA	OTHER	(98)	-	-	-	-	-	-	(98)
2831000	AC DEF IN TX UTIL 286913	DTL 415.720 RA-OR Community Solar	OTHER	(381)	-	-	-	-	-	-	(381)
2831000	AC DEF IN TX UTIL 286917	DTL 415.260 RA-Fire Risk Mitigation-CA	OTHER	(4,207)	-	-	-	-	-	-	(4,207)
2831000	AC DEF IN TX UTIL 286918	DTL 210.175 - Prepaid - FSA O&M - East	SG	(467)	(7)	(122)	(37)	(66)	(207)	(28)	(0)
2831000	AC DEF IN TX UTIL 286919	DTL 210.170 - Prepaid - FSA O&M - West	SG	(124)	(2)	(32)	(10)	(18)	(55)	(7)	(0)
2831000	AC DEF IN TX UTIL 286925	DTL 415.728 Contra RA-Cholla U4-OR	OR	152	-	152	-	-	-	-	-
2831000	AC DEF IN TX UTIL 286926	DTL 415.729 Contra RA-Cholla U4-UT	UT	383	-	-	-	-	383	-	-
2831000	AC DEF IN TX UTIL 286927	DTL 415.730 Contra RA-Cholla U4-WY	WYP	127	-	-	-	127	-	-	-
2831000	AC DEF IN TX UTIL 286928	DTL 415.833 RA-Pension Settlement-CA	OTHER	(116)	-	-	-	-	-	-	(116)
2831000	AC DEF IN TX UTIL 286929	DTL 415.841 RA-Emerg Svc Prgms-BS-CA	OTHER	152	-	-	-	-	-	-	152
2831000	AC DEF IN TX UTIL 286930	DTL 415.426-RA-2020 GRC-AMI Meter-OR	OTHER	(3,800)	-	-	-	-	-	-	(3,800)
2831000	AC DEF IN TX UTIL 286932	DTL 415.723-RA-Cholla U4-O&MDepr-ID	IDU	198	-	-	-	-	-	198	-
2831000	AC DEF IN TX UTIL 286933	DTL 415.645 RA-Oregon OCAT Expense Def	OTHER	(302)	-	-	-	-	-	-	(302)
2831000	AC DEF IN TX UTIL 287569	DTL 720.800 FAS 158 Pension Liability	SO	(2,045)	(45)	(556)	(157)	(269)	(899)	(119)	(0)
2831000	AC DEF IN TX UTIL 287570	DTL 415.701 CA Deferred Intervenor Fundi	OTHER	(37)	-	-	-	-	-	-	(37)
2831000	AC DEF IN TX UTIL 287571	DTL 415.702 Reg Asset-Lake Side Liq. Dam	WYU	(176)	-	-	-	(176)	-	-	-
2831000	AC DEF IN TX UTIL 287576	DTL 430.110 REG ASSET RECLASS	OTHER	(990)	-	-	-	-	-	-	(990)
2831000	AC DEF IN TX UTIL 287590	DTL 415.840 Reg Asset - Deferred OR Ind	OTHER	(9)	-	-	-	-	-	-	(9)
2831000	AC DEF IN TX UTIL 287591	DTL 415.301 Environmental Clean-up Accrl	WA	595	-	-	595	-	-	-	-
2831000	AC DEF IN TX UTIL 287593	DTL 415.874 Deferred Net Power Costs-WY	OTHER	(1,863)	-	-	-	-	-	-	(1,863)
2831000	AC DEF IN TX UTIL 287596	DTL 415.892 Deferred Net Power Costs - I	OTHER	(5,179)	-	-	-	-	-	-	(5,179)
2831000	AC DEF IN TX UTIL 287597	DTL 415.703 Goodnoe Hills Liquidation Da	WYP	(65)	-	-	-	(65)	-	-	-
2831000	AC DEF IN TX UTIL 287601	DTL 415.677 RA Pref Stock Redemption WA	OTHER	(9)	-	-	-	-	-	-	(9)
2831000	AC DEF IN TX UTIL 287614	DTL 430.100 Weatherization	OTHER	(48,828)	-	-	-	-	-	-	(48,828)
2831000	AC DEF IN TX UTIL 287634	DTL 415.300 Environmental Clean-up Accru	SO	(28,670)	(632)	(7,791)	(2,201)	(3,769)	(12,597)	(1,675)	(6)
2831000	AC DEF IN TX UTIL 287639	DTL 415.510 WA Disallowed Colstrip 3-Wri	WA	(0)	-	-	(0)	-	-	-	-
2831000	AC DEF IN TX UTIL 287640	DTL 415.680 Deferred Intervenor Funding	OTHER	(566)	-	-	-	-	-	-	(566)





Deferred Income Tax Balance (Actuals)  
 Year End: 06/2021  
 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 287647	DTL 425.100 IDAHO DEFERRED REGULATORY E	IDU	(25)	-	-	-	-	(25)	-	-
2831000	AC DEF IN TX UTIL 287653	DTL 425.250 TGS Buyout	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
2831000	AC DEF IN TX UTIL 287661	DTL 425.360 Hermiston Swap	SG	(637)	(9)	(166)	(50)	(90)	(283)	(38)	(0)
2831000	AC DEF IN TX UTIL 287662	DTL 210.100 Prepaid Taxes - OR PUC	OR	(1,003)	-	(1,003)	-	-	-	-	-
2831000	AC DEF IN TX UTIL 287664	DTL 210.120 Prepaid Taxes - UT PUC	UT	(1,705)	-	-	-	-	(1,705)	-	-
2831000	AC DEF IN TX UTIL 287665	DTL 210.130 Prepaid Taxes - ID PUC	IDU	(70)	-	-	-	-	(70)	-	-
2831000	AC DEF IN TX UTIL 287669	DTL 210.180 PRE MEM	SO	(1,001)	(22)	(272)	(77)	(132)	(440)	(59)	(0)
2831000	AC DEF IN TX UTIL 287675	DTL 740.100 Post Merger Loss-Reacq Debt	SNP	(762)	(16)	(195)	(57)	(100)	(348)	(45)	(0)
2831000	AC DEF IN TX UTIL 287708	DTL 210.200 PREPAID PROPERTY TAXES	GPS	(5,113)	(113)	(1,389)	(392)	(672)	(2,246)	(299)	(1)
2831000	AC DEF IN TX UTIL 287738	DTL 320.270 Reg Asset FAS 158 Pension	SO	(103,189)	(2,275)	(28,040)	(7,921)	(13,566)	(45,337)	(6,029)	(21)
2831000	AC DEF IN TX UTIL 287739	DTL 320.280 Reg Asset FAS 158 Post-Ret	SO	412	9	112	32	54	181	24	0
2831000	AC DEF IN TX UTIL 287747	DTL 705.240 CA Energy Program	OTHER	(0)	-	-	-	-	-	-	(0)
2831000	AC DEF IN TX UTIL 287770	DTL 120.205 TRAPPER MINE-EQUITY EARNINGS	OTHER	(906)	-	-	-	-	-	-	(906)
2831000	AC DEF IN TX UTIL 287772	DTL 505.800 State Tax Ded on Fed TR	OTHER	(0)	-	-	-	-	-	-	(0)
2831000	AC DEF IN TX UTIL 287781	DTL 415.870 Def CA	OTHER	(140)	-	-	-	-	-	-	(140)
2831000	AC DEF IN TX UTIL 287840	DTL 415.410 RA Energy West Mining	SE	(68,931)	(974)	(17,280)	(5,086)	(10,639)	(30,500)	(4,428)	(23)
2831000	AC DEF IN TX UTIL 287841	DTL 415.411 ContraRA DeerCreekAband CA	CA	637	637	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL 287842	DTL 415.412 ContraRA DeerCreekAband ID	IDU	657	-	-	-	-	-	657	-
2831000	AC DEF IN TX UTIL 287843	DTL 415.413 ContraRA DeerCreekAband OR	OR	2,330	-	2,330	-	-	-	-	-
2831000	AC DEF IN TX UTIL 287844	DTL 415.414 ContraRA DeerCreekAband UT	UT	227	-	-	-	-	227	-	-
2831000	AC DEF IN TX UTIL 287845	DTL 415.415 ContraRA DeerCreekAband WA	WA	2,525	-	-	2,525	-	-	-	-
2831000	AC DEF IN TX UTIL 287846	DTL 415.416 ContraRA DeerCreekAband WY	WYU	813	-	-	-	813	-	-	-
2831000	AC DEF IN TX UTIL 287848	DTL 320.281 RA Post-Ret Settlement Loss	SO	(595)	(13)	(162)	(46)	(78)	(261)	(35)	(0)
2831000	AC DEF IN TX UTIL 287849	DTL 415.424 ContraRA DeerCreekAband	SE	29,952	423	7,509	2,210	4,623	13,253	1,924	10
2831000	AC DEF IN TX UTIL 287850	DTL 415.425 Contra RA UMWA Pension	OTHER	1,168	-	-	-	-	-	-	1,168
2831000	AC DEF IN TX UTIL 287851	DTL 415.417 Contra RA UMWA Pension CA	OTHER	(0)	-	-	-	-	-	-	(0)
2831000	AC DEF IN TX UTIL 287855	DTL 415.421 Contra RA UMWA Pension WA	OTHER	1,991	-	-	-	-	-	-	1,991
2831000	AC DEF IN TX UTIL 287858	DTL 415.676 RA Pref Stock Redemption-WY	OTHER	(19)	-	-	-	-	-	-	(19)
2831000	AC DEF IN TX UTIL 287860	DTL 415.855 Reg Asset-CA-Jan10 Storm Cos	OTHER	(96)	-	-	-	-	-	-	(96)
2831000	AC DEF IN TX UTIL 287861	DTL 415.857 Reg Asset-ID-Def Overburden	OTHER	(115)	-	-	-	-	-	-	(115)
2831000	AC DEF IN TX UTIL 287864	DTL 415.852 Powerdale Decom Cost Amort-I	IDU	(1)	-	-	-	-	(1)	-	-
2831000	AC DEF IN TX UTIL 287868	DTL 415.858 Reg Asset-WY-Def Overburden	WYP	(324)	-	-	-	(324)	-	-	-
2831000	AC DEF IN TX UTIL 287871	DTL 415.866 Reg Asset-OR Solar Feed-In T	OTHER	(1,317)	-	-	-	-	-	-	(1,317)
2831000	AC DEF IN TX UTIL 287882	DTL 415.876 Deferred Net Power Costs-OR	OTHER	(208)	-	-	-	-	-	-	(208)
2831000	AC DEF IN TX UTIL 287888	DTL 415.882 Def of Excess RECs WA	OTHER	(31)	-	-	-	-	-	-	(31)
2831000	AC DEF IN TX UTIL 287889	DTL 415.883 Def of Excess RECs WY	OTHER	(0)	-	-	-	-	-	-	(0)
2831000	AC DEF IN TX UTIL 287896	DTL 415.875 Def Net Power Cost - UT	OTHER	(18,772)	-	-	-	-	-	-	(18,772)
2831000	AC DEF IN TX UTIL 287897	DTL 425.400 RA - UT Klamath Relicensing	OTHER	(1,518)	-	-	-	-	-	-	(1,518)
2831000	AC DEF IN TX UTIL 287899	DTL 415.878 RA-UT Liq Damages	UT	(108)	-	-	-	-	(108)	-	-
2831000	AC DEF IN TX UTIL 287903	DTL 415.879 RA-Liq Damages N2-WY	WYP	(18)	-	-	-	(18)	-	-	-
2831000	AC DEF IN TX UTIL 287906	DTL 415.863 RA-UT Subscriber Solar Prog	UT	(477)	-	-	-	-	(477)	-	-
2831000	AC DEF IN TX UTIL 287907	DTL 210.185-Prepaid Aircraft Maint Cost	SG	(48)	(1)	(12)	(4)	(7)	(21)	(3)	(0)
2831000	AC DEF IN TX UTIL 287908	DTL 210.190 - Prepaid Water Rights	SG	(120)	(2)	(31)	(9)	(17)	(53)	(7)	(0)
2831000	AC DEF IN TX UTIL 287917	DTL 705.451 - RL - OR Property Ins Res	OR	(5,148)	-	(5,148)	-	-	-	-	-
2831000	AC DEF IN TX UTIL 287919	DTL 425.105 RA-OR Asset Sale Gain GB-NC	OTHER	(522)	-	-	-	-	-	-	(522)
2831000	AC DEF IN TX UTIL 287935	DTL 415.936 RA - Carbon Plt Decom/Inv	SG	(453)	(7)	(118)	(35)	(64)	(201)	(27)	(0)
2831000	AC DEF IN TX UTIL 287939	DTL 415.115 RA-UT STEP Pilot Program	OTHER	4,381	-	-	-	-	-	-	4,381
2831000	AC DEF IN TX UTIL 287942	DTL 430.112 Reg Asset - Other - Balance	OTHER	(1,940)	-	-	-	-	-	-	(1,940)
2831000	AC DEF IN TX UTIL 287971	DTL 415.868 RA UT Solar Incentive Prog	OTHER	(4,381)	-	-	-	-	-	-	(4,381)
2831000	AC DEF IN TX UTIL 287975	DTL 415.655 RA - CA GHG Allowances	OTHER	(55)	-	-	-	-	-	-	(55)
2831000	AC DEF IN TX UTIL 287977	DTL 415.885 RA-NONCURRENT RECLASS-OTHE	OTHER	(157)	-	-	-	-	-	-	(157)
2831000	AC DEF IN TX UTIL 287981	DTL 415.920 RA-Depreciation Increase-ID	IDU	(1,462)	-	-	-	-	(1,462)	-	-
2831000	AC DEF IN TX UTIL 287982	DTL 415.921 RA-Depreciation Increase-UT	UT	(315)	-	-	-	-	(315)	-	-
2831000	AC DEF IN TX UTIL 287983	DTL 415.922 RA-Depreciation Increase-WY	WYP	(1,087)	-	-	-	(1,087)	-	-	-
2831000	AC DEF IN TX UTIL 287985	DTL 415.924 RA-Carbon Unrec Plant - UT	UT	(596)	-	-	-	-	(596)	-	-
2831000	AC DEF IN TX UTIL 287986	DTL 415.925 RA-Carbon Unrec Plant - WY	WYP	0	-	-	-	0	-	-	-
2831000	AC DEF IN TX UTIL 287994	DTL 415.929 RA-Carbon Decomm-CA	CA	(135)	(135)	-	-	-	-	-	-



Deferred Income Tax Balance (Actuals)  
 Year End: 06/2021  
 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	287996	DTL 415.675 RA Pref Stock Redemption-UT	OTHER	(55)	-	-	-	-	-	-	-	(55)
2831000	AC DEF IN TX UTIL	287997	DTL 415.862 RA-CA Mobile Home Park Conv	OTHER	(54)	-	-	-	-	-	-	-	(54)
<b>2831000 Total</b>					<b>(297,197)</b>	<b>(4,422)</b>	<b>(54,287)</b>	<b>(11,370)</b>	<b>(36,720)</b>	<b>(85,959)</b>	<b>(12,074)</b>	<b>(44)</b>	<b>(92,321)</b>
<b>Grand Total</b>					<b>(2,565,819)</b>	<b>(53,498)</b>	<b>(623,522)</b>	<b>(134,821)</b>	<b>(364,691)</b>	<b>(1,124,083)</b>	<b>(150,744)</b>	<b>(5,750)</b>	<b>(58,882)</b>



**Investment Tax Credit Balance (Actuals)**

Year End: 06/2021

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	(115)	(2)	(30)	(9)	(16)	(51)	(7)	(0)	-
2551000	ACC DEF ITC - FED	285621	Accum Def ITC - Solar Arrays - 2014	SG	(78)	(1)	(20)	(6)	(11)	(35)	(5)	(0)	-
2551000	ACC DEF ITC - FED	285622	Accum Def ITC - Solar Battery	UT	(1,391)	-	-	-	-	(1,391)	-	-	-
2551000	ACC DEF ITC - FED	285623	Accum Def ITC - Solar Facility	UT	(633)	-	-	-	-	(633)	-	-	-
<b>2551000 Total</b>					<b>(2,217)</b>	<b>(3)</b>	<b>(50)</b>	<b>(15)</b>	<b>(27)</b>	<b>(2,110)</b>	<b>(12)</b>	<b>(0)</b>	-
2552000	ACC DEF ITC-IDAHO	285612	Acc Def Idaho ITC-ID situs ATL	IDU	(28)	-	-	-	-	-	(28)	-	-
<b>2552000 Total</b>					<b>(28)</b>	-	-	-	-	-	<b>(28)</b>	-	-
<b>Grand Total</b>					<b>(2,245)</b>	<b>(3)</b>	<b>(50)</b>	<b>(15)</b>	<b>(27)</b>	<b>(2,110)</b>	<b>(40)</b>	<b>(0)</b>	-

# **B20. CUSTOMER ADVANCES**



**Customer Advances (Actuals)**

Year End: 06/2021

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	(1,424)	-	(1,424)	-	-	-	-		
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	SG	(30,469)	(447)	(7,943)	(2,388)	(4,325)	(13,527)	(1,830)	(9)	-
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	UT	(116)	-	-	-	-	(116)	-	-	-
2520000	CUST ADV CONSTRUCT	210553	Transmission Payments Received - Capital	SG	(4,351)	(64)	(1,134)	(341)	(617)	(1,931)	(261)	(1)	-
2520000	CUST ADV CONSTRUCT	210556	NET METER FEES-REFUNDABLE	UT	(169)	-	-	-	-	(169)	-	-	-
2520000	CUST ADV CONSTRUCT	210556	NET METER FEES-REFUNDABLE	WA	(1)	-	-	(1)	-	-	-	-	-
2520000	CUST ADV CONSTRUCT	285460	Transm Intercon Deposits - w/3rd Party	SG	(67,579)	(992)	(17,618)	(5,298)	(9,592)	(30,002)	(4,059)	(20)	-
<b>2520000 Total</b>					<b>(104,109)</b>	<b>(1,502)</b>	<b>(28,120)</b>	<b>(8,028)</b>	<b>(14,534)</b>	<b>(45,744)</b>	<b>(6,150)</b>	<b>(30)</b>	<b>0</b>
<b>Grand Total</b>					<b>(104,109)</b>	<b>(1,502)</b>	<b>(28,120)</b>	<b>(8,028)</b>	<b>(14,534)</b>	<b>(45,744)</b>	<b>(6,150)</b>	<b>(30)</b>	<b>0</b>

**REDACTED**

Docket No. UE 399

Exhibit PAC/1003

Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**REDACTED**

**Exhibit Accompanying Direct Testimony of Sherona L. Cheung**

**PacifiCorp's Property Tax Estimation Procedure**

**March 2022**

**THIS ATTACHMENT IS CONFIDENTIAL IN ITS  
ENTIRETY AND IS PROVIDED UNDER SEPARATE  
COVER**

**REDACTED**

Docket No. UE 399

Exhibit PAC/1004

Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

---

**REDACTED**

**Exhibit Accompanying Direct Testimony of Sherona L. Cheung**

**Wage and Employee Benefits Wage Escalators**

**March 2022**



**THIS ATTACHMENT IS CONFIDENTIAL IN ITS  
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COVER**

**REDACTED**

Docket No. UE 399

Exhibit PAC/1005

Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**REDACTED**

**Exhibit Accompanying Direct Testimony of Sherona L. Cheung**

**IHS Markit Escalation Indices**

**March 2022**

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**REDACTED**

Docket No. UE 399

Exhibit PAC/1006

Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**REDACTED**

**Exhibit Accompanying Direct Testimony of Sherona L. Cheung**

**Transmission Wheeling - Facebook Support**

**March 2022**

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**REDACTED**

Docket No. UE 399

Exhibit PAC/1007

Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**REDACTED**

**Exhibit Accompanying Direct Testimony of Sherona L. Cheung**

**Bridger Mine Reclamation Support**

**March 2022**

**THIS ATTACHMENT IS CONFIDENTIAL IN ITS  
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COVER**

**REDACTED**

Docket No. UE 399

Exhibit PAC/1008

Witness: Sherona L. Cheung

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**REDACTED**

**Exhibit Accompanying Direct Testimony of Sherona L. Cheung**

**Regulatory Assets & Liabilities Adjustment Support**

**March 2022**



**THIS ATTACHMENT IS CONFIDENTIAL IN ITS  
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COVER**

Docket No. UE 399  
Exhibit PAC/1100  
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Direct Testimony of Robert M. Meredith**

**March 2022**

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**ATTACHED EXHIBITS**

Exhibit PAC/1101—Proposed Tariffs

Exhibit PAC/1102—Unbundled Results of Operations - Summary and Detail

Exhibit PAC/1103—Functionalized Oregon Results of Operations Report

Exhibit PAC/1104—Functional Factors

Exhibit PAC/1105—Ancillary Services Revenue Requirement

Exhibit PAC/1106—Oregon Marginal Cost of Service Study Summary

Exhibit PAC/1107—Unbundled Revenue Requirement Allocation

Exhibit PAC/1108—Oregon Marginal Cost of Service Study

Exhibit PAC/1109—Target Functionalized Revenues, Billing Determinants and Proposed  
Rates

Exhibit PAC/1110—Estimated Effect of Proposed Rates

Exhibit PAC/1111—Residential Basic Charge Calculation

Direct Testimony of Robert M. Meredith

1                                   **I.     INTRODUCTION AND QUALIFICATIONS**

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

4   A.     My name is Robert M. Meredith. My business address is 825 NE Multnomah Street,  
5       Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing and  
6       Tariff Policy.

7   **Q.     Briefly describe your education and professional experience.**

8   A.     I have a Bachelor of Science degree in Business Administration and a minor in  
9       Economics from Oregon State University. In addition to my formal education, I have  
10      attended various industry-related seminars. I have worked for the Company for  
11      17 years in various roles of increasing responsibility in the Customer Service,  
12      Regulation, and Integrated Resource Planning departments. I have over 11 years of  
13      experience preparing cost of service and pricing related analyses for all of the six  
14      states that PacifiCorp serves. In March 2016, I became Manager, Pricing and Cost of  
15      Service. In February 2022, I assumed my present title.

16                                   **II.    PURPOSE AND SUMMARY OF TESTIMONY**

17   **Q.     What are your responsibilities in these proceedings?**

18   A.     I am responsible for the Company's proposed revenue requirement for each of the  
19      unbundled service categories, the Company's functionalization procedures, the  
20      Oregon Marginal Cost Study and the design of the Company's proposed prices in this  
21      proceeding. The proposed tariffs incorporate the Company's proposed price increase  
22      and are designed consistent with the Commission's rules under Oregon  
23      Administrative Rule (OAR) 860-038-0200. I am sponsoring the Company's Oregon

1 electric tariff schedules submitted for approval in this filing. Exhibit PAC/1101  
2 contains the proposed tariffs.

3 **Q. Please summarize your testimony.**

4 A. The overall rate increase proposed by the Company in this case, including the effect  
5 of rebalancing the Rate Mitigation Adjustment (RMA) and eliminating the separate  
6 charge for the Oregon Corporate Activity Tax Recovery Adjustment (OCAT) (both  
7 discussed later in my testimony), is \$82.2 million or 6.6 percent. The Company is  
8 proposing a base rate spread that is consistent with the cost of service study in this  
9 case. The Company's rate spread proposes continued use of the RMA to achieve a  
10 rate increase on January 1, 2023, where no customer rate class will see a rate increase  
11 more than double the average percent increase.

12 For rate design, the Company proposes keeping the same unbundled rate  
13 structure amongst prices for all schedules, except residential. For residential  
14 customers, the Company proposes increasing the single-family basic charge from  
15 \$9.50 to \$12 per month and replacing the inverted block energy charge structure with  
16 seasonal rates where winter prices are lower than summer prices.

17 **III. UNBUNDLED CLASS REVENUE REQUIREMENTS**

18 **Q. Please identify Exhibit PAC/1102 and explain what it shows.**

19 A. Exhibit PAC/1102 shows the Company's proposed revenue requirement for each of  
20 the unbundled service categories required by OAR 860-038-0200: Generation (also  
21 referred to as Production), Transmission, Distribution, Ancillary Services, Consumer  
22 Services—Billing, Consumer Services—Metering, Consumer Services—Other, Retail  
23 Services, and Investment in Public Purposes.

1           No revenue requirement is shown for the Retail Services or Investment in  
2           Public Purposes categories. The Company separately accounts for the costs  
3           associated with unregulated retail activities and is not seeking regulatory cost  
4           recovery for these items. Public purpose revenues are collected under a separate  
5           tariff.

6   **Q.   How was the revenue requirement determined for each of the unbundled**  
7   **categories?**

8   A.   Rate base balances, revenues and expenses were either assigned or allocated to  
9           unbundled categories in accordance with Oregon regulations.<sup>1</sup> Traditional revenue  
10          requirement methodology, (i.e., recovery of costs plus a return on rate base), was then  
11          used to determine a revenue requirement for each category. Rate base balances,  
12          revenues and expenses are from PacifiCorp's Oregon Results of Operations Report, as  
13          prepared under the direction of Ms. Sherona L. Cheung. The application of  
14          PacifiCorp's proposed rate increase is shown on page 2 of Exhibit PAC/1102.

15   **Q.   Please identify Exhibit PAC/1103 and explain what it shows.**

16   A.   Page 1 of Exhibit PAC/1103 is the summary page from PacifiCorp's December 2021  
17          Functionalized Oregon Results of Operations Report (Functionalized Oregon Results  
18          of Operations Report) and is the basis for the unbundled revenue requirement in  
19          Exhibit PAC/1102. It separates the results of operations into the unbundled categories  
20          identified above.

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<sup>1</sup> See OAR 860-038-0200.

1 **Q. Please explain how the rate base balances, revenues and expenses in the**  
2 **Functionalized Oregon Results of Operations Report were apportioned among**  
3 **the unbundled categories.**

4 A. The detail of PacifiCorp's Functionalized Results of Operations Report by Federal  
5 Energy Regulatory Commission (FERC) account is found on pages 2 through 22 of  
6 Exhibit PAC/1103. The functionalization procedures in this case are consistent with  
7 those approved in Order 01-787 and implemented in Advice No. 01-020. Functional  
8 factors employed in the development of these results are provided in Exhibit  
9 PAC/1104.

10 **Q. How did PacifiCorp determine the revenue requirement for Ancillary Services?**

11 A. The revenue requirement for Ancillary Services was estimated by applying  
12 PacifiCorp's prices for Regulation and Frequency Response Service, Spinning  
13 Reserve Service, and Supplemental Reserve Service to the relevant billing  
14 determinants of PacifiCorp's total Oregon retail load. This is shown in Exhibit  
15 PAC/1105. The costs associated with providing these services are included in the  
16 Generation function. The estimated revenue for Ancillary Services is treated as an  
17 offsetting revenue credit against the Generation revenue requirement.

18 **Q. Please identify Exhibit PAC/1106.**

19 A. Exhibit PAC/1106 contains a summary from PacifiCorp's State of Oregon December  
20 2023 Marginal Cost Study (Marginal Cost Study). The Marginal Cost Study is  
21 described in more detail later in my testimony.

22 **Q. Please identify Exhibit PAC/1107 and explain what it shows.**

23 A. Page 1 of Exhibit PAC/1107 is the derivation of functionalized class revenue

1 requirements and a comparison with current revenues. This exhibit is based on the  
2 results of both the Functionalized Oregon Results of Operations Report and the  
3 Marginal Cost Study. Present class revenues are shown on line 1 and megawatt-hours  
4 (MWh) are shown on line 2. Full long-run marginal costs for each customer class,  
5 separated by function, are shown on lines 4 through 12. Lines 14 through 25 show  
6 each class' share of total marginal costs for each function as well as each class' share  
7 of revenue and MWh. Lines 28 through 40 show the assignment of functional  
8 revenue requirement. The total revenue requirement for each unbundled category, as  
9 determined earlier, is shown in the total column. The total for each function is then  
10 allocated to a particular customer class based on that class' share of total marginal  
11 cost for that function. For example, the residential class accounts for 43.20 percent of  
12 generation marginal costs and is assigned 43.20 percent of the generation revenue  
13 requirement. Regulatory and franchise fees are considered part of the distribution  
14 function; however, for the purpose of assigning cost responsibility, the fees have been  
15 broken out separately. Regulatory and franchise fees have been assigned on the basis  
16 of class revenue. Lines 42 through 50 compare the total revenue requirement by class  
17 to the present class revenues collected from base rates as shown on line 1.

18 **Q. Please explain what is shown on pages 2 and 3 of Exhibit PAC/1107.**

19 A. Pages 2 and 3 of Exhibit PAC/1107 provide a reconciliation between Operating  
20 Revenues and Target Revenue Requirement, as shown on page 1 of this exhibit, with  
21 those shown in Exhibits PAC/1102 and PAC/1103. Not all customer classes are  
22 included in the Marginal Cost Study. Page 2 of Exhibit PAC/1107 accounts for all



1 Oregon test period revenue sources. Page 3 accounts for all revenue sources included  
2 in the Target Revenue Requirement.

3 **IV. MARGINAL COST STUDY**

4 **Q. Please describe PacifiCorp's Marginal Cost Study that accompanies this filing.**

5 A. The Marginal Cost Study is found in Exhibit PAC/1108. This study shows, by  
6 customer class, PacifiCorp's marginal cost of resources required to produce one  
7 additional unit of electricity, or to add one additional customer. Exhibit PAC/1108  
8 contains a marginal cost and circuit model procedures narrative, various summary  
9 tables, and supporting calculations.

10 **Q. Is this Marginal Cost Study similar to studies the Company has previously filed?**

11 A. Yes. This study is similar to the cost of service study the Company presented in  
12 docket UE 374 (2021 Rate Case).

13 **Q. How are marginal costs calculated?**

14 A. One-year marginal costs include only changes in operating costs while 10-year and  
15 20-year marginal costs also include the cost of expanding facilities. The costs of  
16 these added facilities result in long-run costs that are higher than short-run costs.  
17 Short-run costs include only one year of generation energy costs and some billing  
18 costs. They do not include any demand-related generation, transmission or  
19 distribution costs. A detailed description of marginal cost procedures is included in  
20 pages 1 through 14 of Exhibit PAC/1108.

1 **Q. Please describe the marginal cost summary tables included in pages 15 through**  
2 **22 of Exhibit PAC/1108.**

3 A. Tables 1 and 2 of Exhibit PAC/1108 summarize the one-year, 10-year and 20-year  
4 marginal costs on a mills-per-kilowatt-hour (kWh) or dollars-per-customer basis.  
5 Table 3 summarizes the unit costs based on the results of the long-run (20-year)  
6 marginal cost study. Unit costs are shown for generation, transmission, distribution,  
7 and various customer service functional categories. Table 3 also includes energy  
8 usage, peak demand, and number of customers by customer class for the 12-month  
9 period ending December 31, 2023 test period. This information is used to calculate  
10 the annual long-run marginal costs by class shown at the bottom of Table 3.

11 **Q. Please explain how generation marginal costs are calculated.**

12 A. Marginal generation costs in this study are based on the Company's currently  
13 approved Oregon avoided cost calculations. New resource costs are based on the  
14 fixed and variable cost of a combined cycle combustion turbine, which operates as a  
15 base load unit. Recognizing that base load generation produces the dual products of  
16 capacity and energy, capacity costs are determined using the fixed costs of a simple  
17 cycle combustion turbine. Generation energy costs are calculated by combining the  
18 remaining fixed and all variable costs of the combined cycle turbine plus the marginal  
19 cost of Oregon's Renewable Portfolio Standard (RPS) compliance. The marginal cost  
20 of RPS compliance is based upon the forecast incremental cost of compliance  
21 multiplied by the RPS compliance obligation percentage in each year. The  
22 compliance obligation is 20 percent for 2023 to 2024, 27 percent for 2025 to 2029,  
23 35 percent for 2030 to 2034, 45 percent for 2035 to 2039, and 50 percent for 2040

1 and beyond. Marginal generation capacity and energy costs are summarized on  
2 Table 4 of Exhibit PAC/1108.

3 **Q. How are transmission costs calculated?**

4 A. Transmission costs are based on a five-year analysis of forecasted expenditures.  
5 Expenditures identified as growth-related are used to develop marginal transmission  
6 costs. All of these growth-related transmission investments, except bulk power lines,  
7 are classified entirely to demand. Bulk power lines are classified both to demand and  
8 energy in the same proportions as the long-run marginal costs of generation resources.  
9 Marginal transmission costs are summarized on Table 5 of Exhibit PAC/1108.

10 **Q. Please provide a general overview of how marginal distribution costs are**  
11 **determined.**

12 A. Table 6 of Exhibit PAC/1108 provides a unit cost summary by class and load size of  
13 marginal distribution costs. Distribution costs are classified into three components:  
14 (1) demand-related, shown in dollars per kilowatt (kW)/year; (2) commitment-related,  
15 shown in dollars per customer/year; and (3) billing-related, shown in dollars per  
16 customer/year. Commitment-related distribution costs consist of the costs of  
17 transformers, poles and conductors that are not determined by the level of demand  
18 customers place on the system. Demand-related distribution costs include additional  
19 costs of larger transformers, substations, poles and conductors with sufficient capacity  
20 to serve the level of demand a customer class places on the system.

21 **Q. Please describe how the marginal costs of distribution line transformers are**  
22 **calculated.**

23 A. Marginal transformer costs are calculated using a least squares regression analysis of

1 the current installed cost versus size of the Company's commonly installed  
2 transformers. Commitment and demand costs are separated by the nature of this  
3 statistical technique. The regression provides an intercept term, which represents the  
4 commitment costs, and a slope, which represents the demand cost per kW. The  
5 regression also identifies the additional costs of a three-phase transformer over a  
6 single-phase transformer.

7 **Q. Please describe how the marginal costs of distribution circuits are calculated.**

8 A. Marginal costs of distribution poles and wires are calculated using the Company's  
9 Distribution Circuit Model. The circuit model focuses on several key characteristics  
10 that influence distribution cost of service. Among these are customer density,  
11 customer size and usage characteristics, and customer location on the circuit. The  
12 hypothetical circuit is constructed with seven branches of equal length using the  
13 composite line statistics and current cost estimates for Oregon. Customer locations  
14 are based on actual customer distances from the substation. The results are  
15 segregated into commitment-related and demand-related costs for each customer  
16 class. A detailed description of the updated circuit model is also included in the  
17 marginal cost procedures on pages 5 through 14 of Exhibit PAC/1108.

18 **Q. How are substation marginal costs calculated?**

19 A. Marginal substation costs are determined using the per kW cost of substation  
20 additions being considered for a five-year period. The cost per kW is determined by  
21 dividing the growth-related distribution substation investment in the capital budget  
22 horizon by the related increase in substation capacity. Substation marginal costs are  
23 classified entirely to demand and are allocated to customer classes based on the

1 distribution peak load for each class weighted by the load of substations peaking in  
2 each month.

3 **Q. What is included in the service drop category?**

4 A. The service drop category includes the marginal cost of service drops with associated  
5 operation and maintenance (O&M). Current typical installed costs for service drops  
6 are determined for each customer load size.

7 **Q. What is included in the metering category?**

8 A. The metering category includes the marginal cost of metering equipment with  
9 associated O&M. Current typical installed metering costs are determined for each  
10 customer load size by analyzing service requirements, such as single- or three-phase  
11 service and voltage level. Meter O&M is based on historical expenditures.

12 **Q. What is included in the billing and customer service/other categories?**

13 A. This category includes the costs of billing, payment processing and debt recovery,  
14 meter reading expense, and all the remaining customer accounting and customer  
15 service activities. Marginal meter reading expense is assumed to be zero because  
16 Advance Metering Infrastructure has been deployed for almost all customers.  
17 Customer accounting and customer service expense are based on historical  
18 expenditures and are assigned to each customer class based on the various resources  
19 required to perform billing, collections, and customer service activities for different  
20 types of customers.

1       **V. ALLOCATION OF THE FUNCTIONALIZED REVENUE REQUIREMENT**

2       **Q. How is the Company proposing to allocate the functionalized revenue**  
3       **requirement across classes of customers in this proceeding?**

4       A. The Company is allocating the functionalized revenue requirement to classes  
5       consistent with the Commission’s Direct Access Rules. These rules indicate that  
6       “rates for any class of consumer must be based on the unbundled costs to serve that  
7       class.”<sup>2</sup> In this filing, the Company has allocated the revenue requirement to each  
8       rate schedule based on the results of the functionalized class cost of service study.  
9       The proposed rates for each rate schedule included in the cost of service study are  
10      targeted to collect the cost of service for that rate schedule in the test period.

11      Therefore, the proposed base rates for each class are based on the unbundled costs to  
12      serve that class.

13      **Q. Do you have an exhibit that summarizes the functionalized results of the cost of**  
14      **service study?**

15      A. Yes. Pages 1 and 2 of Exhibit PAC/1109 summarize the functionalized results of the  
16      cost of service study in column (4). This summary is provided at the level used to  
17      design rates. The cost of service for each rate schedule has been summarized into the  
18      following components: Transmission & Ancillary Services, System Usage,  
19      Distribution, Generation Energy Other Non-Net Power Costs (Non-NPC), and  
20      Generation Energy Net Power Costs (NPC).

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<sup>2</sup> OAR 860-038-0240(3)(b).

1 **Q. What is the purpose of including this summary of cost components for the target**  
2 **functionalized revenue requirement?**

3 A. The summary level for revenue requirement shown on pages 1 and 2 of Exhibit  
4 PAC/1109 summarizes the cost of service results into the target revenue requirement  
5 components used in rate design.

6 The process of unbundling the Company's proposed prices is consistent with  
7 the method the Company first implemented in docket UE 116. For each rate  
8 schedule, the functionalized costs are applied to rates as follows: distribution, billing,  
9 metering, and customer costs are included in each proposed delivery service  
10 schedule's Distribution rates; the FERC regulated transmission and ancillary services  
11 are included in each proposed delivery service schedule's Transmission & Ancillary  
12 Services rates; non-NPC generation costs are included in Schedule 200, Base Supply  
13 Service rates; and NPC are included in Schedule 201, Net Power Costs, Cost-Based  
14 Supply Service rates.

15 **Q. Have any adjustments been made to the functionalized revenue requirement by**  
16 **rate schedule resulting from the cost of service study?**

17 A. Yes. Consistent with past cases, the functionalized revenue requirement has been  
18 adjusted to remove the proposed changes to NPC collected through Schedule 201.  
19 Changes to Schedule 201 are implemented through the transition adjustment  
20 mechanism (TAM), which is a separate proceeding from this general rate case, and  
21 the Schedule 201 changes will be addressed in that proceeding. The modified cost of  
22 service results reflecting this adjustment to remove the NPC increase from the  
23 functionalized revenue requirement is shown on pages 1 and 2 of Exhibit PAC/1109.

1 This exhibit displays the target functionalized revenue requirement used in the design  
2 of rates proposed in this general rate case.

3 **Q. Do the Company's proposed rates collect the target functionalized revenues?**

4 A. Yes. The revenues calculated by multiplying the test period billing determinants by  
5 the proposed rates are summarized in column (6) on pages 1 and 2 of Exhibit  
6 PAC/1109. A direct comparison to the target functionalized revenues shown in  
7 column (5) of this exhibit shows that the calculated revenues equal the target revenues  
8 with the exception of small differences due to the rounding of rates. The detailed  
9 calculation of proposed revenues based on billing determinants and proposed rates is  
10 shown on pages 3 through 11 of Exhibit PAC/1109.

11 **Q. Have you prepared an exhibit showing the estimated effects of the prices  
12 proposed in this general rate case?**

13 A. Yes. Exhibit PAC/1110 shows the estimated effect of the Company's proposed prices.  
14 Table 1110-1 shows the effect of the proposed prices by delivery service rate schedule  
15 for the proposed net rate increase on January 1, 2023, of \$82.2 million which includes  
16 the impact of the \$4.5 million RMA rebalancing and the \$6.7 million related to the  
17 elimination of the separate OCAT (both discussed later in my testimony). This table  
18 shows the effect of the price changes on both base revenues and net revenues. Base  
19 revenues show the effect before the impacts of any adjustment tariffs. Net revenues  
20 include the effect of adjustment tariffs (discussed directly below), the OCAT and the  
21 RMA.

22 The adder columns in Table 1110-1 show revenues from adjustment tariff  
23 schedules (Schedules 104, 194, 195, 198, 203, 204, 207, and 299). The adder revenue



1 is added to base revenue to calculate net revenue including adjustment schedules.  
2 Table 1110-2 shows the calculation of the adjustment revenue included in the adder  
3 columns in Table 1110-1. These tables exclude the effects of pass-through adjustment  
4 schedules for Low Income Bill Payment Assistance Charge (Schedule 91), the  
5 Adjustment Associated with the Pacific Northwest Electric Power Planning and  
6 Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the  
7 System Benefits Charge (Schedule 291). Table 1110-3 shows the present and  
8 proposed rates for each adjustment schedule.

9 Beginning on page 4 of Exhibit PAC/1110 are the monthly billing  
10 comparisons for each of the major delivery service rate schedules showing the  
11 customer bill impacts of the proposed prices at various levels of usage. The monthly  
12 billing comparisons in Exhibit PAC/1110 show the expected rate increases for  
13 January 1, 2023, from proposed rates. The monthly billing comparisons also include  
14 the effects of all adjustment schedules including the pass-through adjustment  
15 schedules listed above.

16 **Q. What are the Company's rate spread objectives in this case?**

17 A. The Company's rate spread objectives in this case are to minimize price impacts on  
18 our customers while fairly reflecting cost of service and sending proper signals about  
19 increasing costs.

20 **Q. What is the Company's rate spread proposal in this case?**

21 A. Based on the cost of service results and in order to achieve the Company's rate spread  
22 objectives in this case, Table 1 below summarizes the Company's proposed net  
23 percentage price changes for the major rate schedule classes.

1

**Table 1**

Residential Schedule 4	<b>9.1%</b>
General Service	
Schedule 23/723 (0-30kW)	<b>9.5%</b>
Schedule 28/728 (31-200kW)	<b>0.0%</b>
Schedule 30/730 (201-999kW)	<b>0.0%</b>
Large General Service Schedules 47/747, 48/748 ( $\geq 1,000$ kW)	<b>5.9%</b>
Agricultural Pumping Service Schedule 41/741	<b>13.2%</b>
<u>Lighting Schedules</u>	<b>0.0%</b>
Overall	<b>6.6%</b>

2

Under the Company’s proposal, the rate change that takes effect January 1,

3

2023, will result in no customer rate schedule class receiving an increase greater than

4

double the average increase or 13.2 percent. The Company’s proposed rate spread

5

strikes a balance between moderating rate impacts on customers, while sending

6

proper price signals about increasing costs and minimizing subsidization across rate

7

schedule classes. As a result, the Company proposes revisions to the RMA to achieve

8

these goals.

9

**Q. Please describe the RMA.**

10

A. The RMA, Schedule 299, is designed to mitigate the impacts of changes in the

11

functionalized revenue requirement on net rates across rate schedules. Net rates are

12

the rates that customers pay once all tariff riders (including the RMA) are taken into

13

account. The RMA is designed to be revenue neutral overall at the time a general rate

14

case price change is implemented, resulting in RMA credits for some rate schedule

15

classes requiring rate mitigation with offsetting RMA charges for others. The RMA

16

was first implemented in docket UE 116 to transition to cost of service rates under

1 Senate Bill 1149. The Schedule 299 RMA tariff rider is included in customers' rates  
2 for delivery services in order to minimize the effect of the price change allocation  
3 across customer classes.

4 **Q. Besides mitigation of rate changes across rate schedules, what other factors**  
5 **contribute to the adjustment of the RMA in a general rate case?**

6 A. In each general rate case, the RMA must be rebalanced in order to achieve revenue  
7 neutrality so that the revenues from the RMA charges and the RMA credits are in  
8 balance. The present Schedule 299 RMA rates were designed to be revenue neutral in  
9 the calendar year 2021 test period from the Company's 2021 Rate Case; however, due  
10 to changes in rate schedule loads, present Schedule 299 RMA rates are not projected  
11 to produce revenue neutrality in the calendar year 2023 test period of this case. The  
12 present RMA rates result in RMA credits that exceed RMA charges by \$4.5 million  
13 for the 2023 test period loads (see Exhibit PAC/1110, Table 1110-2, Column 11,  
14 Row 18). Consistent with previous RMA revisions, the proposed RMA rates have  
15 been designed to be revenue neutral for the 2023 test period. As a result of this  
16 realignment, the proposed net rate increase in this case is \$4.5 million higher than the  
17 base revenue requirement increase.

18 **Q. Has the RMA required rebalancing in previous general rate cases?**

19 A. Yes. For example, in the 2021 Rate Case the RMA required a rebalancing adjustment  
20 of \$0.4 million.

21 **Q. Are there any other factors which affect the net increase proposed in this case?**

22 A. Yes. The costs of the OCAT are now proposed to be collected through base rates, as  
23 discussed in the testimony of Ms. Cheung. The Company proposes to eliminate the

1 separate adjustment Schedule 104 which currently collects OCAT costs from  
2 customers. This results in a net rate increase in this case that is \$6.7 million less than  
3 the base increase.

4 **Q. What is the combined effect of the RMA rebalancing and the elimination of the**  
5 **OCAT surcharge on the proposed increase in this case?**

6 A. The combined impact is a proposed net rate increase that is \$2.2 million less than the  
7 base revenue requirement increase (Exhibit PAC/1110, Table 1110-1).

8 **Q. What are the present and proposed RMA revenues and rates in this case?**

9 A. The present and proposed RMA revenues are shown in Exhibit PAC/1110, Table  
10 1110-2, columns (11) and (12). Present and proposed RMA rates are shown in  
11 Exhibit PAC/1110, Table 1110-3, columns (11) through (16).

12 **Q. What is the Company's RMA objective in this case?**

13 A. The Company's RMA objective in this case is to minimize rate schedule subsidization  
14 through the RMA while minimizing impacts on customers. To limit the increase for  
15 irrigation customers to roughly twice the average price change, the Company  
16 proposes increasing the RMA credit received by irrigation customers. The Company  
17 also proposes RMA credits for residential customers to limit the net increase to about  
18 1.4 times the average increase.

19 For Small General Service Schedule 23 and Large General Service Schedules  
20 47/747 and 48/748, the Company proposes to eliminate the RMA surcharges and  
21 credit rates in order to minimize cross-subsidization. The proposed January 1 net  
22 increase for Schedule 23 is 9.5 percent and for Schedules 47/747 and 48/748 is  
23 5.9 percent.



1 period—in this case, the 12 months ended June 2021. These historical billing  
2 determinants are summarized by class, rate schedule, and voltage level.

3 Finally, a full set of forecast billing determinants is developed using the  
4 historical base period data and the test period forecast. The forecast billing  
5 determinants are calculated based upon the ratio of historical bills and energy  
6 (temperature normalized) in the base period to the forecast bills and energy provided  
7 in the sales forecast.

8 **Q. Have you provided an exhibit showing proposed rates and the billing**  
9 **determinants used to design rates?**

10 A. Yes. Pages 3 through 11 of Exhibit PAC/1109 contain historical and forecast billing  
11 determinants along with present and proposed base rates.

12 **Q. Please summarize the rate design changes proposed by the Company.**

13 A. In this case, the Company is proposing to increase the single-family basic charge for  
14 residential customers from \$9.50 to \$12. The Company is also proposing to replace  
15 the present inverted block tier rate structure with a seasonal rate structure for  
16 residential customers.

17 For other rate schedules, the Company proposes to keep the same unbundled  
18 rate structures and general relationship amongst rates.

19 **A. Residential Rate Design**

20 **Q. Please explain the proposed tariffs for residential customers.**

21 A. Residential customers are served on Delivery Service Schedule 4. The Company  
22 proposes increasing the basic charge from its current level of \$9.50 per month to \$12  
23 for single-family dwellings. This change better reflects the fixed costs of serving

1 residential customers and more fairly apportion cost between fixed and volumetric  
2 charges. The Company also proposes to eliminate the inclining tier block structure  
3 and replace it with seasonal energy charges.

4 For residential customers, as well as for all classes of customers,  
5 Schedule 200, Base Supply Service, is proposed to reflect changes in the non-NPC  
6 generation revenue requirement as indicated in pages 1 and 2 of Exhibit PAC/1109.

7 **Q. Why is the Company proposing an increase in its basic charge for most**  
8 **residential customers?**

9 A. The Company's marginal cost of service study which I present as Exhibit PAC/1108  
10 shows on Table 3 that the annual marginal cost of billing- and commitment-related  
11 cost is \$346.20 or about 28.85 per month. At \$9.50, the Company's present basic  
12 charge falls far short of cost. Making movement towards a cost-based basic charge is  
13 important because this helps the Company keep energy more affordable for its  
14 customers. Given a fixed level of revenue to be collected from all residential  
15 customers, an increase in the basic charge will lower energy charges. Exhibit  
16 PAC/1111 shows a breakdown of the marginal cost of billing- and commitment-  
17 related cost for single-family and multi-family residential customers.

18 **Q. How does the Company's current and proposed basic charge compare to other**  
19 **utilities in Oregon?**

20 A. The Company's current and proposed basic charge compares very favorably to the  
21 basic charges of other Oregon electric utilities. The Company examined the  
22 residential rates of 15 other utilities, which includes the other two electric investor-  
23 owned utilities in the state and 13 publicly owned electric utilities with service

1 territory in close proximity to the Company's. Table 2 below shows those basic  
2 charges as well as an average for all 15 utilities.

3 **Table 2: Comparison of PacifiCorp's Current and Proposed Basic Charge to Other**  
4 **Oregon Electric Utilities**

<u>Utility</u>	<u>Residential Basic Charge</u>
Current Pacific Power	\$8.00 multi-family/\$9.50 single family
Proposed Pacific Power	\$8.00 multi-family/\$12.00 single family
Portland General Electric	\$11.00
Idaho Power	\$8.00
Central Electric Coop	\$23.77
Central Lincoln PUD	\$24.00
City of Ashland	\$16.25
City of Hermiston	\$18.50
City of Monmouth	\$10.83
Coos-Curry Electric Coop	\$28.38
Eugene Water and Electric Board	\$20.50
Hood River Electric Coop	\$22.50
Lane Electric Coop	\$31.50
Salem Electric	\$20.00
Springfield Utility Board	\$15.30
Tillamook PUD	\$29.00
Umatilla Electric Coop	\$22.00
Average	\$20.10

**Note** - Prices were those available from each utility's website  
as of December 6, 2021

5 The average basic charge of all 15 utilities examined is \$20.10 which is well above  
6 the Company's current basic charge of \$8 for multi-family and its proposed \$12 for  
7 single-family.

8 **Q. How are residential energy charges currently structured?**

9 A. Residential energy charges use what is called an inclining block or tiered rate



1 structure where energy usage up to a specific threshold per month receives a lower  
2 price and successive energy consumption is priced at a higher rate. Including all  
3 adjustment schedules, the first 1,000 kWh<sup>3</sup> in a month are 9.018 cents per kWh and  
4 all additional kWh are 11.147 cents per kWh.

5 **Q. Historically, why have inclining block structures been used for residential**  
6 **customers?**

7 A. The inclining block rate structure has been considered by some to be an effective tool  
8 for encouraging customers to save energy. The theory is that the first block covers  
9 some basic level of usage at a lower rate to help keep the overall bill affordable for  
10 customers and a second and possibly third block with a higher rate makes incremental  
11 energy usage more expensive. For a customer with usage in the higher tiers, making  
12 energy efficient choices like installing light-emitting diode lights will yield greater  
13 savings than would have been achieved under a flat energy charge rate design.

14 **Q. Is the inclining block structure still an appropriate rate design for residential**  
15 **customers?**

16 A. No, not in light of changes in the electric industry and the likelihood of further  
17 evolution in the energy landscape of the future. While well intentioned, tiered rates  
18 can result in unintended consequences, particularly as the electric industry evolves.  
19 Tiered rates are unfair, are not economically justified, and create perverse incentives.  
20 In addition, tiered rate structures can be a source of confusion for residential  
21 customers

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<sup>3</sup> The tier block threshold is prorated so that it is higher for billing periods longer than the average month and lower for billing periods that are shorter. For example, a 28-day cycle has a tier block threshold of 920 kWh and a 34-day cycle has a tier block threshold of 1,117 kWh.

1 **Q. How are tiered rates unfair?**

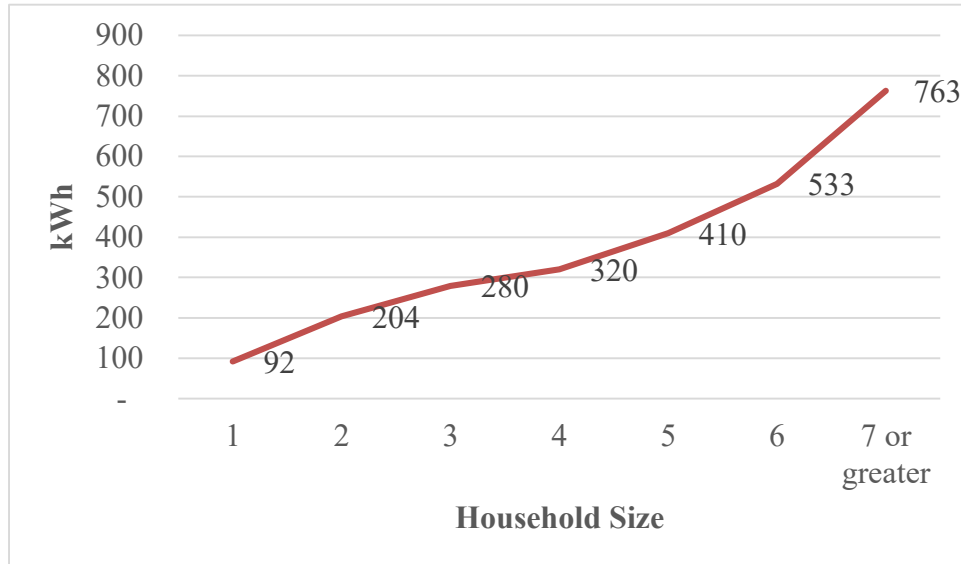
2 A. Charging higher prices for greater usage in a given month arbitrarily benefits some  
3 customers while harming others. Customers who heat their home with natural gas or  
4 a woodstove benefit and those who choose to heat their home with electricity, or  
5 otherwise do not have access to natural gas, pay more. A bustling, multi-generational  
6 household with a large number of people living under one roof pays a higher cost for  
7 energy usage and a person living alone in an apartment pays less. A customer who  
8 chooses to buy an electric vehicle and charge it from home likely falls into the second  
9 block and pays more per kWh to fuel the vehicle while another customer who keeps  
10 their internal combustion engine vehicle stays under the first block and pays less per  
11 kWh. Effectively, inclining block rates unfairly reward some customers and punish  
12 others, often for reasons outside the customer's control or in ways that incentivize  
13 behaviors that are at odds with changes in energy policy.

14 **Q. Do you have any evidence that larger households and customers who heat their**  
15 **homes with electricity end up with more usage priced at the higher cost second**  
16 **block?**

17 A. Yes. From examining the data from the Company's 2019 residential customer survey,  
18 the average usage that occurred in the second block was higher for larger households.  
19 Figure 1 below shows these differences:

1  
2

**Figure 1: Average Monthly Second Block Usage by Household Size from PacifiCorp’s 2019 Residential Customer Survey**



3 The Company’s survey results also showed that customers who used electricity as  
4 their primary fuel for heating their home had nearly three times greater usage in the  
5 second block. Table 3 below shows how usage compares for survey respondents who  
6 answered that they use electricity as the fuel for their main source of heating  
7 equipment and those who use other fuels:

8 **Table 3: Average Monthly Usage by Primary Heating Fuel from PacifiCorp’s**  
9 **2019 Residential Customer Survey**

Primary Heating Fuel	Average First Tier Usage (kWh)	Average Second Tier Usage (kWh)
Electricity	779	343
Other (natural gas, propane, oil, wood/pellets)	648	117

10 **Q. Please describe why tiered rates are not economically justified.**

11 A. There is no reason why after using 1,000 kWh in a given month that the next kWh  
12 consumed by a customer should cost more. The timing of energy consumption, both  
13 seasonally and during different hours, can affect the utility’s cost of providing kWh to  
14 the customer. The load factor, or the effective utilization of kWh consumption

1 relative to peak kW demand, can also change the average cost of providing energy.

2 However, there is nothing special about additional overall usage in a monthly billing  
3 period that makes it more expensive for the utility to produce that next kWh of  
4 electricity.

5 **Q. How do tiered rates create perverse incentives?**

6 A. Relative to a flat energy charge rate structure, inclining block prices encourage  
7 customers to switch fuels to natural gas. Avista Corporation, Cascade Natural Gas  
8 Corporation, and Northwest Natural, Oregon's three natural gas providers, do not use  
9 an inclining block rate structure for residential customers for volumetric gas  
10 consumption. In other words, the price for each therm that a natural gas customer in  
11 Oregon purchases is flat and does not become more expensive with greater usage  
12 within a monthly billing period. As the result of this disparity in rate designs,  
13 PacifiCorp's customers are sent a skewed message about the economics of using  
14 electricity to heat their homes relative to natural gas.

15 Another unfavorable result of tiered rates is that they make residential  
16 transportation electrification less attractive. While a customer can at this time still  
17 experience "fuel" savings with charging their electric vehicle at the higher second tier  
18 price relative to purchasing gasoline, if more costs get pushed into the customer's  
19 incremental cost of energy on the second tier the economic rationale to choose an  
20 electric car is weakened.

21 **Q. What does the Company propose for residential customers instead of the  
22 inclining tiered rate structure?**

23 A. In light of the inequities that the tiered rate structure presents and the need for

1 residential price signals to support the state's decarbonization goals, the Company  
2 proposes replacing the inclining block tiered rate structure with seasonal pricing. As  
3 opposed to tiered rates that make energy prices vary based upon monthly household  
4 usage, seasonal rates would make energy rates lower in winter months and higher in  
5 summer months. This structure for residential charges would better reflect the  
6 economics of energy consumption and would treat customers more fairly, regardless  
7 of household size or heating fuel used. Specifically, the Company proposes that the  
8 price for residential energy charges, including the impact of the concurrently filed  
9 TAM, would be 10.335 cents per kWh during the winter months of October through  
10 May and 12.264 cents per kWh during the summer months of June through October.  
11 Additionally, the Company proposes that the Schedule 98 Adjustment Associated  
12 with the Pacific Northwest Electric Power Planning and Conservation Act be  
13 modified to a flat 0.914 cents per kWh credit for all usage. With these changes, the  
14 net difference in between summer and winter energy charges of 1.9 cents per kWh  
15 would be very similar to the net price difference that currently exists between the first  
16 and second tier blocks of about 2.1 cents per kWh.

17 **Q. What is the cost justification for differentiating residential rates based upon**  
18 **season?**

19 A. PacifiCorp experiences its highest system loads during the summertime and  
20 wholesale market prices are often higher at this time. Examining the most recent  
21 monthly official market price curve used in the Company's TAM that was filed  
22 concurrently with this rate case, the average price at the Mid-Columbia hub between  
23 the months of June through September is forecast to be about 1.939 cents per kWh

1 higher during the 2023 rate effective period than during the months of October  
2 through May. The Company proposes using this same differential between its  
3 summer and winter residential energy charges.

4 **Q. How will seasonal rates send better price signals that encourage wise use of the**  
5 **system?**

6 A. By charging cost-based prices that vary by season of the year, the Company’s  
7 proposed rate structure will encourage customers to prioritize energy efficiency in the  
8 higher cost of service summer period. This could include installing a heat pump  
9 water heater or choosing a high efficiency air conditioner.

10 At the same time, the Company’s rates will no longer dis-incentivize heating  
11 homes with electricity as the current tiered rate structure does. However, even at the  
12 lower proposed winter energy price, customers will still be encouraged to choose  
13 efficient heating equipment but will be sent a more accurate price signal about the  
14 incremental cost of consumption.

15 **Q. Under this proposed seasonal rate structure, how would the economics of**  
16 **heating with electricity compare to heating with natural gas?**

17 A. Table 4 below shows how the cost of operating an efficient heat pump under the  
18 present second block energy charge and under the proposed winter energy charge  
19 would compare to operating an efficient natural gas furnace with service from  
20 Cascade Natural Gas:

**Table 4: Comparison of Residential Cost to Operate Heating Equipment**

Fuel Type	Unit Cost		Unit Cost per Therm	Appliance Type	Appliance Efficiency	(%, COP, or AFUE)	Cost Per Therm	Δ from Natural Gas
Electric (Pacific Power Current 2nd Tier Price)	\$0.11147	/kWh	\$3.266071	Heat Pump	300%	C.O.P.	\$1.09	22.3%
Electric (Pacific Power Proposed Winter Price)	\$0.10335	/kWh	\$3.028227	Heat Pump	300%	C.O.P.	\$1.01	13.4%
Electric (Pacific Power Proposed Winter Price)	\$0.10335	/kWh	\$3.028227	Baseboard	100	%	\$3.03	240.3%
Natural Gas (Cascade Natural Gas)	\$0.85753	/Therm	\$0.857530	Furnace	96%	AFUE	\$0.89	

1 Under existing rates, a Pacific Power customer in the second block would pay  
2 about 22.3 percent more to operate an efficient heat pump than natural gas. Under the  
3 proposed winter season price, a Pacific Power customer would pay about 13.4 percent  
4 more. Significantly, the cost for a Pacific Power customer paying the proposed  
5 winter price would still pay much more than natural gas to operate an inefficient  
6 baseboard heater.

7 **Q. Would the Company’s proposed changes to residential rates disproportionately**  
8 **impact customers experiencing lower than average income?**

9 A. I don’t believe they would. The Company examined the data from its 2019  
10 residential customer survey and found two trends that counterbalanced each other  
11 with respect to the Company’s proposed rate design. First, usage did tend to be  
12 moderately higher on average for higher income customers. Second, lower income  
13 customers tend to use a greater proportion of their usage during the winter months.

14 Table 5 below summarizes this finding:

15 **Table 5: Average Usage and Winter Usage Proportion by Income Level from**  
16 **PacifiCorp’s 2019 Residential Customer Survey**

<b>Income Level</b>	<b>Average Usage</b>	<b>Proportion of Usage that Occurs in Winter</b>
Less than \$50,000	882	72.5%
\$50,000 to \$74,999 <sup>1</sup>	924	70.5%
\$75,000 or more	982	69.4%

<sup>1</sup>Note - \$67,058 was the median household income in Oregon in 2019 per the United States Census Bureau, American Community Survey

17 To understand the potential impact of the proposed increase in the basic  
18 charge and the move from inclining block tiered rates to seasonal rates, the Company  
19 analyzed the usage information from respondents who had a full 12 months of usage.

1 The analysis showed that the bill impact, including the proposed change from the  
2 concurrently filed TAM, on average was very similar for different income levels.

3 Table 6 below summarizes this analysis:

4 **Table 6: Average Bill Impact by Income Level from PacifiCorp's 2019 Residential**  
5 **Customer Survey**

<b>Income Level</b>	<b>Average Monthly Bill Change</b>	<b>% Change</b>
Less than \$50,000	\$14.03	15.1%
\$50,000 to \$74,999 <sup>1</sup>	\$15.07	15.5%
\$75,000 or more	\$15.48	15.0%

<sup>1</sup>Note - \$67,058 was the median household income in Oregon in 2019 per the United States Census Bureau, American Community Survey

6 **Q. What change does the Company propose for the residential time of use Schedule**  
7 **6 pilot and for the time of use portfolio Schedule 210?**

8 A. For residential time of use pilot Schedule 6, the Company proposes keeping the same  
9 14.270 cent per kWh on-peak adder and the 3.790 cent per kWh off-peak credit, and  
10 applying them to the proposed flat seasonal prices for Schedule 4. For Schedule 210,  
11 the Company proposes modifying the seasons for the time of use hours and prices to  
12 be June through September for Summer and October through May for Winter, so that  
13 they are consistent with the periods for residential seasonal pricing.

14 Additionally for Schedule 210, the Company proposes to eliminate the  
15 monthly Portfolio Service Charge of \$1.50. This charge was originally intended to  
16 recover costs associated with the installation of a more expensive time of use meter.  
17 With customers now served with time of use capable advanced metering  
18 infrastructure meters, this charge is no longer necessary.



1 **Q. House Bill 2475 authorizes utilities to create differential rates and programs for**  
2 **low-income customers. What are the Company's plans to offer such a program?**

3 A. The Company intends to file for approval of a low-income bill assistance program  
4 soon after filing this rate case. The Company did not include a low-income bill  
5 assistance program proposal in this general rate case application because it hopes a  
6 program can be implemented sooner than the effective date for this rate case.

7 **B. Non-Residential Rate Design**

8 **Q. What does the Company propose for the rate design for non-residential**  
9 **customers?**

10 A. The Company is not proposing any changes to the underlying rate structures for non-  
11 residential customers. Prices were modified to collect the target revenue requirement  
12 and to track functionalized costs. Present and proposed rates for all schedules are  
13 detailed in Pages 3 through 11 of Exhibit PAC/1109.

14 **VII. CONCLUSION**

15 **Q. What is your recommendation for the Commission?**

16 A. I recommend that the Commission approve the Company's marginal cost of service  
17 study, rate spread, and rate design including its proposal to increase the basic charge  
18 for single-family residential customers to \$12 and replace the tiered structure to a  
19 seasonal structure for residential energy charges.

20 **Q. Does this conclude your direct testimony?**

21 A. Yes.

Docket No. UE 399  
Exhibit PAC/1101  
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Robert M. Meredith  
Proposed Tariffs**

**March 2022**

**Schedule No.**

<b>SUPPLY SERVICE</b>	
200	Base Supply Service
201	Net Power Costs – Cost-Based Supply Service
210	Portfolio Time-of-Use Supply Service
211	Portfolio Renewable Usage Supply Service
212	Portfolio Fixed Renewable Energy– Supply Service
213	Portfolio Habitat Supply Service
218	Interruptible Service Pilot
220	Standard Offer Supply Service
230	Emergency Supply Service
247	Partial Requirements Supply Service
276R	Large General Service/Partial Requirements Service – Economic Replacement Power Rider Supply Service
<b>ADJUSTMENTS</b>	
90	Summary of Effective Rate Adjustments
91	Low Income Bill Payment Assistance Fund
93	Independent Evaluator Cost Adjustment
94	Wildfire Mitigation and Vegetation Management Cost Recovery Adjustment
96	Property Sales Balancing Account Adjustment
97	Intervenor Funding Adjustment Cost Recovery Adjustment
98	Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act
101	Municipal Exaction Adjustment
103	Multnomah County Business Income Tax Recovery
194	Replaced Meter Deferred Amounts Adjustment (D)
195	Federal Tax Act Adjustment
198	Deer Creek Mine Closure Deferred Amounts Adjustment
202	Renewable Adjustment Clause – Supply Service Adjustment
203	Renewable Resource Deferral – Supply Service Adjustment
204	Oregon Solar Incentive Program Deferral – Supply Service Adjustment
205	TAM Adjustment for Other Revenues
206	Power Cost Adjustment Mechanism – Adjustment
207	Community Solar Start-Up Cost Recovery Adjustment
270	Renewable Energy Rider – Optional
271	Energy Profiler Online – Optional
272	Renewable Energy Rider – Optional Bulk Purchase Option
290	Public Purpose Charge
291	System Benefits Charge
294	Transition Adjustment
295	Transition Adjustment – Three-Year Cost of Service Opt-Out
296	Transition Adjustment – Five-Year Cost of Service Opt-Out
299	Rate Mitigation Adjustment



**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	\$12.00	(I)
Multi-Family Home Basic Charge, per month	\$8.00	

Three Phase Demand Charge, per kW demand	\$2.20	
Three Phase Minimum Demand Charge, per month	\$3.80	
Distribution Energy Charge, per kWh	4.435¢	(I)

**Transmission & Ancillary Services Charge**

Per kWh	0.918¢	(I)
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**System Usage Charge**

Schedule 200 Related, per kWh	0.066¢	(R)
T&A and Schedule 201 Related, per kWh	0.082¢	(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 210, Schedule 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule.

**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**

Consumer shall so arrange his wiring as to make possible the separate metering of the three-phase demand at a location adjacent to the kWh meter. If, on November 25, 1975, any present Consumer's wiring was arranged only for combined single and three-phase demand measurement, and continues to be so arranged, such demands will be metered and billed hereunder except that the first 10 kW of such combined demand will be deducted before applying demand charges for three phase service. No new combined demand installations will be allowed such a demand deduction

(continued)



**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	\$12.00	(I)
Multi-Family Home Basic Charge, per month	\$8.00	
Three Phase Demand Charge, per kW demand	\$2.20	
Three Phase Minimum Demand Charge, per month	\$3.80	
Distribution Energy Charge, per kWh	4.435¢	(I)

**Transmission & Ancillary Services Charge**

Per kWh	0.918¢	(I)
---------	--------	-----

**System Usage Charge**

Schedule 200 Related, per kWh	0.066¢	(R)
T&A and Schedule 201 Related, per kWh	0.082¢	(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 210, Schedule 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule.

**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.

**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 minimum monthly 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.



**PILOT FOR RESIDENTIAL TIME-OF-USE SERVICE  
DELIVERY SERVICE**

**Available**

In all territory served by the Company in the State of Oregon.

**Applicable**

To Residential Consumers otherwise receiving Delivery Service under Schedule 4, in conjunction with Supply Service Schedule 201. Service under this pilot will be limited to approximately twenty-five thousand (25,000) metered points of delivery.

**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 4.

**Distribution Charge**

Single Family Home Basic Charge, per month	\$12.00	(I)
Multi-Family Home Basic Charge, per month	\$8.00	
Three Phase Demand Charge, per kW demand	\$2.20	
Three Phase Minimum Demand Charge, per month	\$3.80	
Distribution Energy Charge, per kWh	4.435¢	(I)

**Transmission & Ancillary Services Charge**

Per kWh	0.918¢	(I)
---------	--------	-----

**System Usage Charge**

Schedule 200 Related, per kWh	0.066¢	(R)
T&A and Schedule 201 Related, per kWh	0.082¢	(I)

**Supply Service Options**

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall pay the applicable rates under Supply Service 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.

**On- and Off-Peak Definitions**

On-Peak Period	All days 5 p.m. to 9 p.m.
Off-Peak Period	All other hours

(continued)



**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.

<u>Type of Lamp</u>	<u>LED Equivalent Lumens</u>	<u>Monthly kWh</u>	<u>Rate Per Lamp</u>	
Level 1	0-5,000	19	\$7.04	(R)
Level 2	5,001-12,000	34	\$8.11	(R)
Level 3	12,001+	57	\$9.63	(R)

**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](http://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)



**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.

<u>Distribution Charge</u>	<u>Delivery Voltage</u>		
	<u>Secondary</u>	<u>Primary</u>	
Basic Charge			
Single Phase, per month	\$17.35	\$17.35	
Three Phase, per month	\$25.90	\$25.90	
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW Load Size	\$1.65	\$1.65	(I)(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	\$5.51	\$5.44	(I)(I)
Distribution Energy Charge, per kWh	4.109¢	4.045¢	(I)(I)
Reactive Power Charge, per kvar	\$0.65	\$0.60	
<u>Transmission &amp; Ancillary Services Charge</u>			
Per kWh	0.780¢	0.768¢	(I)(I)
<u>System Usage Charge</u>			
Schedule 200 Related, per kWh	0.064¢	0.063¢	(I)(I)
T&A and Schedule 201 Related, per kWh	0.077¢	0.076¢	(I)(I)

**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)





**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.

	<u>Delivery Voltage</u>		
	Secondary	Primary	
<b><u>Distribution Charge</u></b>			
Basic Charge			
Load Size ≤50 kW, per month	\$ 19.00	\$ 17.00	(R)
Load Size 51-100 kW, per month	\$ 34.00	\$ 30.00	(R)(R)
Load Size 101 - 300 kW, per month	\$ 82.00	\$ 70.00	(R)(R)
Load Size > 300 kW, per month	\$117.00	\$100.00	(R)(R)
Load Size Charge			
≤50 kW, per kW Load Size	\$ 1.20	\$ 1.00	(R)
51 - 100 kW, per kW Load Size	\$ 0.95	\$ 0.80	(R)
101 – 300 kW, per kW Load Size	\$ 0.55	\$ 0.50	(R)
> 300 kW, per kW Load Size	\$ 0.35	\$ 0.25	(R)
Demand Charge, per kW	\$ 3.95	\$ 3.42	(R)(R)
Distribution Energy Charge, per kWh	0.395¢	0.034¢	(R)(R)
Reactive Power Charge, per kvar	\$ 0.65	\$ 0.60	
<b><u>Transmission &amp; Ancillary Services Charge</u></b>			
Per kW	\$ 2.13	\$ 1.67	(R)(R)
<b><u>System Usage Charge</u></b>			
Schedule 200 Related, per kWh	0.069¢	0.077¢	(I)(I)
T&A and Schedule 201 Related, per kWh	0.083¢	0.091¢	(I)(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)



**OREGON  
SCHEDULE 29**

**PILOT FOR GENERAL SERVICE TIME-OF-USE  
DELIVERY SERVICE**

**Available**

In all territory served by the Company in the State of Oregon.

**Applicable**

To 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. Participation in this schedule will be limited to 100 metered points of delivery on a first-come, first served basis. New customer connections made on or after January 1, 2021 will be exempt from the participation cap and will be allowed to take service under this schedule if otherwise eligible.

(T)

**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	\$36.00	(R)
Distribution Energy Charge		
First 50 kWh per kW demand, per kWh	18.559¢	(R)
All Additional kWh, per kWh	-1.308¢	(R)

**Transmission & Ancillary Services Charge**

Per kWh	0.713¢	(R)
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**System Usage Charge**

Schedule 200 Related, per kWh	0.069¢	(I)
T&A and Schedule 201 Related, per kWh	0.083¢	(I)

**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.

**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)



**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**

	<b><u>Delivery Voltage</u></b>		
	<b>Secondary</b>	<b>Primary</b>	
Basic Charge			
Load Size ≤200 kW, per month	\$438.00	\$410.00	(R)(R)
Load Size 201 - 300 kW, per month	\$128.00	\$130.00	(R)(R)
Load Size > 300 kW, per month	\$339.00	\$338.00	(R)(R)
Load Size Charge			
≤200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	\$1.55	\$1.40	(R)(R)
> 300 kW, per kW Load Size	\$0.75	\$0.70	(R)(R)
Demand Charge, per kW	\$3.72	\$3.59	(R)(R)
Reactive Power Charge, per kvar	\$0.65	\$0.60	

**Transmission & Ancillary Services Charge**

Per kW	\$2.52	\$2.54	(I)
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**System Usage Charge**

Schedule 200 Related, per kWh	0.068¢	0.069¢	(I)(I)
T&A and Schedule 201 Related, per kWh	0.081¢	0.082¢	(I)(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)



**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**

	<b><u>Delivery Voltage</u></b>		
	<b>Secondary</b>	<b>Primary</b>	
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	\$490.00	\$480.00	(I)(I)
Three Phase Load Size > 300 kW	\$1,930.00	\$1,900.00	(I)(I)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	\$17.10	\$16.90	
Three Phase 51 - 300 kW, per kW Load Size	\$11.70	\$11.50	
Three Phase > 300 kW, per kW Load Size	\$7.20	\$7.10	
Single Phase, Minimum Charge	\$90.00	\$90.00	(I)(I)
Three Phase, Minimum Charge	\$140.00	\$140.00	(I)(I)
Distribution Energy Charge, per kWh	6.140¢	6.045¢	(I)(I)
Reactive Power Charge, per kVar	\$0.65	\$0.60	

**Transmission & Ancillary Services Charge**

Per kWh	0.678¢	0.668¢	(I)(I)
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**System Usage Charge**

Schedule 200 Related, per kWh	0.067¢	0.066¢	(I)(I)
T&A and Schedule 201 Related, per kWh	0.057¢	0.056¢	(R)(R)

**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)



**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.

<b><u>Distribution Charge</u></b>	<b><u>Delivery Voltage</u></b>			
	<b>Secondary</b>	<b>Primary</b>	<b>Transmission</b>	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	\$540.00	\$530.00	\$710.00	(R)(R)
Facility Capacity > 4,000 kW, per month	\$1,500.00	\$1,470.00	\$1,820.00	(R)(R)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	\$2.95	\$1.25	\$1.25	(I)(R)
> 4,000 kW, per kW Facility Capacity	\$0.80	\$0.85	\$1.05	
On-Peak Demand Charge, per kW	\$3.42	\$3.65	\$2.04	(R)(R)(R)
Reactive Power Charges				
Per kvar	\$0.65	\$0.60	\$0.55	
Per kVarh	\$0.0008	\$0.0008	\$0.0008	
<b><u>Reserves Charges</u></b>				
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)	
<b><u>Transmission &amp; Ancillary Services Charge</u></b>				
Per kW of On-Peak Demand	\$2.23	\$2.45	\$3.11	(R) (R)
<b><u>System Usage Charge</u></b>				
Schedule 200 Related, per kWh	0.068¢	0.065¢	0.062¢	(I)(I)(I)
T&A and Schedule 201 Related, per kWh	0.080¢	0.076¢	0.072¢	(I)(I)(I)

(continued)



**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**

	<b><u>Delivery Voltage</u></b>			
	<b>Secondary</b>	<b>Primary</b>	<b>Transmission</b>	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	\$540.00	\$530.00	\$710.00	(R)(R)
Facility Capacity > 4,000 kW, per month	\$1,500.00	\$1,470.00	\$1,820.00	(R)(R)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	\$2.95	\$1.25	\$1.25	(I)(R)
> 4,000 kW, per kW Facility Capacity	\$0.80	\$0.85	\$1.05	
On-Peak Demand Charge, per kW	\$3.42	\$3.65	\$2.04	(R)(R)(R)
Reactive Power Charge, per kvar	\$0.65	\$0.60	\$0.55	
<b><u>Transmission &amp; Ancillary Services Charge</u></b>				
Per kW of On-Peak Demand	\$2.77	\$2.99	\$3.65	(R) (R)

**System Usage Charge**

Schedule 200 Related, per kWh	0.068¢	0.065¢	0.062¢	(I)(I)(I)
T&A and Schedule 201 Related, per kWh	0.080¢	0.076¢	0.072¢	(I)(I)(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.

**Reactive Power Charge**

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the maximum measured kilowatt demand for the same month.

(continued)

**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	\$ 5.81	\$ 6.17	\$ 6.31	\$ 6.43	\$ 6.85	\$ 8.35	(R)
Functional Lighting - Customer Funded Conversion	\$ 3.14	\$ 3.33	\$ 3.46	\$ 3.54	\$ 3.80	\$ 4.65	(R)
Decorative Series	N/A	\$ 10.62	\$ 10.73	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.

**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)



**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.

<b>High Pressure Sodium Vapor</b>						
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	\$ 1.18	\$ 1.67	\$ 2.43	\$ 3.23	\$ 4.37	\$ 6.69

(R)

<b>Metal Halide</b>					
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	\$ 1.48	\$ 2.58	\$ 3.57	\$ 5.66	\$ 13.45

(R)

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.

<b>Non-Listed Luminaire</b>	<b>¢/kWh</b>
Energy Only Service	3.799

(R)

**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)



**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	4.090¢	(R)

**Transmission & Ancillary Services Charge**

per kWh	0.037¢	(R)
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**System Usage Charge**

Schedule 200 Related, per kWh	0.018¢	(R)
T&A and Schedule 201 Related, per kWh	0.018¢	

**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)



**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:

	<u>Delivery Voltage</u>			
	Secondary	Primary	Transmission	
<b>Transmission &amp; Ancillary Services Charge</b>				
Per kW of Daily Economic Replacement Power (ERP)				
On-Peak Demand per day	\$0.087	\$0.095	\$0.121	(R)
<b>Daily ERP Demand Charge</b>				
Per kW of Daily ERP On-Peak Demand	\$0.133	\$0.142	\$0.079	(R)(R)(R)

**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)



**ADJUSTMENT ASSOCIATED WITH THE PACIFIC NORTHWEST  
ELECTRIC POWER PLANNING AND CONSERVATION ACT**

All bills to qualifying residential and nonresidential customers shall have deducted an amount equal to the product of all kilowatt-hours of use multiplied by the following cents per kilowatt-hour:

0.914¢ per kWh

**Condition of Service**

The eligibility of affected Customers for the rate credit specified in this tariff is as provided by the Pacific Northwest electric Power Planning and Conservation Act, Public Law 96-501.

Eligible Customers with usage at or above 100,000 kWh per year must complete and submit to the Company a certificate verifying eligibility in order to receive the rate credit. Certificate forms are available on the Company's website at [www.pacificpower.net](http://www.pacificpower.net) under Oregon Regulatory Information. Consistent with the requirements of the Bonneville Power Administration, a federal agency, customers using electricity to aid in growing one or more Cannabis plants are not eligible for the rate credit specified in this tariff. If, in the course of doing business, a utility discovers that one of its existing customers is not eligible for the rate credit specified in this tariff, the customer will no longer receive the credit.

**Special Conditions**

In no instance shall a farm's total qualifying irrigation load for any billing period exceed 222,000 kWh. Under the Northwest Power Act, any farm may receive REP benefits for up to a maximum of 400 horsepower (HP)/month (222,000 kWh/month) of qualified irrigation/pumping load (the "REP Benefits Qualified Irrigation/Pumping Load Cap" or "Irrigation/Pumping Load Cap").

**OREGON CORPORATE ACTIVITY TAX  
RECOVERY ADJUSTMENT**

**Purpose**

To recover from Consumers in the State of Oregon the Oregon Corporate Activity Tax (OCAT) paid by the Company in accordance with HB 3427-A.

**Applicable**

To all bills for all Consumers whose electric service requirements are supplied by the Company in the State of Oregon.

**Balancing Account**

A balancing account will be maintained to accrue any difference between the Company's actual OCAT expense and the amount collected from Consumers through this adjustment rate. Any over- or under-collection of the OCAT expense will be considered when the OCAT Rate is periodically reviewed.

**Oregon Corporate Activity Tax Recovery Adjustment Rate**

The adjustment rate is:

0.54% of the total billed amount to the Consumer excluding the Low Income Bill Payment Assistance Fund (Schedule 91), the Adjustment Associated with the Pacific Northwest Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), the Energy Conservation Charge (Schedule 297) and separately stated state and local taxes.

The adjustment rate will be reviewed periodically and updated as necessary to collect the expected OCAT expense and to correct any over- or under-collection in the OCAT balancing account.

**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.

	<u>Delivery Service Schedule No.</u>	<u>Delivery Voltage</u>			
		<b>Secondary</b>	<b>Primary</b>	<b>Transmission</b>	
	4	Per Summer kWh	3.648¢		(D)
		Per Winter kWh	2.698¢		(N)
	5	Per Summer kWh	3.648¢		(D)
		Per Winter kWh	2.698¢		(N)
	6	Per Summer kWh	3.648¢		(D)
		Per Winter kWh	2.698¢		(N)
		For Schedules 4, 5 and 6, Summer is defined as months of June through September.			(N)
		Winter is defined as the months of October through May. Seasonal kilowatt-hours			(N)
		shall be prorated to the nearest whole kilowatt-hour based upon the number of whole			(N)
		days in the billing period falling within each season.			(N)
	23, 723	First 3,000 kWh, per kWh	2.957¢	2.911¢	(I)(I)
		All additional kWh, per kWh	2.195¢	2.161¢	(I)(I)
	28, 728	All kWh, per kWh	2.757¢	2.693¢	(I)(R)

(continued)

## BASE SUPPLY SERVICE

**Monthly Billing (continued)**

<u>Delivery Service Schedule No.</u>		<u>Delivery Voltage</u>			
		<b>Secondary</b>	<b>Primary</b>	<b>Transmission</b>	
29	All kWh, per kWh	2.757¢	2.757¢		(I)(I)
30, 730	Demand Charge, per kW	\$5.80	\$5.80		(I)(I)
	All kWh, per kWh	1.073¢	1.037¢		(R)(R)
	Demand shall be as defined in the Delivery Service Schedule				
41, 741	All kWh	2.666¢	2.625¢		(I)(I)
47/48,	Demand Charge, per kW of On-Peak Demand	\$1.66	\$1.74	\$1.77	(I)(I)(I)
747/748	Per kWh, On-Peak	2.266¢	2.216¢	2.190¢	(I)(I)(I)
	Per kWh, Off-Peak	2.266¢	2.216¢	2.190¢	(I)(I)(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	<u>Type of Lamp</u>	<u>LED Equivalent Lumens</u>	<u>Monthly kWh</u>	<u>Rate Per Lamp</u>	
	Level 1	0-5,500	19	\$0.73	(R)
	Level 2	5,501-12,000	34	\$1.32	(R)
	Level 3	12-001+	57	\$2.21	(R)

(continued)

**Monthly Billing (continued)**
Delivery Service Schedule No.

51, 751	<u>Type of Lamp</u>	<u>LED Equivalent Lumens</u>		<u>Monthly kWh</u>	<u>Rate per Lamp</u>	
	Level 1	0-3,500		8	\$0.30	(R)
	Level 2	3,501-5,500		15	\$0.57	
	Level 3	5,501-8,000		25	\$0.94	
	Level 4	8,001-12,000		34	\$1.27	
	Level 5	12,001-15,500		44	\$1.65	
	Level 6	15,501+		57	\$2.14	(R)
53, 753	<u>Types of Luminaire</u>	<u>Nominal rating</u>	<u>Watts</u>	<u>Monthly kWh</u>	<u>Rate Per Luminaire</u>	
	High Pressure Sodium	5,800	70	31	\$0.15	(R)
	High Pressure Sodium	9,500	100	44	\$0.21	
	High Pressure Sodium	16,000	150	64	\$0.30	
	High Pressure Sodium	22,000	200	85	\$0.40	
	High Pressure Sodium	27,500	250	115	\$0.54	
	High Pressure Sodium	50,000	400	176	\$0.83	
	Metal Halide	9,000	100	39	\$0.18	
	Metal Halide	12,000	175	68	\$0.32	
	Metal Halide	19,500	250	94	\$0.44	
	Metal Halide	32,000	400	149	\$0.70	
	Metal Halide	107,800	1,000	354	\$1.67	
	Non-Listed Luminaire, per kWh				0.473¢	
54, 754	Per kWh			0.610¢		(R)



**TAM ADJUSTMENT FOR OTHER REVENUES**
**Purpose**

This schedule adjusts rates for Other Revenues as authorized by Order No. 10-363.

**Applicable**

To all Residential Consumers and Nonresidential Consumers.

**Energy Charge**

The adjustment rate is listed below by Delivery Service Schedule and Direct Access Delivery Service Schedule.

	<u>Delivery Service Schedule No.</u>		<u>Delivery Voltage</u>			
			Secondary	Primary	Transmission	
4	Per kWh	0-1000 kWh	0.000¢			(R)
		> 1000 kWh	0.000¢			(R)
5	Per kWh	0-1000 kWh	0.000¢			(R)
		> 1000 kWh	0.000¢			(R)
For Schedules 4 and 5, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).						
6	Per kWh	All kWh	0.000¢			(R)
23, 723	First 3,000 kWh, per kWh		0.000¢	0.000¢		(R)
	All additional kWh, per kWh		0.000¢	0.000¢		(R)
28, 728	All kWh, per kWh		0.000¢	0.000¢		(R)

(continued)

## TAM ADJUSTMENT FOR OTHER REVENUES

**Energy Charge (continued)**

<u>Delivery Service Schedule No.</u>		<u>Delivery Voltage</u>			
		<u>Secondary</u>	<u>Primary</u>	<u>Transmission</u>	
29	All kWh, per kWh	0.000¢	0.000¢		(R)
30, 730	All kWh, per kWh	0.000¢	0.000¢		(R)
41, 741	All kWh, per kWh	0.000¢	0.000¢		(R)
47/48	Per kWh On-Peak	0.000¢	0.000¢	0.000¢	(R)
747/748	Per kWh, Off-Peak	0.000¢	0.000¢	0.000¢	(R)

For Schedule 47 and Schedule 48, 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. Off-Peak hours are all remaining hours.

15	<u>Type of Lamp</u>	<u>LED Equivalent Lumens</u>	<u>Monthly kWh</u>	<u>Rate per Lamp</u>	
	Level 1	0-5,000	19	\$0.00	(R)
	Level 2	5,001-12,000	34	\$0.00	(R)
	Level 3	12,001+	57	\$0.00	(R)

(continued)

## TAM ADJUSTMENT FOR OTHER REVENUES

**Energy Charge (continued)**
**Delivery Service Schedule No.**

51, 751	<u>Type of Lamp</u>	<u>LED Equivalent Lumens</u>	<u>Monthly kWh</u>	<u>Rate per Lamp</u>		
	Level 1	0-3,500	8	\$0.00		
	Level 2	3,501-5,500	15	\$0.00		
	Level 3	5,501-8,000	25	\$0.00	(R)	
	Level 4	8,001-12,000	34	\$0.00	(R)	
	Level 5	12,001-15,500	44	\$0.00	(R)	
	Level 6	15,501+	57	\$0.00	(R)	
53, 753	<u>Types of Luminaire</u>	<u>Nominal rating Watts</u>	<u>Monthly kWh</u>	<u>Rate Per Luminaire</u>		
	High Pressure Sodium	5,800	70	31	\$0.00	
	High Pressure Sodium	9,500	100	44	\$0.00	
	High Pressure Sodium	16,000	150	64	\$0.00	(R)
	High Pressure Sodium	22,000	200	85	\$0.00	(R)
	High Pressure Sodium	27,500	250	115	\$0.00	(R)
	High Pressure Sodium	50,000	400	176	\$0.00	(R)
	Metal Halide	9,000	100	39	\$0.00	
	Metal Halide	12,000	175	68	\$0.00	(R)
	Metal Halide	19,500	250	94	\$0.00	(R)
	Metal Halide	32,000	400	149	\$0.00	(R)
	Metal Halide	107,800	1,000	354	\$0.00	(R)
	Non-Listed Luminaire, per kWh			0.000¢	(R)	
54, 754	Per kWh			0.000¢	(R)	

## PORTFOLIO TIME-OF-USE SUPPLY SERVICE

Page 1

**Available**

In all territory served by the Company in the State of Oregon.

**Applicable**

To Residential and Small Nonresidential Consumers receiving Delivery Service under Schedules 4, 5, 23 or 41, in conjunction with Supply Service Schedule 201, who have elected to take this service.

**Monthly Billing**

The Monthly Billing shall be the Energy Charge. The Monthly Billing is in addition to all other charges contained in Consumer's applicable Delivery Service schedule, Base Supply Service Schedule 200 and Supply Service Schedule 201.

(C)

(D)

**Energy Charge**

<u>Delivery Service Schedule No.</u>		<u>Season</u>	
		<u>Winter</u>	<u>Summer</u>
4	On-Peak kWh, per kWh Off-Peak kWh, per kWh	3.316 ¢ (1.125)¢	6.124 ¢ (1.125)¢
5	On-Peak kWh, per kWh Off-Peak kWh, per kWh	3.316 ¢ (1.125)¢	6.124 ¢ (1.125)¢
23	On-Peak kWh, per kWh Off-Peak kWh, per kWh	4.365 ¢ (1.438)¢	9.350 ¢ (1.438)¢
41	On-Peak kWh, per kWh Off-Peak kWh, per kWh	3.737 ¢ (1.231)¢	8.004 ¢ (1.231)¢

**Seasonal Definition**

Winter months are defined as October 1 through May 31. Summer months are defined as June 1 through September 30.

(C)

(C)

(D)

**On-Peak Period**

Winter

Monday through Friday 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 8:00 p.m.

Summer

Monday through Friday 4:00 p.m. to 8:00 p.m.

(continued)

**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	(0.208¢)			(C)
Schedule 5	(0.208¢)			
Schedule 15	8.840¢			
Schedule 23, 723	0.000¢	0.000¢		
Schedule 28, 728	0.495¢	0.495¢		
Schedule 30, 730	0.502¢	0.502¢		
Schedule 41, 741	(2.237¢)	(2.237¢)		
Schedule 47, 747	0.000¢	0.000¢	0.000¢	
Schedule 48, 748	0.000¢	0.000¢	0.000¢	
Schedule 51, 751	9.686¢			
Schedule 53, 753	2.447¢			
Schedule 54, 754	3.135¢			



**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**

	<b>Secondary</b>	<b>Primary</b>	
Basic Charge			
Single Phase, per month	\$17.35	\$17.35	
Three Phase, per month	\$25.90	\$25.90	
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW, Load Size	\$ 1.65	\$ 1.65	(I)(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	\$ 5.51	\$ 5.44	(I)(I)
Distribution Energy Charge, per kWh	4.109¢	4.045¢	(I)(I)
Reactive Power Charge, per kvar	\$ 0.65	\$ 0.60	

**System Usage Charge**

Schedule 200 Related, per kWh	0.064¢	0.063¢	(I)(I)
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**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)

**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**

	<b><u>Delivery Voltage</u></b>		
	<b>Secondary</b>	<b>Primary</b>	
Basic Charge			
Load Size ≤ 50 kW, per month	\$ 19.00	\$ 17.00	(R)
Load Size 51-100 kW, per month	\$ 34.00	\$ 30.00	(R)(R)
Load Size 101 - 300 kW, per month	\$ 82.00	\$ 70.00	(R)(R)
Load Size > 300 kW, per month	\$117.00	\$100.00	(R)(R)
Load Size Charge			
≤ 50 kW, per kW Load Size	\$ 1.20	\$ 1.00	(R)
51-100 kW, per kW Load Size	\$ 0.95	\$ 0.80	(R)
101 – 300 kW, per kW Load Size	\$ 0.55	\$ 0.50	(R)
> 300 kW, per kW Load Size	\$ 0.35	\$ 0.25	(R)
Demand Charge, per kW	\$ 3.95	\$ 3.42	(R)(R)
Distribution Energy Charge, per kWh	0.395¢	0.034¢	(R)(R)
Reactive Power Charge, per kvar	\$ 0.65	\$ 0.60	

**System Usage Charge**

Schedule 200 Related, per kWh	0.069¢	0.077¢	(I)(I)
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**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)



**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**

	<b><u>Delivery Voltage</u></b>		
	<b>Secondary</b>	<b>Primary</b>	
Basic Charge			
Load Size ≤ 200 kW, per month	\$438.00	\$410.00	(R)(R)
Load Size 201 - 300 kW, per month	\$128.00	\$130.00	(R)(R)
Load Size > 300 kW, per month	\$339.00	\$338.00	(R)(R)
Load Size Charge			
≤ 200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	\$ 1.55	\$ 1.40	(R)(R)
> 300 kW, per kW Load Size	\$ 0.75	\$ 0.70	(R)(R)
Demand Charge, per kW	\$ 3.72	\$ 3.59	(R)(R)
Reactive Power Charge, per kvar	\$ 0.65	\$ 0.60	

**System Usage Charge**

Schedule 200 Related, per kWh	0.068¢	0.069¢	(I)(I)
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**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)





**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**

	<b>Secondary</b>	<b>Primary</b>	
Basic Charge (November billing only)	No Charge	No Charge	
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	(I)(I)
Three Phase Load Size 51 - 300 kW	\$ 490.00	\$ 480.00	(I)(I)
Three Phase Load Size > 300 kW	\$1,930.00	\$1,900.00	(I)(I)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	\$ 17.10	\$ 16.90	
Three Phase 51 - 300 kW, per kW Load Size	\$ 11.70	\$ 11.50	
Three Phase > 300 kW, per kW Load Size	\$ 7.20	\$ 7.10	
Single Phase, Minimum Charge	\$ 90.00	\$ 90.00	(I)(I)
Three Phase, Minimum Charge	\$ 140.00	\$ 140.00	(I)(I)
Distribution Energy Charge, per kWh	6.140¢	6.045¢	(I)(I)
Reactive Power Charge, per kVar	\$ 0.65	\$ 0.60	

**System Usage Charge**

Schedule 200 Related, per kWh	0.067¢	0.066¢	(I)(I)
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**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:

<b>If Motor Size Is:</b>	<b>Monthly kW is:</b>
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)



**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.

<u>Distribution Charge</u>	<u>Delivery Voltage</u>			
	<u>Secondary</u>	<u>Primary</u>	<u>Transmission</u>	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	\$540.00	\$530.00	\$710.00	(R)(R)
Facility Capacity > 4,000 kW, per month	\$1,500.00	\$1,470.00	\$1,820.00	(R)(R)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	\$2.95	\$1.25	\$1.25	(I)(R)
> 4,000 kW, per kW Facility Capacity	\$0.80	\$0.85	\$1.05	
On-Peak Demand Charge, per kW	\$3.42	\$3.65	\$2.04	(R)(R)(R)
Reactive Power Charges				
Per kVar	\$0.65	\$0.60	\$0.55	
Per kVarh	\$0.0008	\$0.0008	\$0.0008	
 <u>Reserves Charges</u>				
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)	
 <u>System Usage Charge</u>				
Schedule 200 Related, per kWh	0.068¢	0.065¢	0.062¢	(I)(I)(I)

(continued)



**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.

	<u>Delivery Voltage</u>			
	<u>Distribution Charge</u>	Secondary	Primary	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	\$540.00	\$530.00	\$710.00	(R)
Facility Capacity > 4000 kW, per month	\$1,500.00	\$1,470.00	\$1,820.00	(R)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	\$2.95	\$1.25	\$1.25	(I)(R)
> 4000 kW, per kW Facility Capacity	\$0.80	\$0.85	\$1.05	
On-Peak Demand Charge, per kW	\$3.42	\$3.65	\$2.04	(R)(R)(R)
Reactive Power Charge, per kvar	\$0.65	\$0.60	\$0.55	
<u>System Usage Charge</u>				
Schedule 200 Related, per kWh		0.068¢	0.065¢	0.062¢ (I)(I)(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)



**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	\$ 5.78	\$ 6.12	\$ 6.22	\$ 6.31	\$ 6.70	\$ 8.16	(R)
Functional Lighting - Customer Funded Conversion	\$ 3.11	\$ 3.28	\$ 3.37	\$ 3.42	\$ 3.65	\$ 4.46	(R)
Decorative Series	N/A	\$ 10.57	\$ 10.64	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)



**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.

<b>High Pressure Sodium Vapor</b>						
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	\$ 1.16	\$ 1.65	\$ 2.40	\$ 3.19	\$ 4.32	\$ 6.61

(R)

<b>Metal Halide</b>					
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	\$ 1.46	\$ 2.55	\$ 3.53	\$ 5.60	\$ 13.30

(R)

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.

<b>Non-Listed Luminaire</b>	<b>¢/kWh</b>
Energy Only Service	3.756

(R)

**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)

**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	4.090¢	(R)

**System Usage Charge**

Schedule 200 Related, per kWh	0.018¢	(R)
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**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.



**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:

	<u>Secondary</u>	<u>Delivery Voltage</u>		
		<u>Primary</u>	<u>Transmission</u>	
<b>Daily ERS Demand Charge</b>				
per kW of Daily ERS On-Peak Demand	\$0.133	\$0.142	\$0.079	(R)

**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)



**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.

<u>Distribution Charge</u>	<u>Delivery Voltage</u>			
	<u>Secondary</u>	<u>Primary</u>	<u>Transmission</u>	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	\$540.00	\$530.00	\$710.00	(R)(R)
Facility Capacity > 4000 kW, per month	\$1,500.00	\$1,470.00	\$1,820.00	(R)(R)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	\$2.95	\$1.25	\$1.25	(I)(R)
> 4000 kW, per kW Facility Capacity	\$0.80	\$0.85	\$1.05	
On-Peak Demand Charge, per kW	\$3.42	\$3.65	\$2.04	(R)(R)(R)
Reactive Power Charge, per kvar	\$0.65	\$0.60	\$0.55	

**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)



**GENERAL RULES AND REGULATIONS**  
**BILLING**

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**I. Billing – General**

Meters ordinarily will be read and bills rendered at intervals of approximately one month. Company reserves the right to bill any Consumer for a period shorter or longer than one month but in no event shall meters be read and bills rendered for any single period longer than six months. Each special meter reading made at the request of Consumer may be subject to an additional charge which reflects costs incurred by Company. Consumer shall be informed of and agree to charges prior to meter reading. Except for initial, final, Force Majeure bills and Residential kilowatt-hour seasons as described in Section A below, no bill will be prorated when service is used for less than a full month. (C)

**A. Residential Seasonal Kilowatt-Hour Proration (C)**

Seasonal kilowatt-hour usage will be prorated to the nearest whole kilowatt-hour based (C)  
upon the number of whole days in the billing period falling within each season. (C)

(D)

(continued)

Docket No. UE 399  
Exhibit PAC/1102  
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Robert M. Meredith  
Unbundled Results of Operations - Summary and Detail**

**March 2022**

PACIFICORP  
 STATE OF OREGON  
 Combined GRC and TAM  
 Functionalized Revenue Requirement  
 12 Months Ended December 31, 2023 Forecast

Function	Revenue Requirement	
Production	\$	749,838,433
Transmission	\$	181,004,744
Distribution	\$	399,594,389
Distribution-Lighting	\$	3,324,376
Distribution Total	\$	402,918,765
Ancillary	\$	23,847,685
Customer Billing	\$	15,188,944
Customer Metering	\$	21,184,339
Customer Other	\$	9,291,508
Retail Service	a \$	-
Public Purposes	b \$	-
<b>Total State of Oregon</b>	<b>\$</b>	<b>1,403,274,417</b>

a - Retail Services are conducted as unregulated activities.

b - DSM is collected by a separate tariff.

Public Purposes are collected by a separate tariff.

PACIFICORP  
STATE OF OREGON  
Combined GRC and TAM  
Functionalized Revenue Requirement  
12 Months Ended December 31, 2023 Forecast

	ROR	ROE	Total \$	Production	Transmission	Distribution	Distribution- Lighting	Ancillary	Customer			Distribution Components		
									Billing	Metering	Other	Poles & Wires	Poles & Wires-Lighting	Franchise Fees
1 Functionalized Situs Revenues @ Earned	4.53%	4.67%	1,248,901,150	698,715,686	133,281,168	348,421,271	2,779,043	23,847,685	14,719,951	18,059,162	9,077,184	319,433,928	2,547,837	29,218,549
2 System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-
3 Total Oregon General Business Revenue			1,248,901,150	698,715,686	133,281,168	348,421,271	2,779,043	23,847,685	14,719,951	18,059,162	9,077,184	319,433,928	2,547,837	29,218,549
4														
5 Target Increase in Return	7.21%	9.80%	112,602,309	38,195,747	35,656,098	35,526,403	378,591	-	350,403	2,334,938	160,129	35,526,403	378,591	-
6														
7 Add														
8 Uncollectible Expense			771,495	255,491	238,503	255,743	2,725	-	2,344	15,618	1,071	237,636	2,532	18,300
9 Franchise Tax			3,627,772			3,589,520	38,252							3,627,772
10 Other Revenue Based Taxes			660,604	218,768	204,222	218,983	2,334	-	2,007	13,373	917	203,479	2,168	15,670
11 Inc Taxes - State			6,778,828	2,299,441	2,146,551	2,138,743	22,792	-	21,095	140,567	9,640	2,138,743	22,792	-
12 Inc Taxes - Federal			29,932,259	10,153,300	9,478,203	9,443,727	100,638	-	93,145	620,680	42,566	9,443,727	100,638	-
13 Total Increase Needed			154,373,268	51,122,747	47,723,576	51,173,118	545,332	-	468,993	3,125,177	214,324	47,549,987	506,722	3,661,741
14														
15 Total Oregon General Business Revenue @	7.21%	9.80%	1,403,274,418	749,838,433	181,004,744	399,594,389	3,324,376	23,847,685	15,188,944	21,184,339	9,291,508	366,983,916	3,054,559	32,880,290
16 Less: System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-
17 Total Unbundled Revenue Requirement			1,403,274,418	749,838,433	181,004,744	399,594,389	3,324,376	23,847,685	15,188,944	21,184,339	9,291,508	366,983,916	3,054,559	32,880,290
18														
19 Rate Base			4,199,121,534	1,424,380,946	1,329,673,331	1,324,836,797	14,118,283	-	13,067,082	87,073,613	5,971,482	1,324,836,797	14,118,283	-
				33.92%	31.67%	31.55%	0.34%	0.00%	0.31%	2.07%	0.14%	31.55%	0.34%	0.00%

Notes:  
Row 9: Franchise Tax @ 2.35%  
Row 11: Inc Taxes - State 4.54%  
Row 12: Inc Taxes - Federal 21.00%

Docket No. UE 399  
Exhibit PAC/1103  
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Robert M. Meredith  
Functionalized Oregon Results of Operations Report**

**March 2022**

PACIFICORP  
STATE OF OREGON  
Combined GRC and TAM  
Unbundled Results of Operations  
12 Months Ended December 31, 2023 Forecast

	Total \$	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C Billing	C Metering	C Other
<b>Operating Revenues</b>									
General Business Revenues	1,248,901,150	698,715,686	133,281,168	348,421,271	2,779,043	23,847,685	14,719,951	18,059,162	9,077,184
Special Sales	92,708,477	92,708,477	-	-	-	-	-	-	-
Other Operating Revenues	81,179,990	38,936,768	60,434,442	4,104,857	3,204	(23,847,685)	661,823	390,032	496,550
<b>Total Operating Revenues</b>	<b>1,422,789,617</b>	<b>830,360,932</b>	<b>193,715,609</b>	<b>352,526,128</b>	<b>2,782,247</b>	<b>-</b>	<b>15,381,774</b>	<b>18,449,194</b>	<b>9,573,734</b>
<b>Operating Expenses</b>									
Steam Production	238,036,042	238,036,042	-	-	-	-	-	-	-
Nuclear Production	-	-	-	-	-	-	-	-	-
Hydro Production	12,077,585	12,077,585	-	-	-	-	-	-	-
Other Power Supply	343,636,569	343,636,569	-	-	-	-	-	-	-
ECD	-	-	-	-	-	-	-	-	-
Transmission	60,587,175	201,730	60,385,445	-	-	-	-	-	-
Distribution	116,940,088	-	-	114,306,114	874,599	-	-	1,759,374	-
Customer Accounts	23,492,890	3,670,779	856,359	1,558,413	12,299	-	9,681,818	3,847,829	3,865,393
Customer Service	6,029,376	-	-	3,710,056	-	-	-	-	2,319,320
Sales	-	-	-	-	-	-	-	-	-
Administrative & General	60,742,837	14,987,633	6,062,882	34,150,269	180,571	-	1,914,858	2,447,475	999,149
<b>Total O &amp; M Expenses</b>	<b>861,542,561</b>	<b>612,610,337</b>	<b>67,304,687</b>	<b>153,724,852</b>	<b>1,067,470</b>	<b>-</b>	<b>11,596,676</b>	<b>8,054,679</b>	<b>7,183,862</b>
Depreciation	287,994,295	184,502,530	40,225,922	58,597,189	829,712	-	550,435	2,988,279	300,228
Amortization Expense	43,237,301	5,795,483	1,660,641	29,375,575	45,969	-	2,363,170	2,356,565	1,639,897
Taxes Other Than Income	84,171,808	24,456,422	12,622,760	45,488,639	196,642	-	321,645	876,129	209,570
Income Taxes - Federal	(61,296,146)	(73,814,488)	2,905,895	9,639,311	263,277	-	(494,435)	564,566	(360,273)
Income Taxes - State	4,230,426	2,468,939	575,981	1,048,177	8,273	-	45,735	54,856	28,466
Income Taxes - Def Net	12,660,019	10,316,399	8,177,502	(5,882,254)	(268,741)	-	406,528	(390,854)	301,439
Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-
Misc Revenue & Expense	3,165	(507,960)	(208)	511,333	-	-	-	-	-
<b>Total Operating Expenses</b>	<b>1,232,543,429</b>	<b>765,827,662</b>	<b>133,473,180</b>	<b>292,502,823</b>	<b>2,142,601</b>	<b>-</b>	<b>14,789,754</b>	<b>14,504,220</b>	<b>9,303,189</b>
<b>Operating Revenue for Return</b>	<b>190,246,188</b>	<b>64,533,270</b>	<b>60,242,429</b>	<b>60,023,304</b>	<b>639,646</b>	<b>-</b>	<b>592,020</b>	<b>3,944,973</b>	<b>270,545</b>
<b>Rate Base</b>									
Electric Plant in Service	8,852,783,093	3,772,543,856	2,125,517,618	2,694,175,792	33,216,336	-	49,538,693	145,315,143	32,475,655
Plant Held for Future Use	-	1,762,429	(562,535)	(1,126,001)	-	-	(36,884)	(37,008)	-
Misc Deferred Debits	67,300,330	57,747,019	3,109,293	4,471,781	71,600	-	729,361	769,574	401,700
Elec Plant Acq Adj	701,604	701,604	-	-	-	-	-	-	-
Nuclear Fuel	-	-	-	-	-	-	-	-	-
Prepayments	11,129,917	4,754,958	1,152,784	3,627,057	58,026	-	589,668	622,635	324,789
Fuel Stock	43,192,126	43,192,126	-	-	-	-	-	-	-
Material & Supplies	81,719,811	66,753,694	1,208,964	13,319,385	-	-	-	437,768	-
Working Capital	13,347,565	5,022,220	1,471,478	5,174,255	65,382	-	626,090	636,191	351,949
Weatherization Loans	-	-	-	-	-	-	-	-	-
Miscellaneous Rate Base	-	-	-	-	-	-	-	-	-
<b>Total Electric Plant</b>	<b>9,070,174,446</b>	<b>3,952,477,905</b>	<b>2,131,897,602</b>	<b>2,719,642,270</b>	<b>33,411,344</b>	<b>-</b>	<b>51,446,928</b>	<b>147,744,303</b>	<b>33,554,093</b>
<b>Rate Base Deductions</b>									
Accum Prov For Depr	(3,571,364,011)	(1,740,982,885)	(579,491,671)	(1,198,794,615)	(16,682,711)	-	(3,399,166)	(30,162,765)	(1,850,199)
Accum Prov For Amort	(218,109,109)	(72,164,303)	(20,477,039)	(49,139,039)	(766,899)	-	(32,286,235)	(21,010,836)	(22,264,757)
Accum Def Income Taxes	(643,480,187)	(314,240,940)	(179,474,281)	(136,156,929)	(1,680,147)	-	(1,298,298)	(7,930,873)	(2,698,719)
Unamortized ITC	(45,778)	(18,624)	(3,492)	(16,420)	(263)	-	(2,678)	(2,826)	(1,475)
Customer Adv for Const	(23,030,533)	-	(20,960,626)	(1,961,291)	(23,889)	-	-	(84,727)	-
Customer Service Deposits	-	-	-	-	-	-	-	-	-
Misc. Rate Base Deductions	(415,023,294)	(400,690,208)	(1,817,162)	(8,737,180)	(139,153)	-	(1,393,468)	(1,478,662)	(767,461)
<b>Total Rate Base Deductions</b>	<b>(4,871,052,912)</b>	<b>(2,528,096,959)</b>	<b>(802,224,271)</b>	<b>(1,394,805,473)</b>	<b>(19,293,062)</b>	<b>-</b>	<b>(38,379,846)</b>	<b>(60,670,690)</b>	<b>(27,582,611)</b>
<b>Total Rate Base</b>	<b>4,199,121,534</b>	<b>1,424,380,946</b>	<b>1,329,673,331</b>	<b>1,324,836,797</b>	<b>14,118,283</b>	<b>-</b>	<b>13,067,082</b>	<b>87,073,613</b>	<b>5,971,482</b>
<b>Return on Rate Base</b>	<b>4.5306%</b>	<b>4.5306%</b>	<b>4.5306%</b>	<b>4.5306%</b>	<b>4.5306%</b>	<b>4.5306%</b>	<b>4.5306%</b>	<b>4.5306%</b>	<b>4.5306%</b>
<b>Return on Equity</b>	<b>4.6678%</b>	<b>4.6678%</b>	<b>4.6678%</b>	<b>4.6678%</b>	<b>4.6678%</b>	<b>4.6678%</b>	<b>4.6678%</b>	<b>4.6678%</b>	<b>4.6678%</b>

2020 PROTOCOL  
RESULTS OF OPERATIONS SUMMARY  
12 Months Ended December 31, 2023 Forecast

		Total \$	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C Billing	C Metering	C Service	DSM
<b>Operating Revenues</b>											
General Business Revenues		1,248,901,150	698,715,686	133,281,168	348,421,271	2,779,043	23,847,685	14,719,951	18,059,162	9,077,184	-
General Business Revenues		-	-	-	-	-	-	-	-	-	-
Interdepartmental		-	-	-	-	-	-	-	-	-	-
Special Sales		92,708,477	92,708,477	-	-	-	-	-	-	-	-
Other Operating Revenues		81,179,990	38,936,768	60,434,442	4,104,857	3,204	(23,847,685)	661,823	390,032	496,550	-
<b>Total Operating Revenues</b>		<b>1,422,789,617</b>	<b>830,360,932</b>	<b>193,715,609</b>	<b>352,526,128</b>	<b>2,782,247</b>	<b>-</b>	<b>15,381,774</b>	<b>18,449,194</b>	<b>9,573,734</b>	<b>-</b>
<b>Operating Expenses</b>											
Steam Production		238,036,042	238,036,042	-	-	-	-	-	-	-	-
Nuclear Production		-	-	-	-	-	-	-	-	-	-
Hydro Production		12,077,585	12,077,585	-	-	-	-	-	-	-	-
Other Power Supply		343,636,569	343,636,569	-	-	-	-	-	-	-	-
ECD		-	-	-	-	-	-	-	-	-	-
Transmission		60,587,175	201,730	60,385,445	-	-	-	-	-	-	-
Distribution		116,940,088	-	-	114,306,114	874,599	-	-	1,759,374	-	-
Customer Accounts		23,492,890	3,670,779	856,359	1,558,413	12,299	-	9,681,818	3,847,829	3,865,393	-
Customer Service		6,029,376	-	-	3,710,056	-	-	-	-	2,319,320	-
Sales		-	-	-	-	-	-	-	-	-	-
Administrative & General		60,742,837	14,987,633	6,062,882	34,150,269	180,571	-	1,914,858	2,447,475	999,149	-
<b>Total O &amp; M Expenses</b>		<b>861,542,561</b>	<b>612,610,337</b>	<b>67,304,687</b>	<b>153,724,852</b>	<b>1,067,470</b>	<b>-</b>	<b>11,596,676</b>	<b>8,054,679</b>	<b>7,183,862</b>	<b>-</b>
Depreciation		287,994,295	184,502,530	40,225,922	58,597,189	829,712	-	550,435	2,988,279	300,228	-
Amortization Expense		43,237,301	5,795,483	1,660,641	29,375,575	45,969	-	2,363,170	2,356,565	1,639,897	-
Taxes Other Than Income		84,171,808	24,456,422	12,622,760	45,488,639	196,642	-	321,645	876,129	209,570	-
Income Taxes - Federal		(61,296,146)	(73,814,488)	2,905,895	9,639,311	263,277	-	(494,435)	564,566	(360,273)	-
Income Taxes - State		4,230,426	2,468,939	575,981	1,048,177	8,273	-	45,735	54,856	28,466	-
Income Taxes - Def Net		12,660,019	10,316,999	8,177,502	(5,882,254)	(268,741)	-	406,528	(390,854)	301,439	-
Investment Tax Credit Adj.		-	-	-	-	-	-	-	-	-	-
Misc Revenue & Expense		3,165	(507,960)	(208)	511,333	-	-	-	-	-	-
<b>Total Operating Expenses</b>		<b>1,232,543,429</b>	<b>765,827,662</b>	<b>133,473,180</b>	<b>292,502,823</b>	<b>2,142,601</b>	<b>-</b>	<b>14,789,754</b>	<b>14,504,220</b>	<b>9,303,189</b>	<b>-</b>
<b>Operating Revenue for Return</b>		<b>190,246,188</b>	<b>64,533,270</b>	<b>60,242,429</b>	<b>60,023,304</b>	<b>639,646</b>	<b>-</b>	<b>592,020</b>	<b>3,944,973</b>	<b>270,545</b>	<b>-</b>
<b>Rate Base</b>											
Electric Plant in Service		8,852,783,093	3,772,543,856	2,125,517,618	2,694,175,792	33,216,336	-	49,538,693	145,315,143	32,475,655	-
Plant Held for Future Use		-	1,762,429	(562,535)	(1,126,001)	-	-	(36,884)	(37,008)	-	-
Misc Deferred Debits		67,300,330	57,747,019	3,109,293	4,471,781	71,600	-	729,361	769,574	401,700	-
Elec Plant Acq Adj		701,604	701,604	-	-	-	-	-	-	-	-
Nuclear Fuel		-	-	-	-	-	-	-	-	-	-
Prepayments		11,129,917	4,754,958	1,152,784	3,627,057	58,026	-	589,668	622,635	324,789	-
Fuel Stock		43,192,126	43,192,126	-	-	-	-	-	-	-	-
Material & Supplies		81,719,811	66,753,694	1,208,964	13,319,385	-	-	-	437,768	-	-
Working Capital		13,347,565	5,022,220	1,471,478	5,174,255	65,382	-	626,090	636,191	351,949	-
Weatherization Loans		-	-	-	-	-	-	-	-	-	-
Miscellaneous Rate Base		-	-	-	-	-	-	-	-	-	-
<b>Total Electric Plant</b>		<b>9,070,174,446</b>	<b>3,952,477,905</b>	<b>2,131,897,602</b>	<b>2,719,642,270</b>	<b>33,411,344</b>	<b>-</b>	<b>51,446,928</b>	<b>147,744,303</b>	<b>33,554,093</b>	<b>-</b>
<b>Rate Base Deductions</b>											
Accum Prov For Depr		(3,571,364,011)	(1,740,982,885)	(579,491,671)	(1,198,794,615)	(16,682,711)	-	(3,399,166)	(30,162,765)	(1,850,199)	-
Accum Prov For Amort		(218,109,109)	(72,164,303)	(20,477,039)	(49,139,039)	(766,899)	-	(32,286,235)	(21,010,836)	(22,264,757)	-
Accum Def Income Taxes		(643,480,187)	(314,240,940)	(179,474,281)	(136,156,929)	(1,680,147)	-	(1,298,298)	(7,930,873)	(2,698,719)	-
Unamortized ITC		(45,778)	(18,624)	(3,492)	(16,420)	(263)	-	(2,678)	(2,826)	(1,475)	-
Customer Adv for Const		(23,030,533)	-	(20,960,626)	(1,961,291)	(23,889)	-	-	(84,727)	-	-
Customer Service Deposits		-	-	-	-	-	-	-	-	-	-
Misc. Rate Base Deductions		(415,023,294)	(400,690,208)	(1,817,162)	(8,737,180)	(139,153)	-	(1,393,468)	(1,478,662)	(767,461)	-
<b>Total Rate Base Deductions</b>		<b>(4,871,052,912)</b>	<b>(2,528,096,959)</b>	<b>(802,224,271)</b>	<b>(1,394,805,473)</b>	<b>(19,293,062)</b>	<b>-</b>	<b>(38,379,846)</b>	<b>(60,670,690)</b>	<b>(27,582,611)</b>	<b>-</b>
<b>Total Rate Base</b>		<b>4,199,121,534</b>	<b>1,424,380,946</b>	<b>1,329,673,331</b>	<b>1,324,836,797</b>	<b>14,118,283</b>	<b>-</b>	<b>13,067,082</b>	<b>87,073,613</b>	<b>5,971,482</b>	<b>-</b>
<b>Return on Rate Base</b>		<b>4.531%</b>	<b>4.531%</b>	<b>4.531%</b>	<b>4.531%</b>	<b>4.531%</b>	<b>4.531%</b>	<b>4.531%</b>	<b>4.531%</b>	<b>4.531%</b>	<b>0.000%</b>
<b>Return on Equity</b>		<b>4.668%</b>	<b>4.668%</b>	<b>4.668%</b>	<b>4.668%</b>	<b>4.668%</b>	<b>4.668%</b>	<b>4.668%</b>	<b>4.668%</b>	<b>4.668%</b>	<b>0.000%</b>

RESULTS OF OPERATIONS SUMMARY

2020 PROTOCOL		FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total \$	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C Billing	C Metering	C Service	DSM
Sales to Ultimate Customers															
440	Residential Sales				S	613,521,236	698,715,686	133,281,168	348,421,271	2,779,043	23,847,685	14,719,951	18,059,162	9,077,184	-
	Less Klamath Surcharge Revenue			P	S	-	-	-	-	-	-	-	-	-	-
						613,521,236	698,715,686	133,281,168	348,421,271	2,779,043	23,847,685	14,719,951	18,059,162	9,077,184	-
442	Commercial & Industrial Sales				S	631,085,295	-	-	-	-	-	-	-	-	-
				P	SE	-	-	-	-	-	-	-	-	-	-
				PT	SG	-	-	-	-	-	-	-	-	-	-
						631,085,295	-	-	-	-	-	-	-	-	-
444	Public Street & Highway Lighting				S	4,294,618	-	-	-	-	-	-	-	-	-
					SO	-	-	-	-	-	-	-	-	-	-
						4,294,618	-	-	-	-	-	-	-	-	-
445	Other Sales to Public Authority				S	-	-	-	-	-	-	-	-	-	-
						-	-	-	-	-	-	-	-	-	-
448	Interdepartmental				S	-	-	-	-	-	-	-	-	-	-
				D_SPLIT	GP	-	-	-	-	-	-	-	-	-	-
					SO	-	-	-	-	-	-	-	-	-	-
						-	-	-	-	-	-	-	-	-	-
<b>Total Sales to Ultimate Customers</b>						<b>1,248,901,150</b>	<b>698,715,686</b>	<b>133,281,168</b>	<b>348,421,271</b>	<b>2,779,043</b>	<b>23,847,685</b>	<b>14,719,951</b>	<b>18,059,162</b>	<b>9,077,184</b>	<b>-</b>

447	Sales for Resale-Non NPC	P	S	-	-	-	-	-	-	-	-	-	-
447NPC	Sales for Resale-NPC	P	SG	92,708,477	92,708,477	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				92,708,477	92,708,477	-	-	-	-	-	-	-	-
	Total Sales for Resale			92,708,477	92,708,477	-	-	-	-	-	-	-	-
449	Provision for Rate Refund	P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(844,658)	(844,658)	-	-	-	-	-	-	-	-
				(844,658)	(844,658)	-	-	-	-	-	-	-	-
	<b>Total Sales from Electricity</b>			<b>1,340,764,969</b>	<b>790,579,506</b>	<b>133,281,168</b>	<b>348,421,271</b>	<b>2,779,043</b>	<b>23,847,685</b>	<b>14,719,951</b>	<b>18,059,162</b>	<b>9,077,184</b>	-
450	Forfeited Discounts & Interest	C_BILLING	S	(19,497)	-	-	-	-	-	(19,497)	-	-	-
		C_BILLING	SO	-	-	-	-	-	-	-	-	-	-
				(19,497)	-	-	-	-	-	(19,497)	-	-	-
451	Misc Electric Revenue	CSS_SYS	S	1,526,034	-	-	-	-	-	676,542	356,075	493,418	-
		C_METER	S	19,942	-	-	-	-	-	-	19,942	-	-
		GP	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	14,354	-	-	14,354	-	-	-	-	-	-
				1,560,331	-	-	14,354	-	-	676,542	376,017	493,418	-
453	Water Sales	P	SG	1,916	1,916	-	-	-	-	-	-	-	-
				1,916	1,916	-	-	-	-	-	-	-	-
454	Rent of Electric Property	D	S	4,606,685	-	-	4,606,685	-	-	-	-	-	-
		T	SG	1,269,017	-	1,269,017	-	-	-	-	-	-	-
		GP	SO	853,809	363,844	204,996	259,841	3,204	-	4,778	14,015	3,132	-
				6,729,512	363,844	1,474,013	4,866,526	3,204	-	4,778	14,015	3,132	-
	Oregon Ancillary Services				23,847,685				(23,847,685)				
456	Other Electric Revenue	OTHSGR	S	28,036,644	6,429,957	21,605,877	810	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-	-
		OTHSE	SE	6,649,054	-	6,649,054	-	-	-	-	-	-	-
		OTHSE	SO	(777,986)	-	-	(777,986)	-	-	-	-	-	-
		OTHSGR	SG	39,844,674	9,138,024	30,705,498	1,152	-	-	-	-	-	-
				73,752,386	15,567,981	58,960,429	(776,024)	-	-	-	-	-	-
	<b>Total Other Electric Revenues</b>			<b>82,024,648</b>	<b>39,781,426</b>	<b>60,434,442</b>	<b>4,104,857</b>	<b>3,204</b>	<b>(23,847,685)</b>	<b>661,823</b>	<b>390,032</b>	<b>496,550</b>	-
	<b>Total Electric Operating Revenues</b>			<b>1,422,789,617</b>	<b>830,360,932</b>	<b>193,715,609</b>	<b>352,526,128</b>	<b>2,782,247</b>	-	<b>15,381,774</b>	<b>18,449,194</b>	<b>9,573,734</b>	-
	Miscellaneous Revenues												
41160	Gain on Sale of Utility Plant - CR	D	S	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		G	SO	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
41170	Loss on Sale of Utility Plant	D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
4118	Gain from Emission Allowances	P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	(12)	(12)	-	-	-	-	-	-	-	-
				(12)	(12)	-	-	-	-	-	-	-	-
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	511,579	-	-	511,579	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		PTD	SO	(801)	(348)	(208)	(246)	-	-	-	-	-	-
		P	SG	(507,601)	(507,601)	-	-	-	-	-	-	-	-
				3,177	(507,948)	(208)	511,333	-	-	-	-	-	-
	<b>Total Miscellaneous Revenues</b>			<b>3,165</b>	<b>(507,960)</b>	<b>(208)</b>	<b>511,333</b>	-	-	-	-	-	-
	Miscellaneous Expenses												
4311	Interest on Customer Deposits	C_BILLING	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	<b>Total Miscellaneous Expenses</b>			<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
	<b>Net Misc Revenue and Expense</b>			<b>3,165</b>	<b>(507,960)</b>	<b>(208)</b>	<b>511,333</b>	-	-	-	-	-	-
500	Operation Supervision & Engineering	P	SG	3,814,692	3,814,692	-	-	-	-	-	-	-	-
		P	SG	305,930	305,930	-	-	-	-	-	-	-	-
		P	SG	(15)	(15)	-	-	-	-	-	-	-	-
				4,120,607	4,120,607	-	-	-	-	-	-	-	-
501	Fuel Related-Non NPC	P	S	5,325,016	5,325,016	-	-	-	-	-	-	-	-
		P	SE	8,179,260	8,179,260	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-



	P	SE	-	-	-	-	-	-	-	-	-	-
	P	SE	71,745	71,745	-	-	-	-	-	-	-	-
	P	SE	-	-	-	-	-	-	-	-	-	-
			13,576,021	13,576,021	-	-	-	-	-	-	-	-
501NPC	Fuel Related-NPC											
	P	S	-	-	-	-	-	-	-	-	-	-
	P	SE	145,908,002	145,908,002	-	-	-	-	-	-	-	-
	P	SE	-	-	-	-	-	-	-	-	-	-
	P	SE	-	-	-	-	-	-	-	-	-	-
	P	SE	7,781,339	7,781,339	-	-	-	-	-	-	-	-
	P	SE	-	-	-	-	-	-	-	-	-	-
			153,689,341	153,689,341	-	-	-	-	-	-	-	-
	Total Fuel Related		167,265,362	167,265,362	-	-	-	-	-	-	-	-
502	Steam Expenses											
	P	SG	21,162,834	21,162,834	-	-	-	-	-	-	-	-
	P	SG	1,302,554	1,302,554	-	-	-	-	-	-	-	-
	P	SG	0	0	-	-	-	-	-	-	-	-
			22,465,388	22,465,388	-	-	-	-	-	-	-	-
503	Steam From Other Sources-Non-NPC											
	P	SE	(610)	(610)	-	-	-	-	-	-	-	-
			(610)	(610)	-	-	-	-	-	-	-	-
503NPC	Steam From Other Sources-NPC											
	P	SE	1,124,082	1,124,082	-	-	-	-	-	-	-	-
			1,124,082	1,124,082	-	-	-	-	-	-	-	-
505	Electric Expenses											
	P	SG	293,368	293,368	-	-	-	-	-	-	-	-
	P	SG	37,001	37,001	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
			330,369	330,369	-	-	-	-	-	-	-	-
506	Misc. Steam Expense											
	P	SG	15,969,987	15,969,987	-	-	-	-	-	-	-	-
	P	SG	(14,112,418)	(14,112,418)	-	-	-	-	-	-	-	-
	P	SG	408,646	408,646	-	-	-	-	-	-	-	-
			2,266,215	2,266,215	-	-	-	-	-	-	-	-
507	Rents											
	P	SG	131,637	131,637	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
	P	SG	67	67	-	-	-	-	-	-	-	-
			131,704	131,704	-	-	-	-	-	-	-	-
510	Maint Supervision & Engineering											
	P	SG	1,653,017	1,653,017	-	-	-	-	-	-	-	-
	P	SG	296,875	296,875	-	-	-	-	-	-	-	-
	P	SG	158,733	158,733	-	-	-	-	-	-	-	-
			2,108,625	2,108,625	-	-	-	-	-	-	-	-
511	Maintenance of Structures											
	P	SG	6,108,182	6,108,182	-	-	-	-	-	-	-	-
	P	SG	711,090	711,090	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
			6,819,272	6,819,272	-	-	-	-	-	-	-	-
512	Maintenance of Boiler Plant											
	P	SG	18,853,516	18,853,516	-	-	-	-	-	-	-	-
	P	SG	486,746	486,746	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
			19,340,261	19,340,261	-	-	-	-	-	-	-	-
513	Maintenance of Electric Plant											
	P	SG	8,630,491	8,630,491	-	-	-	-	-	-	-	-
	P	SG	83,912	83,912	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
			8,714,403	8,714,403	-	-	-	-	-	-	-	-
514	Maintenance of Misc. Steam Plant											
	P	SG	2,942,439	2,942,439	-	-	-	-	-	-	-	-
	P	SG	407,929	407,929	-	-	-	-	-	-	-	-
	P	SG	(6)	(6)	-	-	-	-	-	-	-	-
			3,350,362	3,350,362	-	-	-	-	-	-	-	-
<b>Total Steam Power Generation</b>			<b>238,036,042</b>	<b>238,036,042</b>	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-
<b>Total Nuclear Power Generation</b>				-	-	-	-	-	-	-	-	-	-
535	Operation Super & Engineering	P	SG	(15)	(15)	-	-	-	-	-	-	-	-
		P	SG	(634)	(634)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	2,645,604	2,645,604	-	-	-	-	-	-	-	-
		P	SG	432,509	432,509	-	-	-	-	-	-	-	-
				3,077,463	3,077,463	-	-	-	-	-	-	-	-
536	Water For Power	P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	83,342	83,342	-	-	-	-	-	-	-	-
				83,342	83,342	-	-	-	-	-	-	-	-
537	Hydraulic Expenses	P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	1,181,426	1,181,426	-	-	-	-	-	-	-	-
		P	SG	90,386	90,386	-	-	-	-	-	-	-	-
				1,271,812	1,271,812	-	-	-	-	-	-	-	-
538	Electric Expenses	P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
539	Misc. Hydro Expenses	P	SG	15	15	-	-	-	-	-	-	-	-
		P	SG	3,295,206	3,295,206	-	-	-	-	-	-	-	-
		P	SG	1,816,085	1,816,085	-	-	-	-	-	-	-	-
				5,111,306	5,111,306	-	-	-	-	-	-	-	-
540	Rents (Hydro Generation)	P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	408,188	408,188	-	-	-	-	-	-	-	-
		P	SG	18,221	18,221	-	-	-	-	-	-	-	-
				426,410	426,410	-	-	-	-	-	-	-	-
541	Maint Supervision & Engineering	P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	107	107	-	-	-	-	-	-	-	-
				107	107	-	-	-	-	-	-	-	-
542	Maintenance of Structures	P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	206,101	206,101	-	-	-	-	-	-	-	-
		P	SG	20,182	20,182	-	-	-	-	-	-	-	-
				226,282	226,282	-	-	-	-	-	-	-	-
543	Maintenance of Dams & Waterways	P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	192,549	192,549	-	-	-	-	-	-	-	-
		P	SG	98,609	98,609	-	-	-	-	-	-	-	-
				291,159	291,159	-	-	-	-	-	-	-	-
544	Maintenance of Electric Plant	P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	450,909	450,909	-	-	-	-	-	-	-	-
		P	SG	69,322	69,322	-	-	-	-	-	-	-	-
				520,231	520,231	-	-	-	-	-	-	-	-
545	Maintenance of Misc. Hydro Plant	P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	836,324	836,324	-	-	-	-	-	-	-	-
		P	SG	233,149	233,149	-	-	-	-	-	-	-	-
				1,069,473	1,069,473	-	-	-	-	-	-	-	-
<b>Total Hydraulic Power Generation</b>				<b>12,077,585</b>	<b>12,077,585</b>	-	-	-	-	-	-	-	-
546	Operation Super & Engineering	P	SG	90,755	90,755	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(3)	(3)	-	-	-	-	-	-	-	-
				90,752	90,752	-	-	-	-	-	-	-	-
547	Fuel-Non-NPC	P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
547NPC	Fuel-NPC	P	SE	77,422,181	77,422,181	-	-	-	-	-	-	-	-

	P	SE	496,371	496,371	-	-	-	-	-	-	-	-	-	-
			77,918,552	77,918,552	-	-	-	-	-	-	-	-	-	-
548	Generation Expense													
	P	SG	4,955,807	4,955,807	-	-	-	-	-	-	-	-	-	-
	P	SG	107,687	107,687	-	-	-	-	-	-	-	-	-	-
	P	SG	(79)	(79)	-	-	-	-	-	-	-	-	-	-
			5,063,415	5,063,415	-	-	-	-	-	-	-	-	-	-
549	Miscellaneous Other													
	P	S	34,592	34,592	-	-	-	-	-	-	-	-	-	-
	P	SG	1,109,540	1,109,540	-	-	-	-	-	-	-	-	-	-
	P	SG	1,270,008	1,270,008	-	-	-	-	-	-	-	-	-	-
	P	SG	(8,715)	(8,715)	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-	-	-
			2,405,425	2,405,425	-	-	-	-	-	-	-	-	-	-
550	Maint Supervision & Engineering													
	P	S	410,642	410,642	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-	-	-
	P	SG	11,561	11,561	-	-	-	-	-	-	-	-	-	-
	P	SG	2,104,117	2,104,117	-	-	-	-	-	-	-	-	-	-
			2,526,321	2,526,321	-	-	-	-	-	-	-	-	-	-
551	Maint Supervision & Engineering													
	P	SG	-	-	-	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-	-	-	-
552	Maintenance of Structures													
	P	SG	637,793	637,793	-	-	-	-	-	-	-	-	-	-
	P	SG	14,486	14,486	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-	-	-
			652,279	652,279	-	-	-	-	-	-	-	-	-	-
553	Maint of Generation & Electric Plant													
	P	SG	1,067,843	1,067,843	-	-	-	-	-	-	-	-	-	-
	P	SG	3,087,727	3,087,727	-	-	-	-	-	-	-	-	-	-
	P	SG	65,417	65,417	-	-	-	-	-	-	-	-	-	-
	P	SG	571,969	571,969	-	-	-	-	-	-	-	-	-	-
			4,792,956	4,792,956	-	-	-	-	-	-	-	-	-	-
554	Maintenance of Misc. Other													
	P	SG	571,642	571,642	-	-	-	-	-	-	-	-	-	-
	P	SG	280,792	280,792	-	-	-	-	-	-	-	-	-	-
	P	SG	20,931	20,931	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-	-	-
			873,365	873,365	-	-	-	-	-	-	-	-	-	-
	<b>Total Other Power Generation</b>		<b>94,323,065</b>	<b>94,323,065</b>	-	-	-	-	-	-	-	-	-	-
555	Purchased Power-Non NPC													
	P	S	-	-	-	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-	-	-	-
555NPC	Purchased Power-NPC													
	P	S	(430,221)	(430,221)	-	-	-	-	-	-	-	-	-	-
	P	SG	236,092,898	236,092,898	-	-	-	-	-	-	-	-	-	-
	P	SE	11,211,701	11,211,701	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-	-	-
	P	DGP	-	-	-	-	-	-	-	-	-	-	-	-
			246,874,378	246,874,378	-	-	-	-	-	-	-	-	-	-
	<b>Total Purchased Power</b>		<b>246,874,378</b>	<b>246,874,378</b>	-	-	-	-	-	-	-	-	-	-
556	System Control & Load Dispatch													
	P	SG	166,747	166,747	-	-	-	-	-	-	-	-	-	-
			166,747	166,747	-	-	-	-	-	-	-	-	-	-
557	Other Expenses													
	P	S	3,316,961	3,316,961	-	-	-	-	-	-	-	-	-	-
	P	SG	9,953,088	9,953,088	-	-	-	-	-	-	-	-	-	-
	P	SGCT	-	-	-	-	-	-	-	-	-	-	-	-
	P	SE	2,331	2,331	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-	-	-
	P	TROIP	-	-	-	-	-	-	-	-	-	-	-	-
			13,272,379	13,272,379	-	-	-	-	-	-	-	-	-	-
2017 Protocol Adjustment														
Baseline ECD	P	S	(11,000,000)	(11,000,000)	-	-	-	-	-	-	-	-	-	-
Equalization Adj.	P	S	-	-	-	-	-	-	-	-	-	-	-	-
			(11,000,000)	(11,000,000)	-	-	-	-	-	-	-	-	-	-
	<b>Total Other Power Supply</b>		<b>249,313,504</b>	<b>249,313,504</b>	-	-	-	-	-	-	-	-	-	-
<b>TOTAL PRODUCTION EXPENSE</b>			<b>593,750,196</b>	<b>593,750,196</b>	-	-	-	-	-	-	-	-	-	-
Embedded Cost Differentials														
Company Ownce	P	DGP	-	-	-	-	-	-	-	-	-	-	-	-
Company Ownce	P	SG	-	-	-	-	-	-	-	-	-	-	-	-
Mid-C Contract	P	MC	-	-	-	-	-	-	-	-	-	-	-	-
Mid-C Contract	P	SG	-	-	-	-	-	-	-	-	-	-	-	-
Existing QF Com	P	S	-	-	-	-	-	-	-	-	-	-	-	-
Existing QF Com	P	SG	-	-	-	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-	-	-	-
Hydro Endowment Fixed Dollar Proposal														
Klamath Surcharge Sit	P	S	-	-	-	-	-	-	-	-	-	-	-	-
ECD Hydro	P	S	-	-	-	-	-	-	-	-	-	-	-	-
Mid-C Contract	P	MC	-	-	-	-	-	-	-	-	-	-	-	-
Mid-C Contract	P	SG	-	-	-	-	-	-	-	-	-	-	-	-
Klamath Dam Remova	P	S	-	-	-	-	-	-	-	-	-	-	-	-
Less Klamath Surcharge Expense														
	P	SG	-	-	-	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-	-	-	-
560	Operation Supervision & Engineering													
	T	SG	2,469,731	-	2,469,731	-	-	-	-	-	-	-	-	-
	T	SG	(243)	-	(243)	-	-	-	-	-	-	-	-	-

				2,469,487	-	2,469,487	-	-	-	-	-	-	-
561	Load Dispatching	T	SG	4,872,252	-	4,872,252	-	-	-	-	-	-	-
		T	SG	(39)	-	(39)	-	-	-	-	-	-	-
				4,872,213	-	4,872,213	-	-	-	-	-	-	-
562	Station Expense	T	SG	884,923	-	884,923	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				884,923	-	884,923	-	-	-	-	-	-	-
563	Overhead Line Expense	T	SG	263,329	-	263,329	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				263,329	-	263,329	-	-	-	-	-	-	-
564	Underground Line Expense	T	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
565	Transmission of Electricity by Others-Non NPC	T	SG	-	-	-	-	-	-	-	-	-	-
		T	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
565NPC	Transmission of Electricity by Others-NPC	T	SG	38,695,804	-	38,695,804	-	-	-	-	-	-	-
		T	SE	3,105,531	-	3,105,531	-	-	-	-	-	-	-
				41,801,335	-	41,801,335	-	-	-	-	-	-	-
	Total Transmission of Electricity by Others			41,801,335	-	41,801,335	-	-	-	-	-	-	-
566	Misc. Transmission Expense	T	SG	984,585	-	984,585	-	-	-	-	-	-	-
		T	SG	(1,236,567)	-	(1,236,567)	-	-	-	-	-	-	-
				(251,982)	-	(251,982)	-	-	-	-	-	-	-
567	Rents - Transmission	T	SG	677,134	-	677,134	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				677,134	-	677,134	-	-	-	-	-	-	-
568	Maint Supervision & Engineering	T	SG	232,098	-	232,098	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				232,098	-	232,098	-	-	-	-	-	-	-
569	Maintenance of Structures	T	SG	1,459,608	-	1,459,608	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				1,459,608	-	1,459,608	-	-	-	-	-	-	-
570	Maintenance of Station Equipment	STEP_UP	SG	2,869,004	201,730	2,667,274	-	-	-	-	-	-	-
		STEP_UP	SG	(0)	(0)	(0)	-	-	-	-	-	-	-
				2,869,004	201,730	2,667,274	-	-	-	-	-	-	-
571	Maintenance of Overhead Lines	T	SG	4,962,816	-	4,962,816	-	-	-	-	-	-	-
		T	SG	249,552	-	249,552	-	-	-	-	-	-	-
				5,212,368	-	5,212,368	-	-	-	-	-	-	-
572	Maintenance of Underground Lines	T	SG	47,632	-	47,632	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				47,632	-	47,632	-	-	-	-	-	-	-
573	Maint of Misc. Transmission Plant	T	SG	50,024	-	50,024	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				50,024	-	50,024	-	-	-	-	-	-	-
	<b>TOTAL TRANSMISSION EXPENSE</b>			<b>60,587,175</b>	<b>201,730</b>	<b>60,385,445</b>	-	-	-	-	-	-	-
580	Operation Supervision & Engineering	D_SPLIT	S	453,473	-	-	429,677	5,234	-	-	18,562	-	-
		D_SPLIT	SNPD	2,269,622	-	-	2,150,526	26,194	-	-	92,902	-	-
				2,723,095	-	-	2,580,204	31,427	-	-	111,464	-	-
581	Load Dispatching	D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	3,549,774	-	-	3,549,774	-	-	-	-	-	-
				3,549,774	-	-	3,549,774	-	-	-	-	-	-
582	Station Expense	D	S	1,181,026	-	-	1,181,026	-	-	-	-	-	-
		D	SNPD	4,884	-	-	4,884	-	-	-	-	-	-
				1,185,910	-	-	1,185,910	-	-	-	-	-	-
583	Overhead Line Expenses	D	S	1,887,265	-	-	1,887,265	-	-	-	-	-	-
		D	SNPD	46	-	-	46	-	-	-	-	-	-
				1,887,312	-	-	1,887,312	-	-	-	-	-	-
584	Underground Line Expense	D	S	448	-	-	448	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				448	-	-	448	-	-	-	-	-	-
585	Street Lighting & Signal Systems	DL	S	-	-	-	-	-	-	-	-	-	-
		DL	SNPD	90,751	-	-	-	90,751	-	-	-	-	-
				90,751	-	-	-	90,751	-	-	-	-	-
586	Meter Expenses	C_Meter	S	1,347,604	-	-	-	-	-	-	1,347,604	-	-
		C_Meter	SNPD	-	-	-	-	-	-	-	-	-	-
				1,347,604	-	-	-	-	-	-	1,347,604	-	-
587	Customer Installation Expenses	D	S	6,725,086	-	-	6,725,086	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				6,725,086	-	-	6,725,086	-	-	-	-	-	-

588	Misc. Distribution Expenses	D	S	(122,388)	-	-	(122,388)	-	-	-	-	-	-
		D	SNPD	174,902	-	-	174,902	-	-	-	-	-	-
				52,513	-	-	52,513	-	-	-	-	-	-
589	Rents	D	S	2,010,384	-	-	2,010,384	-	-	-	-	-	-
		D	SNPD	7,210	-	-	7,210	-	-	-	-	-	-
				2,017,594	-	-	2,017,594	-	-	-	-	-	-
590	Maint Supervision & Engineering	D_SPLIT	S	870,564	-	-	824,882	10,047	-	-	35,635	-	-
		D_SPLIT	SNPD	712,784	-	-	675,381	8,226	-	-	29,176	-	-
				1,583,348	-	-	1,500,264	18,274	-	-	64,811	-	-
591	Maintenance of Structures	D	S	542,121	-	-	542,121	-	-	-	-	-	-
		D	SNPD	17,119	-	-	17,119	-	-	-	-	-	-
				559,240	-	-	559,240	-	-	-	-	-	-
592	Maintenance of Station Equipment	D	S	2,892,483	-	-	2,892,483	-	-	-	-	-	-
		D	SNPD	438,362	-	-	438,362	-	-	-	-	-	-
				3,330,846	-	-	3,330,846	-	-	-	-	-	-
593	Maintenance of Overhead Lines	D	S	81,068,804	-	-	81,068,804	-	-	-	-	-	-
		D	SNPD	897,936	-	-	897,936	-	-	-	-	-	-
				81,966,740	-	-	81,966,740	-	-	-	-	-	-
594	Maintenance of Underground Lines	D	S	7,588,671	-	-	7,588,671	-	-	-	-	-	-
		D	SNPD	6,531	-	-	6,531	-	-	-	-	-	-
				7,595,202	-	-	7,595,202	-	-	-	-	-	-
595	Maintenance of Line Transformers	D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	308,422	-	-	308,422	-	-	-	-	-	-
				308,422	-	-	308,422	-	-	-	-	-	-
596	Maint of Street Lighting & Signal Sys.	DL	S	734,147	-	-	-	734,147	-	-	-	-	-
		DL	SNPD	-	-	-	-	-	-	-	-	-	-
				734,147	-	-	-	734,147	-	-	-	-	-
597	Maintenance of Meters	C_Meter	S	227,348	-	-	-	-	-	-	227,348	-	-
		C_Meter	SNPD	8,148	-	-	-	-	-	-	8,148	-	-
				235,496	-	-	-	-	-	-	235,496	-	-
598	Maint of Misc. Distribution Plant	D	S	(271,211)	-	-	(271,211)	-	-	-	-	-	-
		D	SNPD	1,317,770	-	-	1,317,770	-	-	-	-	-	-
				1,046,559	-	-	1,046,559	-	-	-	-	-	-
	<b>TOTAL DISTRIBUTION EXPENSE</b>			<b>116,940,088</b>	-	-	<b>114,306,114</b>	<b>874,599</b>	-	-	<b>1,759,374</b>	-	-
901	Supervision	CUST901	S	-	-	-	-	-	-	-	-	-	-
		CUST901	CN	745,648	-	-	-	-	334,066	360,999	50,583	-	-
				745,648	-	-	-	-	334,066	360,999	50,583	-	-
902	Meter Reading Expense	C_Meter	S	2,480,518	-	-	-	-	-	-	2,480,518	-	-
		C_Meter	CN	128,242	-	-	-	-	-	-	128,242	-	-
				2,608,760	-	-	-	-	-	-	2,608,760	-	-
903	Customer Receipts & Collections	CUST903	S	813,440	-	-	-	-	545,411	46,814	221,214	-	-
		CUST903	CN	13,026,611	-	-	-	-	8,734,342	749,697	3,542,572	-	-
				13,840,051	-	-	-	-	9,279,753	796,511	3,763,786	-	-
904	Uncollectible Accounts	REVREQ	S	6,241,502	3,642,632	849,793	1,546,464	12,205	-	67,477	80,933	41,998	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		REVREQ	CN	48,229	28,147	6,566	11,950	94	-	521	625	325	-
				6,289,730	3,670,779	856,359	1,558,413	12,299	-	67,998	81,558	42,323	-
905	Misc. Customer Accounts Expense	CUST905	S	-	-	-	-	-	-	-	-	-	-
		CUST905	CN	8,701	-	-	-	-	-	-	-	8,701	-
				8,701	-	-	-	-	-	-	-	8,701	-
	<b>TOTAL CUSTOMER ACCOUNTS EXPENSE</b>			<b>23,492,890</b>	<b>3,670,779</b>	<b>856,359</b>	<b>1,558,413</b>	<b>12,299</b>	-	<b>9,681,818</b>	<b>3,847,829</b>	<b>3,865,393</b>	-
907	Supervision	C_Service	S	-	-	-	-	-	-	-	-	-	-
		C_Service	CN	950	-	-	-	-	-	-	-	950	-
				950	-	-	-	-	-	-	-	950	-
908	Customer Assistance	DSM	S	3,710,056	-	-	3,710,056	-	-	-	-	-	-
		C_Service	CN	661,150	-	-	-	-	-	-	-	661,150	-
				4,371,206	-	-	3,710,056	-	-	-	-	661,150	-
909	Informational & Instructional Adv	C_Service	S	793,001	-	-	-	-	-	-	-	793,001	-
		C_Service	CN	863,621	-	-	-	-	-	-	-	863,621	-
				1,656,622	-	-	-	-	-	-	-	1,656,622	-
910	Misc. Customer Service	C_Service	S	-	-	-	-	-	-	-	-	-	-
		C_Service	CN	598	-	-	-	-	-	-	-	598	-
				598	-	-	-	-	-	-	-	598	-
	<b>TOTAL CUSTOMER SERVICE EXPENSE</b>			<b>6,029,376</b>	-	-	<b>3,710,056</b>	-	-	-	-	<b>2,319,320</b>	-
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	-	-	-	-	-	-	-	-	-	-
<b>TOTAL SALES EXPENSE</b>				-	-	-	-	-	-	-	-	-	-
<b>Total Customer Service Exp Including Sales</b>				<b>6,029,376</b>	-	-	<b>3,710,056</b>	-	-	-	-	<b>2,319,320</b>	-
920	Administrative & General Salaries	LABOR	S	739,506	300,859	56,417	265,246	4,247	-	43,262	45,648	23,827	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	21,919,618	8,917,743	1,672,241	7,862,123	125,884	-	1,282,337	1,353,036	706,255	-
				22,659,124	9,218,602	1,728,657	8,127,368	130,131	-	1,325,599	1,398,684	730,082	-
921	Office Supplies & expenses	LABOR	S	1,944,169	790,963	148,320	697,334	11,165	-	113,737	120,008	62,642	-
		LABOR	CN	29,094	11,836	2,220	10,435	167	-	1,702	1,796	937	-
		LABOR	SO	2,755,810	1,121,169	210,240	988,453	15,827	-	161,220	170,108	88,793	-
				4,729,073	1,923,968	360,779	1,696,223	27,159	-	276,659	291,912	152,372	-
922	Office Supplies & expenses	LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(10,754,134)	(4,375,195)	(820,429)	(3,857,290)	(61,761)	-	(629,136)	(663,822)	(346,501)	-
				(10,754,134)	(4,375,195)	(820,429)	(3,857,290)	(61,761)	-	(629,136)	(663,822)	(346,501)	-
923	Outside Services	LABOR	S	239,952	97,622	18,306	86,066	1,378	-	14,038	14,812	7,731	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	6,447,326	2,623,020	491,864	2,313,525	37,027	-	377,180	397,975	207,734	-
				6,687,278	2,720,642	510,170	2,398,591	38,405	-	391,218	412,787	215,466	-
924	Property Insurance	DPW	S	11,847,293	-	-	11,470,299	-	-	-	376,994	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
		GP	SO	981,641	418,318	235,688	298,744	3,683	-	5,493	16,113	3,601	-
				12,828,933	418,318	235,688	11,769,042	3,683	-	5,493	393,107	3,601	-
925	Injuries & Damages	DPW	S	1,608,709	-	-	1,557,518	-	-	-	51,191	-	-
		LABOR	SO	8,980,098	3,653,449	685,089	3,220,979	51,573	-	525,352	554,316	289,341	-
				10,588,807	3,653,449	685,089	4,778,497	51,573	-	525,352	605,507	289,341	-
926	Employee Pensions & Benefits	LABOR	S	174,360	70,936	13,302	62,539	1,001	-	10,200	10,763	5,618	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	32,482,216	13,215,013	2,478,058	11,650,712	186,545	-	1,900,267	2,005,036	1,046,584	-
				32,656,576	13,285,950	2,491,360	11,713,252	187,547	-	1,910,468	2,015,798	1,052,202	-
927	Franchise Requirements	DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
928	Regulatory Commission Expense	D	S	6,019,755	-	-	6,019,755	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		D	SO	654,867	-	-	654,867	-	-	-	-	-	-
		FERC	SG	1,206,779	485,160	721,618	-	-	-	-	-	-	-
				7,881,401	485,160	721,618	6,674,622	-	-	-	-	-	-
929	Duplicate Charges	LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(34,071,021)	(13,861,400)	(2,599,267)	(12,220,584)	(195,670)	-	(1,993,215)	(2,103,108)	(1,097,776)	-
				(34,071,021)	(13,861,400)	(2,599,267)	(12,220,584)	(195,670)	-	(1,993,215)	(2,103,108)	(1,097,776)	-
930	Misc General Expenses	LABOR	S	(1,669,716)	(679,305)	(127,382)	(598,893)	(9,589)	-	(97,681)	(103,067)	(53,799)	-
		C_SERVICE	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	488,157	198,601	37,241	175,092	2,803	-	28,558	30,133	15,729	-
				(1,181,559)	(480,704)	(90,141)	(423,801)	(6,786)	-	(69,123)	(72,934)	(38,070)	-
931	Rents	LABOR	S	490,906	199,719	37,451	176,078	2,819	-	28,719	30,302	15,817	-
		LABOR	SO	604,360	245,877	46,106	216,772	3,471	-	35,356	37,305	19,473	-
				1,095,266	445,596	83,557	392,850	6,290	-	64,075	67,608	35,290	-
935	Maintenance of General Plant	G	S	157,258	32,080	56,917	64,057	-	-	2,098	2,105	-	-
		B_Center	CN	9,015	-	-	-	-	-	5,873	-	3,142	-
		G	SO	7,456,823	1,521,166	2,698,884	3,037,444	-	-	99,498	99,832	-	-
				7,623,096	1,533,246	2,755,801	3,101,501	-	-	107,469	101,937	3,142	-
<b>TOTAL ADMINISTRATIVE &amp; GEN EXPENSE</b>				<b>60,742,837</b>	<b>14,987,633</b>	<b>6,062,882</b>	<b>34,150,269</b>	<b>180,571</b>	-	<b>1,914,858</b>	<b>2,447,475</b>	<b>999,149</b>	-
<b>TOTAL O&amp;M EXPENSE</b>				<b>861,542,561</b>	<b>612,610,337</b>	<b>67,304,687</b>	<b>153,724,852</b>	<b>1,067,470</b>	-	<b>11,596,676</b>	<b>8,054,679</b>	<b>7,183,862</b>	-
403SP	Steam Depreciation	P	SG	10,537,740	10,537,740	-	-	-	-	-	-	-	-
		P	SG	8,762,657	8,762,657	-	-	-	-	-	-	-	-
		P	SG	94,925,664	94,925,664	-	-	-	-	-	-	-	-
		P	SG	1,978,660	1,978,660	-	-	-	-	-	-	-	-
				116,204,721	116,204,721	-	-	-	-	-	-	-	-
403NP	Nuclear Depreciation	P	SG	-	-	-	-	-	-	-	-	-	-
403HP	Hydro Depreciation	P	SG	(6,305,162)	(6,305,162)	-	-	-	-	-	-	-	-
		P	SG	351,595	351,595	-	-	-	-	-	-	-	-
		P	SG	12,762,530	12,762,530	-	-	-	-	-	-	-	-
		P	SG	2,289,221	2,289,221	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				9,098,184	9,098,184	-	-	-	-	-	-	-	-







	D	SNPD	-	-	-	-	-	-	-	-	-	-
	CSS_SYS	CN	3,715	-	-	-	-	1,647	867	1,201	-	-
	P	SGCT	-	-	-	-	-	-	-	-	-	-
	BOOKDEPR	SCHMDEXP	(65,230,979)	(43,657,551)	(8,804,824)	(12,136,930)	(171,847)	(60,921)	(398,904)	-	-	-
	P	TROJD	(0)	(0)	-	-	-	-	-	-	-	-
	IBT	IBT	-	-	-	-	-	-	-	-	-	-
	P	SG	(151,206)	(151,206)	-	-	-	-	-	-	-	-
	GP	GPS	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
			(98,423,188)	(55,973,287)	(15,263,838)	(25,354,440)	(333,801)	(257,194)	(1,120,189)	(120,438)	-	-
TOTAL DEFERRED INCOME TAXES			12,660,019	10,316,399	8,177,502	(5,882,254)	(268,741)	406,528	(390,854)	301,439	-	-
SCHMAF	Additions - Flow Through		-	-	-	-	-	-	-	-	-	-
	SCHMAF	S	-	-	-	-	-	-	-	-	-	-
	SCHMAF	SNP	-	-	-	-	-	-	-	-	-	-
	SCHMAF	SO	-	-	-	-	-	-	-	-	-	-
	SCHMAF	SE	-	-	-	-	-	-	-	-	-	-
	P	TROJP	-	-	-	-	-	-	-	-	-	-
	SCHMAF	SG	-	-	-	-	-	-	-	-	-	-
SCHMAP	Additions - Permanent		-	-	-	-	-	-	-	-	-	-
	P	S	-	-	-	-	-	-	-	-	-	-
	P	SE	11,270	11,270	-	-	-	-	-	-	-	-
	PTD	SNP	-	-	-	-	-	-	-	-	-	-
	SCHMAP-SO	SO	794,541	600,654	24,937	117,242	1,877	19,123	20,177	10,532	-	-
	SCHMAP	SG	-	-	-	-	-	-	-	-	-	-
	BOOKDEPR	SCHMDEXP	29,259	19,583	3,949	5,444	77	27	179	-	-	-
			835,071	631,507	28,886	122,686	1,954	19,150	20,356	10,532	-	-
SCHMAT	Additions - Temporary		-	-	-	-	-	-	-	-	-	-
	SCHMAT-SITUS	S	15,340,473	15,425,597	(70,870)	(30,667)	690	7,031	4,821	3,872	-	-
	SCHMAT-SG	GPS	-	-	-	-	-	-	-	-	-	-
	D SPLIT	CIAC	22,664,151	-	-	21,474,876	261,569	-	927,706	-	-	-
	SCHMAT-SNP	SNP	18,237,871	8,434,033	4,880,163	4,766,173	-	395	156,837	269	-	-
	P	TROJD	0	0	-	-	-	-	-	-	-	-
	C BILLING	BADDEBT	0	-	-	-	-	0	-	-	-	-
	SCHMAT-SE	SE	4,243,195	4,238,254	636	2,988	48	487	514	268	-	-
	SCHMAT-SG	GPS	-	-	-	-	-	-	-	-	-	-
	CSS_SYS	CN	(15,111)	-	-	-	-	(6,699)	(3,526)	(4,886)	-	-
	SCHMAT-SO	SO	4,956,187	2,011,392	361,020	1,786,382	28,976	295,172	310,678	162,568	-	-
	SCHMAT-SNP	SNPD	(0)	(0)	(0)	(0)	-	(0)	(0)	(0)	-	-
	P	SGCT	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
	BOOKDEPR	SCHMDEXP	265,311,099	177,566,445	35,811,476	49,364,005	698,946	247,782	1,622,445	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
	P	SG	1,809,483	1,809,483	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
			332,547,348	209,485,203	40,982,425	77,363,758	990,229	544,168	3,019,475	162,091	-	-
TOTAL SCHEDULE - M ADDITIONS			333,382,419	210,116,710	41,011,311	77,486,444	992,183	563,317	3,039,831	172,623	-	-
SCHMDF	Deductions - Flow Through		-	-	-	-	-	-	-	-	-	-
	SCHMDF	S	-	-	-	-	-	-	-	-	-	-
	SCHMDF	SG	-	-	-	-	-	-	-	-	-	-
	SCHMDF	SG	-	-	-	-	-	-	-	-	-	-
SCHMDP	Deductions - Permanent		-	-	-	-	-	-	-	-	-	-
	SCHMDP	S	-	-	-	-	-	-	-	-	-	-
	P	SE	276,091	276,091	-	-	-	-	-	-	-	-
	SCHMDP	SNP	27,630	27,379	125	122	-	-	4	-	-	-
	BOOKDEPR	SCHMDEXP	-	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
	SCHMDP-SO	SO	-	-	-	-	-	-	-	-	-	-
			303,721	303,470	125	122	-	-	4	-	-	-
SCHMDT	Deductions - Temporary		-	-	-	-	-	-	-	-	-	-
	SCHMDT-SITUS	S	1,645,989	1,800,312	(39,678)	(97,892)	(558)	(5,944)	(6,945)	(3,306)	-	-
	SCHMDT	BADDEBT	-	-	-	-	-	-	-	-	-	-
	SCHMDT-SNP	SNP	30,203,376	13,970,129	8,081,434	7,892,413	-	-	259,400	-	-	-
	SCHMDT	CN	-	-	-	-	-	-	-	-	-	-
	SCHMDT-SG	SG	541,305	541,195	110	-	-	-	-	-	-	-
	SCHMDT-SG	SG	36,247,278	36,239,911	7,367	-	-	-	-	-	-	-
	P	SE	38,359	38,359	-	-	-	-	-	-	-	-
	SCHMDT-SG	SG	-	-	-	-	-	-	-	-	-	-
	SCHMDT-GPS	GPS	13,305,510	6,154,269	3,560,119	3,476,849	-	-	114,273	-	-	-
	SCHMDT-SO	SO	7,315,999	2,591,587	(1,646,815)	3,189,141	119,182	1,212,146	1,183,411	667,349	-	-
	TAXDEPR	TAXDEPR	362,506,031	225,507,148	68,340,946	63,397,020	72,450	2,105,225	1,707,806	1,375,437	-	-
	SCHMDT-SNP	SNPD	-	-	-	-	-	-	-	-	-	-
			451,803,847	286,842,910	78,303,483	77,857,530	191,073	3,311,427	3,257,945	2,039,479	-	-
TOTAL SCHEDULE - M DEDUCTIONS			452,107,568	287,146,380	78,303,607	77,857,652	191,073	3,311,427	3,257,949	2,039,479	-	-
TOTAL SCHEDULE - M ADJUSTMENTS			(118,725,149)	(77,029,670)	(37,292,296)	(371,208)	801,110	(2,748,109)	(218,118)	(1,866,856)	-	-
40911	State Income Taxes		-	-	-	-	-	-	-	-	-	-
	REVREQ	S	(1,615,210)	(942,660)	(219,914)	(400,202)	(3,159)	(17,462)	(20,944)	(10,869)	-	-
	PTC	SG	5,845,636	3,411,599	795,895	1,448,380	11,431	63,197	75,800	39,334	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
	IBT	IBT	-	-	-	-	-	-	-	-	-	-
TOTAL STATE TAXES			4,230,426	2,468,939	575,981	1,048,177	8,273	45,735	54,856	28,466	-	-
Calculation of Taxable Income:			-	-	-	-	-	-	-	-	-	-
Operating Revenues			1,422,789,617	830,360,932	193,715,609	352,526,128	2,782,247	15,381,774	18,449,194	9,573,734	-	-
Operating Deductions:			-	-	-	-	-	-	-	-	-	-
O & M Expenses			861,542,561	612,610,337	67,304,687	153,724,852	1,067,470	11,596,676	8,054,679	7,183,862	-	-
Depreciation Expense			287,994,295	184,502,530	40,225,922	58,597,189	829,712	550,435	2,988,279	300,228	-	-
Amortization Expense			43,237,301	5,795,483	1,660,641	29,375,575	45,969	2,363,170	2,356,565	1,639,897	-	-
Taxes Other Than Income			84,171,808	24,456,422	12,622,760	45,488,639	196,642	321,645	876,129	209,570	-	-
Interest & Dividends (AFUDC-Equity)			(21,356,078)	(9,100,725)	(5,127,508)	(6,499,315)	(80,130)	(119,505)	(350,552)	(78,343)	-	-
Misc Revenue & Expense			3,165	(507,960)	(208)	511,333	-	-	-	-	-	-
Total Operating Deductions			1,255,593,052	817,756,088	116,686,293	281,198,273	2,059,664	14,712,421	13,925,100	9,255,214	-	-
Other Deductions:			-	-	-	-	-	-	-	-	-	-
Interest Deductions			84,048,729	32,525,127	25,323,444	24,006,986	261,721	229,959	1,562,708	138,784	-	-
Interest on PCRBS			-	-	-	-	1	-	-	-	-	-
Schedule M Adjustments			(118,725,149)	(77,029,670)	(37,292,296)	(371,208)	801,110	(2,748,109)	(218,118)	(1,866,856)	-	-
Income Before State Taxes			(35,577,313)	(96,949,953)	14,413,575	46,949,660	1,261,971	(2,308,715)	2,743,267	(1,687,120)	-	-

State Income Taxes			4,230,426	2,468,939	575,981	1,048,177	8,273	-	45,735	54,856	28,466	-
<b>Total Taxable Income</b>			<b>(39,807,739)</b>	<b>(99,418,892)</b>	<b>13,837,595</b>	<b>45,901,483</b>	<b>1,253,699</b>	<b>-</b>	<b>(2,354,450)</b>	<b>2,688,411</b>	<b>(1,715,586)</b>	<b>-</b>
Tax Rate			21%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
Federal Income Tax - Calculated			(8,359,625.19)	(20,877,967)	2,905,895	9,639,311	263,277	-	(494,435)	564,566	(360,273)	-
Adjustments to Calculated Tax:												
40910 PMI	P	SE	(4,262)	(4,262)	-	-	-	-	-	-	-	-
40910 Renewable Energy Cre	P	SG	(52,932,259)	(52,932,259)	-	-	-	-	-	-	-	-
40910	P	SO	-	-	-	-	-	-	-	-	-	-
40910	P	S	-	-	-	-	-	-	-	-	-	-
Federal Income Tax			(61,296,146)	(73,814,488)	2,905,895	9,639,311	263,277	-	(494,435)	564,566	(360,273)	-
<b>TOTAL OPERATING EXPENSES</b>			<b>1,232,543,429</b>	<b>765,827,662</b>	<b>133,473,180</b>	<b>292,502,823</b>	<b>2,142,601</b>	<b>-</b>	<b>14,789,754</b>	<b>14,504,220</b>	<b>9,303,189</b>	<b>-</b>
310 Land and Land Rights												
	P	SG	606,665	606,665	-	-	-	-	-	-	-	-
	P	SG	8,821,544	8,821,544	-	-	-	-	-	-	-	-
	P	SG	14,127,229	14,127,229	-	-	-	-	-	-	-	-
	P	S	-	-	-	-	-	-	-	-	-	-
	P	SG	330,272	330,272	-	-	-	-	-	-	-	-
			23,885,710	23,885,710	-	-	-	-	-	-	-	-
311 Structures and Improvements												
	P	SG	58,997,716	58,997,716	-	-	-	-	-	-	-	-
	P	SG	81,647,008	81,647,008	-	-	-	-	-	-	-	-
	P	SG	119,488,091	119,488,091	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
			260,132,815	260,132,815	-	-	-	-	-	-	-	-
312 Boiler Plant Equipment												
	P	SG	152,960,616	152,960,616	-	-	-	-	-	-	-	-
	P	SG	121,218,558	121,218,558	-	-	-	-	-	-	-	-
	P	SG	872,591,337	872,591,337	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
			1,146,770,511	1,146,770,511	-	-	-	-	-	-	-	-
314 Turbogenerator Units												
	P	SG	28,423,848	28,423,848	-	-	-	-	-	-	-	-
	P	SG	28,456,627	28,456,627	-	-	-	-	-	-	-	-
	P	SG	189,633,289	189,633,289	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
			246,513,764	246,513,764	-	-	-	-	-	-	-	-
315 Accessory Electric Equipment												
	P	SG	22,358,913	22,358,913	-	-	-	-	-	-	-	-
	P	SG	34,705,893	34,705,893	-	-	-	-	-	-	-	-
	P	SG	53,367,895	53,367,895	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
			110,432,701	110,432,701	-	-	-	-	-	-	-	-
316 Misc Power Plant Equipment												
	P	SG	612,221	612,221	-	-	-	-	-	-	-	-
	P	SG	1,280,790	1,280,790	-	-	-	-	-	-	-	-
	P	SG	6,188,421	6,188,421	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
			8,081,432	8,081,432	-	-	-	-	-	-	-	-
317 Steam Plant ARO												
	P	S	-	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-	-
SP Unclassified Steam Plant - Account 300												
	P	SG	14,918,787	14,918,787	-	-	-	-	-	-	-	-
			14,918,787	14,918,787	-	-	-	-	-	-	-	-
<b>Total Steam Production Plant</b>			<b>1,810,735,721</b>	<b>1,810,735,721</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
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 - Aect 300												
	P	SG	-	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-	-
<b>Total Nuclear Production Plant</b>			<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
330 Land and Land Rights												
	P	SG	2,693,685	2,693,685	-	-	-	-	-	-	-	-
	P	SG	1,373,470	1,373,470	-	-	-	-	-	-	-	-
	P	SG	5,726,355	5,726,355	-	-	-	-	-	-	-	-
	P	SG	343,282	343,282	-	-	-	-	-	-	-	-



	P	SG	(144,214)	(144,214)	-	-	-	-	-	-	-
			(144,214)	(144,214)	-	-	-	-	-	-	-
<b>Total Other Production Plant</b>			<b>1,380,116,672</b>	<b>1,380,116,672</b>	-	-	-	-	-	-	-
Experimental Plant 103 Experimental Plant	P	SG	-	-	-	-	-	-	-	-	-
<b>Total Experimental Plant</b>			<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
<b>TOTAL PRODUCTION PLANT</b>			<b>3,512,492,308</b>	<b>3,512,492,308</b>	-	-	-	-	-	-	-
350 Land and Land Rights											
	T	SG	5,470,988	-	5,470,988	-	-	-	-	-	-
	T	SG	12,300,087	-	12,300,087	-	-	-	-	-	-
	T	SG	63,014,302	-	63,014,302	-	-	-	-	-	-
			80,785,377	-	80,785,377	-	-	-	-	-	-
352 Structures and Improvements											
	T	S	-	-	-	-	-	-	-	-	-
	T	SG	1,811,625	-	1,811,625	-	-	-	-	-	-
	T	SG	4,607,410	-	4,607,410	-	-	-	-	-	-
	T	SG	75,127,254	-	75,127,254	-	-	-	-	-	-
			81,546,289	-	81,546,289	-	-	-	-	-	-
353 Station Equipment											
	STEP_UP	SG	27,253,570	1,916,294	25,337,276	-	-	-	-	-	-
	STEP_UP	SG	39,679,893	2,790,033	36,889,860	-	-	-	-	-	-
	STEP_UP	SG	543,548,929	38,218,838	505,330,091	-	-	-	-	-	-
			610,482,392	42,925,165	567,557,227	-	-	-	-	-	-
354 Towers and Fixtures											
	T	SG	33,397,707	-	33,397,707	-	-	-	-	-	-
	T	SG	34,209,839	-	34,209,839	-	-	-	-	-	-
	T	SG	280,025,120	-	280,025,120	-	-	-	-	-	-
			347,632,667	-	347,632,667	-	-	-	-	-	-
355 Poles and Fixtures											
	T	S	-	-	-	-	-	-	-	-	-
	T	SG	15,608,667	-	15,608,667	-	-	-	-	-	-
	T	SG	29,621,536	-	29,621,536	-	-	-	-	-	-
	T	SG	324,275,026	-	324,275,026	-	-	-	-	-	-
			369,505,228	-	369,505,228	-	-	-	-	-	-
356 Clearing and Grading											
	T	SG	41,055,979	-	41,055,979	-	-	-	-	-	-
	T	SG	40,970,698	-	40,970,698	-	-	-	-	-	-
	T	SG	277,503,823	-	277,503,823	-	-	-	-	-	-
			359,530,500	-	359,530,500	-	-	-	-	-	-
357 Underground Conduit											
	T	SG	1,661	-	1,661	-	-	-	-	-	-
	T	SG	23,894	-	23,894	-	-	-	-	-	-
	T	SG	980,230	-	980,230	-	-	-	-	-	-
			1,005,785	-	1,005,785	-	-	-	-	-	-
358 Underground Conductors											
	T	SG	-	-	-	-	-	-	-	-	-
	T	SG	283,529	-	283,529	-	-	-	-	-	-
	T	SG	2,083,819	-	2,083,819	-	-	-	-	-	-
			2,367,348	-	2,367,348	-	-	-	-	-	-
359 Roads and Trails											
	T	SG	485,699	-	485,699	-	-	-	-	-	-
	T	SG	114,843	-	114,843	-	-	-	-	-	-
	T	SG	2,565,965	-	2,565,965	-	-	-	-	-	-
			3,166,507	-	3,166,507	-	-	-	-	-	-
TP Unclassified Trans Plant - Acct 300											
	T	SG	241,036,512	-	241,036,512	-	-	-	-	-	-
			241,036,512	-	241,036,512	-	-	-	-	-	-
TS0 Unclassified Trans Sub Plant - Acct 300											
	T	SG	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-
<b>TOTAL TRANSMISSION PLANT</b>			<b>2,097,058,605</b>	<b>42,925,165</b>	<b>2,054,133,440</b>	-	-	-	-	-	-
360 Land and Land Rights											
	D	S	15,341,593	-	15,341,593	-	-	-	-	-	-
			15,341,593	-	15,341,593	-	-	-	-	-	-
361 Structures and Improvements											
	D	S	34,602,903	-	34,602,903	-	-	-	-	-	-
			34,602,903	-	34,602,903	-	-	-	-	-	-
362 Station Equipment											
	D	S	278,426,317	-	278,426,317	-	-	-	-	-	-
			278,426,317	-	278,426,317	-	-	-	-	-	-
363 Storage Battery Equipment											
	D	S	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-
364 Poles, Towers & Fixtures											
	D	S	473,552,029	-	473,552,029	-	-	-	-	-	-
			473,552,029	-	473,552,029	-	-	-	-	-	-
365 Overhead Conductors											
	D	S	313,370,002	-	313,370,002	-	-	-	-	-	-
			313,370,002	-	313,370,002	-	-	-	-	-	-
366 Underground Conduit											
	D	S	113,316,773	-	113,316,773	-	-	-	-	-	-
			113,316,773	-	113,316,773	-	-	-	-	-	-
367 Underground Conductors											
	D	S	223,703,231	-	223,703,231	-	-	-	-	-	-
			223,703,231	-	223,703,231	-	-	-	-	-	-
368 Line Transformers											
	D	S	521,925,966	-	521,925,966	-	-	-	-	-	-
			521,925,966	-	521,925,966	-	-	-	-	-	-

369	Services	D	S	340,242,418	-	-	340,242,418	-	-	-	-	-	-
				340,242,418	-	-	340,242,418	-	-	-	-	-	-
370	Meters	C_Meter	S	101,685,442	-	-	-	-	-	-	101,685,442	-	-
				101,685,442	-	-	-	-	-	-	101,685,442	-	-
371	Installations on Customers' Premises	DL	S	2,803,506	-	-	-	2,803,506	-	-	-	-	-
				2,803,506	-	-	-	2,803,506	-	-	-	-	-
372	Leased Property	D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
373	Street Lights	DL	S	25,866,963	-	-	-	25,866,963	-	-	-	-	-
				25,866,963	-	-	-	25,866,963	-	-	-	-	-
DP	Unclassified Dist Plant - Acct 300	D	S	39,370,985	-	-	39,370,985	-	-	-	-	-	-
				39,370,985	-	-	39,370,985	-	-	-	-	-	-
DS0	Unclassified Dist Sub Plant - Acct 300	D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	<b>TOTAL DISTRIBUTION PLANT</b>			<b>2,484,208,127</b>	-	-	<b>2,353,852,216</b>	<b>28,670,469</b>	-	-	<b>101,685,442</b>	-	-
389	Land and Land Rights	D_SPLIT	S	6,116,556	-	-	5,795,597	70,592	-	-	250,367	-	-
		B_Center	CN	349,723	-	-	-	-	-	227,826	-	121,897	-
		G-DGU	SG	87	55	32	-	-	-	-	-	-	-
		G-SG	SG	320	132	188	-	-	-	-	-	-	-
		LABOR	SO	2,068,311	841,468	157,791	741,861	11,878	-	121,000	127,671	66,641	-
				8,534,997	841,655	158,011	6,537,458	82,470	-	348,826	378,038	188,539	-
390	Structures and Improvements	D_SPLIT	S	40,901,786	-	-	38,755,513	472,051	-	-	1,674,222	-	-
		P	SE	222,614	222,614	-	-	-	-	-	-	-	-
		G-DGP	SG	87,398	55,368	32,030	-	-	-	-	-	-	-
		G-DGU	SG	353,615	224,022	129,593	-	-	-	-	-	-	-
		B_Center	CN	2,543,565	-	-	-	-	-	1,656,995	-	886,570	-
		G-SG	SG	2,709,338	1,114,891	1,594,448	-	-	-	-	-	-	-
		LABOR	SO	27,551,225	11,208,897	2,101,874	9,882,066	158,227	-	1,611,796	1,700,659	887,707	-
				74,369,541	12,825,791	3,857,945	48,637,579	630,278	-	3,268,791	3,374,882	1,774,277	-
391	Office Furniture & Equipment	D_SPLIT	S	2,404,388	-	-	2,278,221	27,749	-	-	98,418	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	1,248,381	-	-	-	-	-	813,253	-	435,128	-
		G-SG	SG	1,072,760	441,440	631,320	-	-	-	-	-	-	-
		P	SE	8,010	8,010	-	-	-	-	-	-	-	-
		LABOR	SO	16,512,388	6,717,874	1,259,725	5,922,659	94,831	-	966,004	1,019,263	532,033	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	1,053	1,053	-	-	-	-	-	-	-	-
				21,246,980	7,168,377	1,891,045	8,200,880	122,580	-	1,779,257	1,117,681	967,161	-
392	Transportation Equipment	D_SPLIT	S	26,003,370	-	-	24,638,873	300,107	-	-	1,064,389	-	-
		LABOR	SO	2,109,964	858,414	160,968	756,801	12,118	-	123,437	130,242	67,984	-
		G-SG	SG	6,134,374	2,524,290	3,610,084	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	104,592	66,261	38,331	-	-	-	-	-	-	-
		P	SE	82,063	82,063	-	-	-	-	-	-	-	-
		G-DGP	SG	18,410	11,663	6,747	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	11,642	11,642	-	-	-	-	-	-	-	-
				34,464,413	3,554,333	3,816,130	25,395,674	312,225	-	123,437	1,194,631	67,984	-
393	Stores Equipment	D_SPLIT	S	2,735,814	-	-	2,592,255	31,574	-	-	111,984	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	67,548	27,481	5,153	24,228	388	-	3,952	4,170	2,176	-
		G-SG	SG	1,566,389	644,568	921,821	-	-	-	-	-	-	-
		P	SG	14,070	14,070	-	-	-	-	-	-	-	-
				4,383,821	686,120	926,975	2,616,483	31,962	-	3,952	116,154	2,176	-
394	Tools, Shop & Garage Equipment	D_SPLIT	S	10,914,668	-	-	10,341,934	125,967	-	-	446,767	-	-
		G-DGP	SG	9,824	6,224	3,600	-	-	-	-	-	-	-
		G-SG	SG	5,654,511	2,326,827	3,327,685	-	-	-	-	-	-	-
		LABOR	SO	532,529	216,653	40,626	191,007	3,058	-	31,154	32,872	17,158	-
		P	SE	31,508	31,508	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	23,441	23,441	-	-	-	-	-	-	-	-
				17,166,482	2,604,653	3,371,911	10,532,941	129,025	-	31,154	479,639	17,158	-
395	Laboratory Equipment	D_SPLIT	S	9,565,368	-	-	9,063,437	110,395	-	-	391,537	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	1,324,126	538,705	101,017	474,937	7,604	-	77,464	81,735	42,664	-
		P	SE	336,723	336,723	-	-	-	-	-	-	-	-
		G-SG	SG	1,680,922	691,698	989,224	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	3,655	3,655	-	-	-	-	-	-	-	-
				12,910,795	1,570,782	1,090,241	9,538,374	117,999	-	77,464	473,271	42,664	-
396	Power Operated Equipment	D_SPLIT	S	44,851,927	-	-	42,498,374	517,640	-	-	1,835,912	-	-
		G-DGP	SG	68,304	43,272	25,032	-	-	-	-	-	-	-
		G-SG	SG	11,773,951	4,844,971	6,928,980	-	-	-	-	-	-	-
		LABOR	SO	2,265,084	921,523	172,803	812,440	13,008	-	132,511	139,817	72,982	-
		G-DGU	SG	241,105	152,745	88,361	-	-	-	-	-	-	-
		P	SE	59,333	59,333	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				59,259,704	6,021,844	7,215,175	43,310,814	530,648	-	132,511	1,975,729	72,982	-
397	Communication Equipment												



				-	1,762,429	(562,535)	(1,126,001)	-	-	(36,884)	(37,008)	-	-
114	Electric Plant Acquisition Adjustments												
	P	S		-	-	-	-	-	-	-	-	-	-
	P	SG		917,274	917,274	-	-	-	-	-	-	-	-
	P	SG		-	-	-	-	-	-	-	-	-	-
				917,274	917,274	-	-	-	-	-	-	-	-
115	Accum Provision for Asset Acquisition Adjustments												
	P	S		-	-	-	-	-	-	-	-	-	-
	P	SG		(215,669)	(215,669)	-	-	-	-	-	-	-	-
	P	SG		-	-	-	-	-	-	-	-	-	-
				(215,669)	(215,669)	-	-	-	-	-	-	-	-
128	Pensions	LABOR	SO	-	-	-	-	-	-	-	-	-	-
124	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
182W	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
186W	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	CN	-	-	-	-	-	-	-	-	-	-
		DSM	CNP	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Total Weatherization			-	-	-	-	-	-	-	-	-	-
151	Fuel Stock												
	P	DEU		-	-	-	-	-	-	-	-	-	-
	P	SE		44,556,924	44,556,924	-	-	-	-	-	-	-	-
	P	SE		-	-	-	-	-	-	-	-	-	-
	P	SE		-	-	-	-	-	-	-	-	-	-
				44,556,924	44,556,924	-	-	-	-	-	-	-	-
152	Fuel Stock - Undistributed												
	P	SE		-	-	-	-	-	-	-	-	-	-
25316	DG&T Working Capital Deposit												
	P	SE		(702,660)	(702,660)	-	-	-	-	-	-	-	-
				(702,660)	(702,660)	-	-	-	-	-	-	-	-
25317	DG&T Working Capital Deposit												
	P	SE		(662,138)	(662,138)	-	-	-	-	-	-	-	-
				(662,138)	(662,138)	-	-	-	-	-	-	-	-
25319	Provo Working Capital Deposit												
	P	SE		-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Total Fuel Stock			43,192,126	43,192,126	-	-	-	-	-	-	-	-
154	Materials and Supplies												
	MSS	S		49,096,450	40,104,956	726,333	8,002,154	-	-	-	263,007	-	-
	MSS	SG		(131,544)	(107,453)	(1,946)	(21,440)	-	-	-	(705)	-	-
	MSS	SE		-	-	-	-	-	-	-	-	-	-
	MSS	SO		(348,970)	(285,060)	(5,163)	(56,878)	-	-	-	(1,869)	-	-
	MSS	SG		31,321,653	25,585,425	463,373	5,105,068	-	-	-	167,788	-	-
	MSS	SG		2,074	1,694	31	338	-	-	-	11	-	-
	MSS	SNPD		(346,469)	(283,017)	(5,126)	(56,470)	-	-	-	(1,856)	-	-
	MSS	SG		-	-	-	-	-	-	-	-	-	-
	MSS	SG		-	-	-	-	-	-	-	-	-	-
	MSS	SG		-	-	-	-	-	-	-	-	-	-
	MSS	SG		-	-	-	-	-	-	-	-	-	-
	MSS	SG		2,197,788	1,795,286	32,514	358,214	-	-	-	11,773	-	-
	MSS	SG		-	-	-	-	-	-	-	-	-	-
				81,790,983	66,811,832	1,210,017	13,330,985	-	-	-	438,149	-	-
163	Stores Expense Undistributed												
	MSS	SO		-	-	-	-	-	-	-	-	-	-
25318	Provo Working Capital Deposit												
	MSS	SG		(71,172)	(58,138)	(1,053)	(11,600)	-	-	-	(381)	-	-
				(71,172)	(58,138)	(1,053)	(11,600)	-	-	-	(381)	-	-
	Total Materials & Supplies			81,719,811	66,753,694	1,208,964	13,319,385	-	-	-	437,768	-	-
165	Prepayments												
	LABOR	S		4,077,479	1,658,875	311,070	1,462,509	23,417	-	238,540	251,691	131,377	-
	GP	GPS		43,521	18,546	10,449	13,245	163	-	244	714	160	-
	PT	SG		999,612	625,920	373,692	-	-	-	-	-	-	-
	P	SE		11,465	11,465	-	-	-	-	-	-	-	-
	LABOR	SO		5,997,840	2,440,152	457,573	2,151,304	34,446	-	350,884	370,230	193,252	-
				11,129,917	4,754,958	1,152,784	3,627,057	58,026	-	589,668	622,635	324,789	-
182M	Misc Regulatory Assets												
	DDS2	S		-	-	-	-	-	-	-	-	-	-
	DEFSG	SG		611,240	560,054	51,186	-	-	-	-	-	-	-
	P	SGCT		-	-	-	-	-	-	-	-	-	-
	DEFSG	SG		-	-	-	-	-	-	-	-	-	-
	P	SE		28,858,211	28,858,211	-	-	-	-	-	-	-	-
	P	SG		-	-	-	-	-	-	-	-	-	-
	LABOR	SO		12,446,039	5,063,527	949,504	4,464,142	71,478	-	728,115	768,259	401,014	-
				41,915,490	34,481,792	1,000,690	4,464,142	71,478	-	728,115	768,259	401,014	-
186M	Misc Deferred Debits												
	LABOR	S		-	-	-	-	-	-	-	-	-	-
	P	SG		-	-	-	-	-	-	-	-	-	-
	P	SG		-	-	-	-	-	-	-	-	-	-
	DEFSG	SG		25,160,668	23,053,690	2,106,978	-	-	-	-	-	-	-

	LABOR	SO	21,299	8,665	1,625	7,640	122	-	1,246	1,315	686	-
	P	SE	202,872	202,872	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-	-
	GP	EXCTAX	-	-	-	-	-	-	-	-	-	-
			25,384,840	23,265,227	2,108,603	7,640	122	-	1,246	1,315	686	-
Working Capital												
CWC	Cash Working Capital											
	CWC	S	8,503,482	5,413,388	798,144	2,008,543	14,695	-	109,753	91,386	67,573	-
	CWC	SO	-	-	-	-	-	-	-	-	-	-
	CWC	SE	-	-	-	-	-	-	-	-	-	-
			8,503,482	5,413,388	798,144	2,008,543	14,695	-	109,753	91,386	67,573	-
OWC	Other Work. Cap.											
131	Cash	GP	SNP	-	-	-	-	-	-	-	-	-
135	Working Funds	GP	SG	-	-	-	-	-	-	-	-	-
141	Notes Receivable	GP	SO	-	-	-	-	-	-	-	-	-
143	Other A/R	LABOR	SO	10,498,734	4,271,288	800,945	3,765,683	60,294	614,195	648,057	338,272	-
232	A/P	LABOR	S	-	-	-	-	-	-	-	-	-
232	A/P	LABOR	SO	(1,672,721)	(680,527)	(127,611)	(599,971)	(9,606)	(97,857)	(103,252)	(53,895)	-
232	A/P	P	SE	(781,151)	(781,151)	-	-	-	-	-	-	-
232	A/P	P	SG	(868,492)	(868,492)	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	S	-	-	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	SE	(2,332,287)	(2,332,287)	-	-	-	-	-	-	-
230	Asset Retir. Oblig.	P	SE	-	-	-	-	-	-	-	-	-
230	Asset Retir. Oblig.	P	S	-	-	-	-	-	-	-	-	-
254	Decom. Reg Liability	P	SG	-	-	-	-	-	-	-	-	-
254	Reclam. Reg Liability	P	SE	-	-	-	-	-	-	-	-	-
2533	Cholla Reclamation	P	SE	-	-	-	-	-	-	-	-	-
			4,844,083	(391,169)	673,334	3,165,712	50,688	-	516,337	544,805	284,376	-
Total Working Capital			13,347,565	5,022,220	1,471,478	5,174,255	65,382	-	626,090	636,191	351,949	-
Miscellaneous Rate Base												
18221	Unrec Plant & Reg Study Costs	P	S	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-	-
18222	Nuclear Plant - Trojan											
		P	S	-	-	-	-	-	-	-	-	-
		P	TROIP	-	-	-	-	-	-	-	-	-
		P	TROJD	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
1869	Misc Deferred Debits-Trojan											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
TOTAL MISCELLANEOUS RATE BASE			-	-	-	-	-	-	-	-	-	-
<b>TOTAL RATE BASE ADDITIONS</b>			<b>217,391,352</b>	<b>179,934,050</b>	<b>6,379,984</b>	<b>25,466,478</b>	<b>195,008</b>	<b>-</b>	<b>1,908,235</b>	<b>2,429,160</b>	<b>1,078,438</b>	<b>-</b>
235	Customer Service Deposits											
		C_BILLING	S	-	-	-	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
2281	Prov for Property Insuranc	LABOR	S	20,937,606	8,518,223	1,597,323	7,509,895	120,245	1,224,887	1,292,419	674,614	-
2282	Prov for Injuries & Damag	LABOR	SO	-	-	-	-	-	-	-	-	-
2282	Prov for Injuries & Damag	LABOR	S	(12,416,392)	(5,051,465)	(947,243)	(4,453,508)	(71,307)	(726,381)	(766,429)	(400,059)	-
2283	Prov for Pensions and Ben	LABOR	SO	(438,084)	(178,229)	(33,421)	(157,132)	(2,516)	(25,629)	(27,042)	(14,115)	-
2283	Prov for Pensions and Ben	LABOR	S	-	-	-	-	-	-	-	-	-
25335	Pens Oblig	LABOR	SE	(28,858,211)	(11,740,629)	(2,201,584)	(10,350,855)	(165,733)	(1,688,257)	(1,781,336)	(929,818)	-
254	Reg Liabilities - Insurance	LABOR	SO	(3,044,156)	(1,238,480)	(232,238)	(1,091,877)	(17,483)	(178,089)	(187,907)	(98,083)	-
			(23,819,237)	(9,690,581)	(1,817,162)	(8,543,477)	(136,794)	-	(1,393,468)	(1,470,294)	(767,461)	-
22841	Accum Misc Oper Provisions - Other											
		P	S	-	-	-	-	-	-	-	-	-
		P	SG	(61,227)	(61,227)	-	-	-	-	-	-	-
				(61,227)	(61,227)	-	-	-	-	-	-	-
254105	ARO	P	S	-	-	-	-	-	-	-	-	-
230	ARO	P	TROJD	(1,441,094)	(1,441,094)	-	-	-	-	-	-	-
254105	ARO	P	TROJD	-	-	-	-	-	-	-	-	-
254		P	S	(369,192,352)	(369,192,352)	-	-	-	-	-	-	-
				(370,633,446)	(370,633,446)	-	-	-	-	-	-	-
252	Customer Advances for Construction											
		D_SPLIT	S	(2,069,907)	-	-	(1,961,291)	(23,889)	-	(84,727)	-	-
		T	SE	-	-	-	-	-	-	-	-	-
		T	SG	(20,960,626)	-	(20,960,626)	-	-	-	-	-	-
		D_SPLIT	SO	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-
				(23,030,533)	-	(20,960,626)	(1,961,291)	(23,889)	-	(84,727)	-	-
25398	SO2 Emissions	P	SE	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-
25399	Other Deferred Credits											
		D_SPLIT	S	(204,430)	-	-	(193,702)	(2,359)	-	(8,368)	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-
		P	SG	(16,645,479)	(16,645,479)	-	-	-	-	-	-	-
		P	SE	(3,659,474)	(3,659,474)	-	-	-	-	-	-	-
				(20,509,383)	(20,304,954)	-	(193,702)	(2,359)	-	(8,368)	-	-
190	Accumulated Deferred Income Taxes											
		D_SPLIT	S	93,571,742	-	-	88,661,674	1,079,920	-	3,830,148	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-
		LABOR	SO	14,655,014	5,962,223	1,118,026	5,256,456	84,164	857,344	904,613	472,188	-
		P	GPS	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	2,391,934	-	-	-	-	2,391,934	-	-	-
		P	TROJD	333,666	333,666	-	-	-	-	-	-	-
		P	SG	358,454	358,454	-	-	-	-	-	-	-
		P	SE	473,309	473,309	-	-	-	-	-	-	-
		LABOR	SNP	-	-	-	-	-	-	-	-	-
		D_SPLIT	SNPD	409,509	-	-	388,021	4,726	-	16,762	-	-
		P	SG	-	-	-	-	-	-	-	-	-
				112,193,627	7,127,651	1,118,026	94,306,151	1,168,810	3,249,278	4,751,523	472,188	-





				(261,797,228)	-	-	(261,797,228)	-	-	-	-	-	-
108365	Overhead Conductors	D	S	(142,507,594)	-	-	(142,507,594)	-	-	-	-	-	-
				(142,507,594)	-	-	(142,507,594)	-	-	-	-	-	-
108366	Underground Conduit	D	S	(50,993,314)	-	-	(50,993,314)	-	-	-	-	-	-
				(50,993,314)	-	-	(50,993,314)	-	-	-	-	-	-
108367	Underground Conductors	D	S	(101,295,777)	-	-	(101,295,777)	-	-	-	-	-	-
				(101,295,777)	-	-	(101,295,777)	-	-	-	-	-	-
108368	Line Transformers	D	S	(260,127,513)	-	-	(260,127,513)	-	-	-	-	-	-
				(260,127,513)	-	-	(260,127,513)	-	-	-	-	-	-
108369	Services	D	S	(150,368,950)	-	-	(150,368,950)	-	-	-	-	-	-
				(150,368,950)	-	-	(150,368,950)	-	-	-	-	-	-
108370	Meters	C_Meter	S	(23,688,784)	-	-	-	-	-	-	(23,688,784)	-	-
				(23,688,784)	-	-	-	-	-	-	(23,688,784)	-	-
108371	Installations on Customers' Premises	DL	S	(2,168,171)	-	-	-	(2,168,171)	-	-	-	-	-
				(2,168,171)	-	-	-	(2,168,171)	-	-	-	-	-
108372	Leased Property	D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108373	Street Lights	DL	S	(13,088,693)	-	-	-	(13,088,693)	-	-	-	-	-
				(13,088,693)	-	-	-	(13,088,693)	-	-	-	-	-
108D00	Unclassified Dist Plant - Acct 300	D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108DS	Unclassified Dist Sub Plant - Acct 300	D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108DP	Unclassified Dist Sub Plant - Acct 300	D_SPLIT	S	2,061,813	-	-	1,953,622	23,796	-	-	84,396	-	-
				2,061,813	-	-	1,953,622	23,796	-	-	84,396	-	-
<b>TOTAL DISTRIBUTION PLANT DEPR</b>				<b>(1,122,481,268)</b>	-	-	<b>(1,083,643,812)</b>	<b>(15,233,068)</b>	-	-	<b>(23,604,388)</b>	-	-
108GP	General Plant Accumulated Depr	D_SPLIT	S	(108,559,029)	-	-	(102,862,521)	(1,252,889)	-	-	(4,443,618)	-	-
		G-DGP	SG	(186,466)	(118,130)	(68,336)	-	-	-	-	-	-	-
		G-DGU	SG	(508,818)	(322,346)	(186,472)	-	-	-	-	-	-	-
		G-SG	SG	(36,230,166)	(14,908,684)	(21,321,482)	-	-	-	-	-	-	-
		B_Center	CN	(2,141,251)	-	-	-	-	(1,394,909)	-	(746,342)	-	-
		LABOR	SO	(34,259,759)	(13,938,186)	(2,613,666)	(12,288,281)	(196,754)	(2,004,257)	(2,114,758)	(1,103,857)	-	-
		P	SE	(374,616)	(374,616)	-	-	-	-	-	-	-	-
		G-SG	SG	(33,997)	(13,990)	(20,007)	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
				(182,294,103)	(29,675,951)	(24,209,964)	(115,150,802)	(1,449,643)	-	(3,399,166)	(6,558,377)	(1,850,199)	-
108MP	Mining Plant Accumulated Depr.	P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
108MP	Less Centralia Sitis 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			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
<b>TOTAL GENERAL PLANT ACCUM DEPR</b>				<b>(182,294,103)</b>	<b>(29,675,951)</b>	<b>(24,209,964)</b>	<b>(115,150,802)</b>	<b>(1,449,643)</b>	-	<b>(3,399,166)</b>	<b>(6,558,377)</b>	<b>(1,850,199)</b>	-
<b>TOTAL ACCUM DEPR - PLANT IN SERVICE</b>				<b>(3,571,364,011)</b>	<b>(1,740,982,885)</b>	<b>(579,491,671)</b>	<b>(1,198,794,615)</b>	<b>(16,682,711)</b>	-	<b>(3,399,166)</b>	<b>(30,162,765)</b>	<b>(1,850,199)</b>	-
111SP	Accum Prov for Amort-Steam	P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
111GP	Accum Prov for Amort-General	D_SPLIT	S	(5,225,362)	-	-	(4,951,167)	(60,306)	-	-	(213,888)	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(363,384)	(147,839)	(27,722)	(130,339)	(2,087)	(21,259)	(22,431)	(11,708)	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				(5,588,746)	(147,839)	(27,722)	(5,081,506)	(62,393)	-	(21,259)	(236,319)	(11,708)	-
111HP	Accum Prov for Amort-Hydro	P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(940,299)	(940,299)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-

			(940,299)	(940,299)	-	-	-	-	-	-	-
111IP	Accum Prov for Amort-Intangible Plant										
	D_SPLIT	S	(140,175)	-	-	(132,819)	(1,618)	-	-	(5,738)	-
	LABOR	SG	-	-	-	-	-	-	-	-	-
	LABOR	SG	(103,514)	(42,114)	(7,897)	(37,129)	(594)	-	(6,056)	(6,390)	(3,335)
	P	SE	21,235	21,235	-	-	-	-	-	-	-
	LABOR	SG	(30,133,638)	(12,259,522)	(2,298,886)	(10,808,325)	(173,057)	-	(1,762,871)	(1,860,065)	(970,913)
	I-SG	SG	(30,888,669)	(20,283,571)	(10,579,811)	(24,482)	-	-	-	(805)	-
	I-SG	SG	(1,554,304)	(1,020,660)	(532,371)	(1,232)	-	-	-	(40)	-
	CSS_SYS	CN	(56,627,623)	-	-	-	-	-	(25,104,913)	(13,213,112)	(18,309,598)
	P	SG	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-
	LABOR	SO	(92,153,375)	(37,491,533)	(7,030,351)	(33,053,547)	(529,236)	-	(5,391,137)	(5,688,368)	(2,969,202)
			(211,580,064)	(71,076,165)	(20,449,317)	(44,057,534)	(704,506)	-	(32,264,977)	(20,774,517)	(22,253,048)
111IP	Less Non-Utility Plant										
		NUTIL	OTH	-	-	-	-	-	-	-	-
				(211,580,064)	(71,076,165)	(20,449,317)	(44,057,534)	(704,506)	(32,264,977)	(20,774,517)	(22,253,048)
111390	Accum Amtr - Capital Lease										
	LABOR	S	-	-	-	-	-	-	-	-	-
	P	SG	-	-	-	-	-	-	-	-	-
	LABOR	SO	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-
	Remove Capital Lease Amtr										
			-	-	-	-	-	-	-	-	-
<b>TOTAL ACCUM PROV FOR AMORTIZATION</b>			<b>(218,109,109)</b>	<b>(72,164,303)</b>	<b>(20,477,039)</b>	<b>(49,139,039)</b>	<b>(766,899)</b>	<b>-</b>	<b>(32,286,235)</b>	<b>(21,010,836)</b>	<b>(22,264,757)</b>

Docket No. UE 399  
Exhibit PAC/1104  
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Robert M. Meredith  
Functional Factors**

**March 2022**

Functional Factors											
Function	Description	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C.Billing	C.Metering	C.Service	DSM	Total
<b>Internal Factors</b>											
CWC	Cash Working Capital	63.6608%	9.3861%	23.6202%	0.1728%	0.0000%	1.2907%	1.0747%	0.7946%	0.0000%	100.0000%
D_SPLIT	Distribution Split between Functions	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	4.0933%	0.0000%	0.0000%	100.0000%
GP	Gross Plant	42.6142%	24.0096%	30.4331%	0.3752%	0.0000%	0.5596%	1.6415%	0.3668%	0.0000%	100.0000%
IBT	Income Before Taxes	272.5050%	-40.5134%	-131.9652%	-3.5471%	0.0000%	6.4893%	-7.7107%	0.0000%	0.0000%	100.0000%
NP	Net Plant	38.6979%	30.1295%	28.5632%	0.3114%	0.0000%	0.2736%	1.8593%	0.1651%	0.0000%	100.0000%
PT	Production / Transmission	62.6163%	37.3837%								100.0000%
PTD	Prod, Trans, Dist Plant	43.3975%	25.9096%	30.6929%							100.0000%
REVREQ	Revenue Requirement	58.3615%	13.6152%	24.7771%	0.1955%	0.0000%	1.0811%	1.2967%	0.6729%	0.0000%	100.0000%
T_SPLIT	Transmission Split	2.0469%	97.9531%								100.0000%
TD	Transmission / Distribution		45.7746%	54.2254%							100.0000%
<b>External Factors</b>											
ACCMGIT	Deferred Income Tax - Balance	50.0593%	25.1772%	24.6386%	0.0000%	0.0000%	0.0624%	0.0626%	0.0000%	0.0000%	100.0000%
ANC	Ancillary Function	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
B_CENTER	Business Centers	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	65.1446%	0.0000%	34.8554%	0.0000%	100.0000%
BOOKDEPR	Book Depreciation	66.9276%	13.4979%	18.6061%	0.2634%	0.0000%	0.0934%	0.6115%	0.0000%	0.0000%	100.0000%
C BILLING	Customer Billing	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%
C_METER	Customer Metering	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	100.0000%
C_SERVICE	Customer Other	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	100.0000%
CSS_SYS	CSS System	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	44.3333%	23.3333%	32.3333%	0.0000%	100.0000%
CUST	Customer	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	44.3333%	23.3333%	32.3333%	0.0000%	100.0000%
CUST901	Supervision	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	44.8021%	48.4141%	6.7838%	0.0000%	100.0000%
CUST903	Cust. Records & Coll. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	67.0500%	5.7551%	27.1949%	0.0000%	100.0000%
CUST905	Misc. Customer Acct. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	100.0000%
D	Distribution Only	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DL	Distribution Only-LGT	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DDS2	Deferred Debits - Situs	77.3972%	3.1278%	16.0812%	0.1232%	0.0000%	1.2551%	1.3243%	0.6912%	0.0000%	100.0000%
DDS6	Deferred Debits - Situs	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DDS02	Deferred Debits - System Overhead	39.6393%	7.7128%	37.9806%	0.5325%	0.0000%	5.4242%	5.7232%	2.9874%	0.0000%	100.0000%
DDS06	Deferred Debits - System Overhead	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DEFSG	Deferred Debit - System Generation	91.6259%	8.3741%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DSM	Demand Side Management	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DPW	Distribution Poles & Wires	0.0000%	0.0000%	96.8179%	0.0000%	0.0000%	0.0000%	3.1821%	0.0000%	0.0000%	100.0000%
ESD	Environmental Services Department	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
FERC	FERC Fees	40.2029%	59.7971%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G	General Plant	20.3997%	36.1935%	40.7338%	0.0000%	0.0000%	1.3343%	1.3388%	0.0000%	0.0000%	100.0000%
G-DGP	General Plant - DGP Factor	63.3519%	36.6481%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G-DGU	General Plant - DGU Factor	63.3519%	36.6481%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G-SG	General Plant - SG Factor	41.1499%	58.8501%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G-SITUS	General Plant - SITUS Factor	0.0000%	31.1670%	66.6426%	0.0000%	0.0000%	0.0000%	2.1903%	0.0000%	0.0000%	100.0000%
I	Intangible Plant	48.5579%	17.0250%	12.1643%	0.0000%	0.0000%	7.8659%	8.3673%	6.0196%	0.0000%	100.0000%
I-DGP	Intangible Plant - DGP Factor	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-DGU	Intangible Plant - DGU Factor	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-SG	Intangible Plant - SG Factor	65.6667%	34.2514%	0.0793%	0.0000%	0.0000%	0.0000%	0.0026%	0.0000%	0.0000%	100.0000%
I-SITUS	Intangible Plant - SITUS Factor	0.0000%	2.4335%	94.4618%	0.0000%	0.0000%	0.0000%	3.1047%	0.0000%	0.0000%	100.0000%
LABOR	Direct Labor Expense	40.6838%	7.6290%	35.8680%	0.5743%	0.0000%	5.8502%	6.1727%	3.2220%	0.0000%	100.0000%
MSS	Materials & Supplies	81.6861%	1.4794%	16.2988%	0.0000%	0.0000%	0.0000%	0.5357%	0.0000%	0.0000%	100.0000%
NONE	Not Functionalized	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
NUTIL	Non-Utility	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
OTHDGP	Other Revenues - DGP Factor	22.9341%	77.0630%	0.0029%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHDGU	Other Revenues - DGU Factor	22.9341%	77.0630%	0.0029%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSE	Other Revenues - SE Factor	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSG	Other Revenues - SG Factor	22.9341%	77.0630%	0.0029%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSGR	Other Revenues - Rolled-In SG Factor	22.9341%	77.0630%	0.0029%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSITUS	Other Revenues - SITUS	0.3440%	89.6679%	9.9881%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSO	Other Revenues - SO Factor	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
P	Production	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMA	Schedule M Additions	58.6408%	14.4458%	24.6911%	0.0213%	0.0000%	0.8772%	1.0855%	0.2381%	0.0000%	100.0000%
SCHMAF	Schedule M Additions - Flow Through	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMAP	Schedule M Additions - Permanent	74.5155%	3.2777%	15.4102%	0.2467%	0.0000%	2.5135%	2.6520%	1.3843%	0.0000%	100.0000%
SCHMAP-SO	Schedule M Additions - Permanent-SO	75.5976%	3.1385%	14.7559%	0.2363%	0.0000%	2.4067%	2.5394%	1.3255%	0.0000%	100.0000%
SCHMAT	Schedule M Additions - Temporary	58.5956%	14.4776%	24.7176%	0.0207%	0.0000%	0.8726%	1.0811%	0.2349%	0.0000%	100.0000%
SCHMAT-SG	Schedule M Additions - Temporary-SG	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMAT-SE	Schedule M Additions - Temporary-SE	99.8835%	0.0150%	0.0704%	0.0011%	0.0000%	0.0115%	0.0121%	0.0063%	0.0000%	100.0000%
SCHMAT-SITU	Schedule M Additions - Temporary-SITUS	100.5549%	-0.4620%	-0.1999%	0.0045%	0.0000%	0.0458%	0.0314%	0.0252%	0.0000%	100.0000%
SCHMAT-SNP	Schedule M Additions - Temporary-SNP	46.2446%	26.7584%	26.1334%	0.0000%	0.0000%	0.0022%	0.8600%	0.0015%	0.0000%	100.0000%
SCHMAT-SO	Schedule M Additions - Temporary-SO	40.5835%	7.2842%	36.0435%	0.5847%	0.0000%	5.9556%	6.2685%	3.2801%	0.0000%	100.0000%
SCHMD	Schedule M Deductions	63.5198%	20.6824%	16.3163%	-0.0659%	0.0000%	-0.0089%	-0.2770%	-0.1667%	0.0000%	100.0000%
SCHMDF	Schedule M Deductions - Flow Through	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMDP	Schedule M Deductions - Permanent	99.0933%	0.4514%	0.4408%	0.0000%	0.0000%	0.0000%	0.0145%	0.0000%	0.0000%	100.0000%
SCHMDP-SO	Schedule M Deductions - Permanent- SO	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
SCHMDT	Schedule M Deductions - Temporary	63.3764%	20.7640%	16.3802%	-0.0661%	0.0000%	-0.0089%	-0.2782%	-0.1673%	0.0000%	100.0000%
SCHMDT-GPS	Schedule M Deductions - Temporary-GPS	46.2535%	26.7567%	26.1309%	0.0000%	0.0000%	0.0000%	0.8588%	0.0000%	0.0000%	100.0000%
SCHMDT-SG	Schedule M Deductions - Temporary-SG	99.9797%	0.0203%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMDT-SITU	Schedule M Deductions - Temporary-SITUS	109.3757%	-2.4106%	-5.9473%	-0.0339%	0.0000%	-0.3611%	-0.4219%	-0.2009%	0.0000%	100.0000%
SCHMDT-SNP	Schedule M Deductions - Temporary-SNP	46.2535%	26.7567%	26.1309%	0.0000%	0.0000%	0.0000%	0.8588%	0.0000%	0.0000%	100.0000%
SCHMDT-SO	Schedule M Deductions - Temporary-SO	35.4236%	-22.5098%	43.5913%	1.6291%	0.0000%	16.5684%	16.1757%	9.1218%	0.0000%	100.0000%
STEP_UP	Step-up Transformers	7.0314%	92.9686%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
T	Transmission	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
TAXDEPR	Tax Depreciation	62.2078%	18.8524%	17.4885%	0.0200%	0.0000%	0.5807%	0.4711%	0.3794%	0.0000%	100.0000%

Docket No. UE 399  
Exhibit PAC/1105  
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Robert M. Meredith  
Ancillary Services Revenue Requirement**

**March 2022**

PACIFICORP  
STATE OF OREGON  
Combined GRC and TAM  
Ancillary Services Revenue  
12 Months Ended December 31, 2023 Forecast

Oregon Annual Ancillary Service Revenue \$23,847,685

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)

Load <sup>1</sup>			
Line	Description	Calculation	Value
1	Sum of 12 Oregon Monthly Peaks (MW)		27,220
2	Total Oregon Retail Load (MWh)		15,310,450
4	Schedule 3 Load Rate (\$/MW-month)		\$115
5	Schedule 3 Revenue	1*4	\$3,130,277
7	Schedule 5 Rate (\$/MWh)		\$0.168
8	Schedule 5 Revenue	2*7	\$2,572,156
10	Schedule 6 Rate (\$/MWh)		\$0.168
11	Schedule 6 Revenue	2*10	\$2,572,156
14	Total Oregon Load Revenue	5+8+11	\$8,274,588

Generation			
Line	Description	Calculation	Value
1	Sum of 12 Total System VER Generator Nameplate Capacities (MW) <sup>2</sup>		67,991
2	Sum of 12 Total System Non-VER Generator Nameplate Capacities (MW)		12,114
3	Total System Generation MWh at input		62,280,620
4			
5	Schedule 3A VER Rate (\$/MW-month)		\$524
6	Schedule 3A VER Revenue	1*5	\$35,634,858
7			
8	Schedule 3A Non-VER Rate (\$/MW-month)		\$262
9	Schedule 3A Non-VER Revenue	2*8	\$3,173,767
10			
11	Schedule 5 Rate (\$/MWh)		\$0.168
12	Schedule 5 Revenue	3*11	\$10,463,144
13			
14	Schedule 6 Rate (\$/MWh)		\$0.168
15	Schedule 6 Revenue	3*14	\$10,463,144
16			
17			
18	Total Generation Revenue	6+9+12+15	\$59,734,914
19			
20	Oregon JAM SG Factor		26%
21	Oregon-allocated Total Generation Revenue	18*20	\$15,573,096

<sup>1</sup>Load is Oregon's Contributions to Monthly Firm System Retail Load at input

<sup>2</sup>All VER Generation is assumed to be Uncommitted (see OATT Schedule 3A requirements for Committed and Uncommitted)

Docket No. UE 399  
Exhibit PAC/1106  
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Robert M. Meredith  
Oregon Marginal Cost of Service Study Summary**

**March 2022**



PACIFICORP  
STATE OF OREGON  
Oregon Marginal Cost Study  
20 Year Marginal Cost By Load Class  
12 Months Ended December 31, 2023 Forecast  
(Dollars in 000s)

Line	Class / Function	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Total	Residential (sec)	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48				Irrg - Sch 41 (sec)	Lighting Schs 15, 51, 53, 54 (sec)	
			0-15 kW (sec)	15+ kW (sec)	Primary (pri)	0-50 kW (sec)	51-100 kW (sec)	100 + kW (sec)	Primary (pri)	0-300 kW (sec)	300+ kW (sec)	Primary (pri)	1 - 4 MW (sec)	1 - 4 MW (pri)	> 4 MW (sec)	> 4 MW (pri)	Tm (trn)			
1	<u>Demand Related Marginal Cost</u>																			
2	Generation	\$220,002	\$107,503	\$8,554	\$9,332	\$44	\$6,793	\$10,074	\$12,856	\$344	\$2,783	\$13,848	\$1,425	\$6,976	\$6,491	\$474	\$11,655	\$17,333	\$3,516	\$0
3	Transmission	\$10,329	\$5,047	\$402	\$438	\$2	\$319	\$473	\$604	\$16	\$131	\$650	\$67	\$328	\$305	\$22	\$547	\$814	\$165	\$0
4	Distribution																			
5	Poles	\$43,954	\$23,495	\$2,370	\$2,643	\$9	\$1,252	\$1,841	\$2,351	\$56	\$377	\$1,857	\$180	\$2,043	\$1,894	\$4	\$123	\$0	\$3,383	\$77
6	Conductor	\$64,852	\$36,118	\$3,168	\$3,533	\$12	\$1,905	\$2,800	\$3,577	\$85	\$653	\$3,215	\$312	\$2,658	\$2,464	\$9	\$238	\$0	\$4,004	\$103
7	Substations	\$44,587	\$25,258	\$1,670	\$1,863	\$6	\$1,331	\$1,957	\$2,500	\$59	\$554	\$2,726	\$264	\$1,406	\$1,304	\$96	\$2,363	\$0	\$1,230	\$0
8	Transformers	\$9,372	\$5,495	\$675	\$419	\$0	\$434	\$716	\$562	\$0	\$102	\$385	\$0	\$192	\$0	\$13	\$0	\$0	\$341	\$37
9	Total Demand	\$393,096	\$202,915	\$16,837	\$18,228	\$74	\$12,034	\$17,862	\$22,449	\$559	\$4,600	\$22,681	\$2,248	\$13,602	\$12,458	\$619	\$14,926	\$18,147	\$12,640	\$218
10																				
11																				
12	<u>Energy Related Marginal Cost</u>																			
13	Generation	\$526,179	\$214,837	\$20,792	\$22,439	\$125	\$16,672	\$25,372	\$33,020	\$894	\$7,293	\$37,824	\$3,696	\$19,341	\$18,778	\$1,476	\$36,197	\$56,490	\$10,051	\$883
14	Transmission	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
15	Total Energy	\$526,179	\$214,837	\$20,792	\$22,439	\$125	\$16,672	\$25,372	\$33,020	\$894	\$7,293	\$37,824	\$3,696	\$19,341	\$18,778	\$1,476	\$36,197	\$56,490	\$10,051	\$883
16																				
17	<u>Customer Related Marginal Cost</u>																			
18	Poles	\$55,496	\$42,111	\$8,672	\$1,790	\$14	\$382	\$282	\$160	\$5	\$12	\$29	\$3	\$12	\$8	\$0	\$0	\$0	\$2,015	\$0
19	Conductor	\$27,553	\$20,908	\$4,305	\$889	\$7	\$190	\$140	\$79	\$3	\$6	\$14	\$1	\$6	\$4	\$0	\$0	\$0	\$1,001	\$0
20	Transformers	\$76,429	\$45,720	\$12,013	\$3,293	\$0	\$3,414	\$2,868	\$1,754	\$0	\$211	\$527	\$0	\$91	\$0	\$1	\$0	\$0	\$6,535	\$0
21	Lighting	\$6,326	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$6,326
22	Service Drops	\$53,903	\$40,536	\$7,153	\$2,859	\$0	\$989	\$763	\$836	\$0	\$88	\$424	\$0	\$252	\$0	\$3	\$0	\$0	\$0	\$0
23	Meters	\$16,150	\$12,418	\$1,724	\$409	\$134	\$154	\$122	\$357	\$80	\$38	\$95	\$62	\$20	\$71	\$0	\$33	\$159	\$273	\$3
24	Meter Reading	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
25	Billing & Collections	\$16,770	\$13,430	\$2,119	\$437	\$3	\$170	\$125	\$71	\$2	\$7	\$19	\$2	\$27	\$18	\$0	\$8	\$2	\$132	\$196
26	Uncollectables	\$5,914	\$5,155	\$174	\$36	\$0	\$121	\$89	\$50	\$2	\$32	\$79	\$8	\$64	\$43	\$1	\$20	\$6	\$36	\$0
27	Customer Service / Other	\$5,964	\$4,955	\$642	\$132	\$1	\$49	\$36	\$21	\$1	\$3	\$8	\$1	\$4	\$3	\$0	\$1	\$0	\$41	\$66
28	Total Customer (Commitment & Billing)	\$264,503	\$185,235	\$36,801	\$9,846	\$160	\$5,468	\$4,426	\$3,326	\$93	\$397	\$1,195	\$77	\$475	\$145	\$5	\$61	\$167	\$10,034	\$6,590
29																				
30																				
31	<u>Total Revenue @ Full MC</u>																			
32	Generation	\$746,181	\$322,340	\$29,346	\$31,771	\$169	\$23,465	\$35,447	\$45,875	\$1,238	\$10,076	\$51,673	\$5,121	\$26,317	\$25,269	\$1,951	\$47,852	\$73,823	\$13,567	\$883
33	Transmission	\$10,329	\$5,047	\$402	\$438	\$2	\$319	\$473	\$604	\$16	\$131	\$650	\$67	\$328	\$305	\$22	\$547	\$814	\$165	\$0
34	Distribution	\$376,144	\$239,641	\$40,026	\$17,289	\$49	\$9,897	\$11,368	\$11,817	\$207	\$2,002	\$9,178	\$760	\$6,659	\$5,673	\$126	\$2,724	\$0	\$18,509	\$218
35	Distribution-Lighting	\$6,326	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$6,326
36	Customer - Billing	\$16,770	\$13,430	\$2,119	\$437	\$3	\$170	\$125	\$71	\$2	\$7	\$19	\$2	\$27	\$18	\$0	\$8	\$2	\$132	\$196
37	Customer - Metering	\$16,150	\$12,418	\$1,724	\$409	\$134	\$154	\$122	\$357	\$80	\$38	\$95	\$62	\$20	\$71	\$0	\$33	\$159	\$273	\$3
38	Customer - Other	\$5,964	\$4,955	\$642	\$132	\$1	\$49	\$36	\$21	\$1	\$3	\$8	\$1	\$4	\$3	\$0	\$1	\$0	\$41	\$66
39	Revenue (less Uncollectables)	\$1,177,864	\$597,832	\$74,257	\$50,476	\$358	\$34,053	\$47,571	\$58,745	\$1,545	\$12,258	\$61,622	\$6,012	\$33,354	\$31,338	\$2,100	\$51,165	\$74,798	\$32,688	\$7,691
40																				
41	Customer - Uncollectables	\$5,914	\$5,155	\$174	\$36	\$0	\$121	\$89	\$50	\$2	\$32	\$79	\$8	\$64	\$43	\$1	\$20	\$6	\$36	\$0
42	Total Revenue	\$1,183,778	\$602,987	\$74,431	\$50,512	\$359	\$34,174	\$47,660	\$58,795	\$1,546	\$12,289	\$61,701	\$6,020	\$33,418	\$31,381	\$2,100	\$51,185	\$74,804	\$32,724	\$7,691

Docket No. UE 399  
Exhibit PAC/1107  
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Robert M. Meredith  
Unbundled Revenue Requirement Allocation**

**March 2022**

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

Line	Description	Total	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	Lighting Detail		
			Residential	General Service		General Service		General Service		Large Power Service			Irrigation	Lighting	Schs 15 & 51	Sch 53	Sch 54
			(sec)	Sch 23	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	Sch 41	Schs 15, 51, 53, and 54	(sec)
1	Total Operating Revenues	\$1,238,175	\$597,063	\$124,106	\$332	\$161,664	\$2,068	\$86,965	\$7,232	\$40,979	\$96,027	\$87,395	\$29,194	\$5,151	\$4,413	\$657	\$82
2	MWh	13,886,900	5,633,856	1,133,687	3,324	1,968,466	23,804	1,183,142	98,439	545,911	1,464,317	1,545,236	263,565	23,152	10,559	11,452	1,141
3																	
4	Functionalized 20 Year Full Marginal Costs - Class S																
5	Generation	\$746,181	\$322,340	\$61,117	\$169	\$104,787	\$1,238	\$61,749	\$5,121	\$28,268	\$73,121	\$73,823	\$13,567	\$883	\$403	\$437	\$44
6	Transmission	\$10,329	\$5,047	\$840	\$2	\$1,396	\$16	\$781	\$67	\$350	\$852	\$814	\$165	\$0	\$0	\$0	\$0
7	Distribution	\$376,144	\$239,641	\$57,315	\$49	\$33,082	\$207	\$11,180	\$760	\$6,785	\$8,397	\$0	\$18,509	\$218	\$203	\$5	\$9
8	Distribution-Lighting	\$6,326	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$6,326	\$6,326	\$0	\$0
9	Customer - Billing	\$16,770	\$13,430	\$2,556	\$3	\$366	\$2	\$26	\$2	\$27	\$26	\$2	\$132	\$196	\$185	\$8	\$3
10	Customer - Metering	\$16,150	\$12,418	\$2,132	\$134	\$632	\$80	\$133	\$62	\$20	\$104	\$159	\$273	\$3	\$0	\$0	\$3
11	Customer - Other	\$5,964	\$4,955	\$774	\$1	\$106	\$1	\$11	\$1	\$4	\$4	\$0	\$41	\$66	\$62	\$3	\$1
12	Total	\$1,177,864	\$597,832	\$124,734	\$358	\$140,369	\$1,545	\$73,880	\$6,012	\$35,454	\$82,503	\$74,798	\$32,688	\$7,691	\$7,178	\$453	\$59
13																	
14	Functional Revenue Requirement Allocation Factors																
15	Functionalized 20 Year Full Marginal Costs - Class % of Total																
16	Generation	100.00%	43.20%	8.19%	0.02%	14.04%	0.17%	8.28%	0.69%	3.79%	9.80%	9.89%	1.82%	0.12%	0.05%	0.06%	0.01%
17	Transmission	100.00%	48.86%	8.13%	0.02%	13.51%	0.16%	7.56%	0.65%	3.39%	8.25%	7.88%	1.60%	0.00%	0.00%	0.00%	0.00%
18	Distribution	100.00%	63.71%	15.24%	0.01%	8.80%	0.06%	2.97%	0.20%	1.80%	2.23%	0.00%	4.92%	0.06%	0.05%	0.00%	0.00%
19	Distribution-Lighting	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	100.00%	0.00%	0.00%
20	Ancillary Service	100.00%	43.20%	8.19%	0.02%	14.04%	0.17%	8.28%	0.69%	3.79%	9.80%	9.89%	1.82%	0.12%	0.05%	0.06%	0.01%
21	Customer - Billing	100.00%	80.09%	15.24%	0.02%	2.18%	0.01%	0.16%	0.01%	0.16%	0.15%	0.01%	0.79%	1.17%	1.10%	0.05%	0.02%
22	Customer - Metering	100.00%	76.89%	13.20%	0.83%	3.92%	0.50%	0.82%	0.38%	0.12%	0.64%	0.99%	1.69%	0.02%	0.00%	0.00%	0.02%
23	Customer - Other	100.00%	83.09%	12.98%	0.02%	1.78%	0.01%	0.18%	0.01%	0.07%	0.07%	0.01%	0.69%	1.10%	1.04%	0.05%	0.02%
24	Embedded DSM - (MWh)	100.00%	40.57%	8.16%	0.02%	14.17%	0.17%	8.52%	0.71%	3.93%	10.54%	11.13%	1.90%	0.17%	0.08%	0.08%	0.01%
25	Regulatory & Franchise - (Total Operating Revenues)	100.00%	48.22%	10.02%	0.03%	13.06%	0.17%	7.02%	0.58%	3.31%	7.76%	7.06%	2.36%	0.42%	0.36%	0.05%	0.01%
26																	
27																	
28	Functionalized Class Revenue Requirement - (Target)																
29	Generation	\$744,404	\$321,572	\$60,971	\$168	\$104,538	\$1,235	\$61,602	\$5,108	\$28,200	\$72,947	\$73,647	\$13,535	\$881	\$402	\$436	\$43
30	Transmission	\$179,693	\$87,806	\$14,609	\$36	\$24,277	\$281	\$13,585	\$1,164	\$6,085	\$14,821	\$14,157	\$2,872	\$0	\$0	\$0	\$0
31	Distribution	\$64,324	\$232,110	\$55,514	\$48	\$32,043	\$201	\$10,829	\$736	\$6,572	\$8,133	\$0	\$17,928	\$211	\$196	\$5	\$9
32	Distribution-Lighting	\$3,032	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$3,032	\$3,032	\$0	\$0
33	Distribution Total	\$67,356	\$232,110	\$55,514	\$48	\$32,043	\$201	\$10,829	\$736	\$6,572	\$8,133	\$0	\$17,928	\$3,243	\$3,229	\$5	\$9
34	Ancillary Services	\$23,675	\$10,227	\$1,939	\$5	\$3,325	\$39	\$1,959	\$162	\$897	\$2,320	\$2,342	\$430	\$28	\$13	\$14	\$1
35	Customer - Billing	\$15,079	\$12,076	\$2,298	\$3	\$329	\$2	\$24	\$2	\$24	\$23	\$2	\$119	\$177	\$167	\$8	\$2
36	Customer - Metering	\$21,031	\$16,171	\$2,777	\$174	\$824	\$105	\$173	\$80	\$26	\$135	\$207	\$356	\$3	\$0	\$0	\$3
37	Customer - Other	\$9,224	\$7,664	\$1,197	\$2	\$164	\$1	\$17	\$1	\$6	\$6	\$1	\$63	\$102	\$96	\$4	\$1
38	Embedded DSM - (MWh)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
39	Franchise Fees	\$32,642	\$15,740	\$3,272	\$9	\$4,262	\$55	\$2,293	\$191	\$1,080	\$2,532	\$2,304	\$770	\$136	\$116	\$17	\$2
40	Total	\$1,393,104	\$703,367	\$142,577	\$445	\$169,761	\$1,918	\$90,480	\$7,445	\$42,891	\$100,917	\$92,661	\$36,073	\$4,569	\$4,022	\$484	\$63
41																	
42	Ratio of Operating Revn to Revenue Requirement-(Target)	88.88%	84.89%	87.05%	74.61%	95.23%	107.83%	96.12%	97.13%	95.54%	95.15%	94.32%	80.93%	112.73%	109.71%	135.70%	129.01%
43	(Line 1 / Line 40)																
44																	
45	Increase or (Decrease)	\$154,929	\$106,304	\$18,470	\$113	\$8,097	(\$150)	\$3,515	\$213	\$1,913	\$4,890	\$5,266	\$6,879	(\$582)	(\$391)	(\$173)	(\$18)
46	(Line 40 - Line 1)																
47																	
48																	
49	Percent Increase (Decrease)	12.51%	17.80%	14.88%	34.03%	5.01%	-7.26%	4.04%	2.95%	4.67%	5.09%	6.03%	23.56%	-11.29%	-8.85%	-26.31%	-22.49%
50	(Line 45 / Line 1)																

PACIFICORP  
STATE OF OREGON  
Combined GRC and TAM  
Oregon Marginal Cost Study  
December 31, 2023 Functionalized Revenue - Earned  
(\$ 000)

Line No.	Description	A Production	B Transmission	C Distribution	D Dist-Lighting	E Ancillary	F C Billing	G C Metering	I C Other	J Franchise Fees	K Total
1	Earned Functional Revenue Requirement	\$698,716	\$133,281	\$319,434	\$2,548	\$23,848	\$14,720	\$18,059	\$9,077	\$29,219	\$1,248,901
2											
3	Percent of Total	55.95%	10.67%	25.58%	0.20%	1.91%	1.18%	1.45%	0.73%	2.34%	100.00%
4											
5	Revenue From Classes Included in MC Study	\$692,715	\$132,136	\$316,690	\$2,526	\$23,643	\$14,594	\$17,904	\$8,999	\$28,968	\$1,238,175
6											
7	Other Revenues										
8	Schedule 4 - Employee Discount										(\$341)
9	Partial Requirements - Sch. 47 pri										\$1,607
10	Partial Requirements - Sch. 47 trn										\$2,367
11	Sch 848										\$1,805
12	Oregon Direct Access Opt Out Amortization										\$1,767
13	AGA										\$3,521
14	Total Oregon Situs Revenue										\$1,248,901

PACIFICORP  
STATE OF OREGON  
Combined GRC and TAM  
Oregon Marginal Cost Study  
December 31, 2023 Functionalized Revenue - Target  
(\$ 000)

Line No.	Description	A Production	B Transmission	C Distribution	D Dist-Lighting	E Ancillary	F C Billing	G C Metering	I C Other	J Franchise Fees	K Total	
1	Target Functional Revenue Requirement	\$749,838	\$181,005	\$366,984	\$3,055	\$23,848	\$15,189	\$21,184	\$9,292	\$32,880	\$1,403,274	
2												
3	Percent of Total	53.43%	12.90%	26.15%	0.22%	1.70%	1.08%	1.51%	0.66%	2.34%	100.00%	
4												
5	Revenue From Classes Included in MC Study	\$744,404	\$179,693	\$364,324	\$3,032	\$23,675	\$15,079	\$21,031	\$9,224	\$32,642	\$1,393,104	Increase \$154,929
6												
7	Other Revenues											\$154,373
8	Schedule 4 - Employee Discount										(\$399)	(\$59)
9	Partial Requirements - Sch. 47 pri										\$1,623	\$16
10	Partial Requirements - Sch. 47 trn										\$2,286	(\$81)
11	Sch 848										\$1,374	(\$432)
12	Oregon Direct Access Opt Out Amortization										\$1,767	\$0
13	AGA										\$3,521	(\$0)
14	Total Oregon Situs Revenue										\$1,403,274	

PACIFICORP  
 State of Oregon  
 December 31, 2023 Unbundled Revenue Requirement Allocation by Load Class  
 FERC Transmission Revenue (\$ 000)

Line	Description	Total	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			Residential (sec)	General Service Schedule 23 (sec)	General Service Schedule 23 (pri)	General Service Schedule 28 (sec)	General Service Schedule 28 (pri)	General Service Schedule 30 (sec)	General Service Schedule 30 (pri)	Large Power Service Schedule 48 (sec)	Large Power Service Schedule 48 (pri)	Large Power Service Schedule 48 (tm)	Schedule 41 Irrigation	Lighting (sec)
1	Total Transmission Revenue Requirement	\$179,693	\$87,806	\$14,609	\$36	\$24,277	\$281	\$13,585	\$1,164	\$6,085	\$14,821	\$14,157	\$2,872	\$0
2														
3	FERC Transmission													
4	Peak MW @ Input	2,358	1,152	192	0	319	4	178	15	80	195	186	38	0
5	% of Total	100.00%	48.86%	8.13%	0.02%	13.51%	0.16%	7.56%	0.65%	3.39%	8.25%	7.88%	1.60%	0.00%
6	FERC Transmission Revenues (\$ 000)	\$84,946	\$41,508	\$6,906	\$17	\$11,477	\$133	\$6,422	\$550	\$2,877	\$7,006	\$6,693	\$1,358	\$0
7														
8	Other Transmission Revenue Requirement	\$94,747	\$46,297	\$7,703	\$19	\$12,801	\$148	\$7,163	\$614	\$3,209	\$7,815	\$7,465	\$1,514	\$0

OR CP (MW)

Jan	2,655
Feb	2,484
Mar	2,379
Apr	2,196
May	1,917
Jun	2,051
Jul	2,409
Aug	2,474
Sep	2,161
Oct	1,901
Nov	2,196
Dec	2,398

Annual Average 2,268

Network service rate (\$/MW-year) <sup>1</sup>	\$37,449
FERC Transmission Revenues	\$84,946,194

<sup>1</sup>From 2021 Transmission Formula Rate Annual Update p.14

Docket No. UE 399  
Exhibit PAC/1108  
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Robert M. Meredith  
Oregon Marginal Cost of Service Study**

**March 2022**

## **PacifiCorp**

### **Marginal Cost Study & Circuit Model 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 2023 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 2023.

One, ten and twenty-year marginal costs in mills/kilowatt-hour (kWh) are shown on "Summary of Marginal Costs Demand & Energy in Mills/kWh" (Sheet 'Table 1'). Marginal commitment costs and billing expenses are shown on "Summary of Marginal Costs Commitment and Billing in \$ / Customer / 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 is consistent with the analysis done to prepare the Company's avoided costs filings. Marginal generation costs are based on the Company's most recent avoided cost calculations. The analysis recognizes that baseload generation produces the dual products of capacity and energy. The new resource costs are based on the fixed and variable cost of a Combined Cycle Combustion Turbine (CCCT), which operates as a baseload unit. The cost of the CCCT is split into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT) defines the fixed costs of the CCCT that are assigned to capacity. CCCT fixed costs which are in excess of SCCT fixed costs are assigned to energy. Total energy and capacity costs are present valued, summed, and an annual charge is applied to the total. The marginal generation cost calculation is shown in the



cost of service study on sheet "Summary of Marginal Generation Costs in Nominal Dollars" (Sheet 'Table 4').

### **MARGINAL TRANSMISSION COSTS**

The calculation of transmission costs are based on a five-year (2020-2024) 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 2023 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 "Marginal Transmission Investment and O&M Expenses" (Sheet 'Transm1'). A summarized version of this page is "Marginal Cost of Transmission Investment and Associated Expenses" (Sheet 'Table 5').

### **MARGINAL DISTRIBUTION COSTS**

Distribution costs are classified into three components: Demand-related, shown in dollars per kW/year, commitment-related, shown in dollars per customer/year, and billing-related, shown in dollars per customer/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 "Marginal Distribution & Billing Costs" (Sheet 'Table 6').

Marginal 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 are shown on page "Calculation of Escalation Factors for Transformers" (Sheet 'XFMR3'). Transformer demand costs are shown on page "Transformer Demand Costs" (Sheet 'XFMR2') and commitment costs are shown on page "Transformer Commitment Costs" (Sheet 'XFMR1').

Marginal costs of distribution poles and wires are calculated using the Company's Distribution Circuit Model (Sheets 'PC3' through 'PC14'). 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.

Marginal poles and wire costs are shown on page "Hypothetical Circuit Study Results Annual Demand and Commitment Costs" (Sheet 'PC1').

Marginal substation costs are determined using the per kW cost of budgeted and forecasted substation additions for the five year period 2020 - 2024. 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. The distribution peak is expanded by transmission voltage level losses and substation thermal loading. 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, finally, divided by the associated incremental substation capacity to get dollars / 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 "Substation Investment" (Sheet 'DistSub2') shows the detail of the substation calculation. "Distribution Substation Costs / kW 2021 Dollars" (Sheet 'DistSub1') shows the annualized cost in \$/kW.

The marginal cost of services includes the costs of new service drop investment 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.

The metering category includes 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.

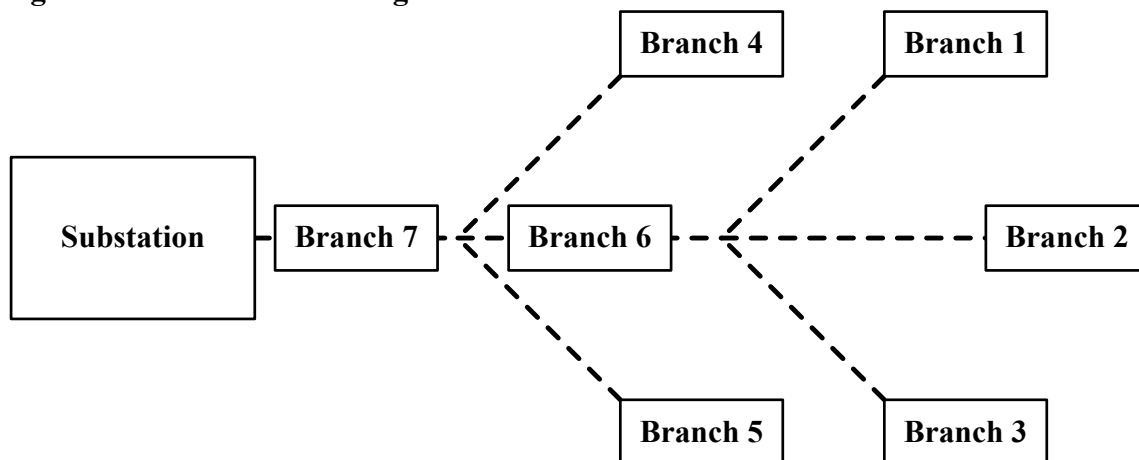
Weighted average installed service drop cost calculations are located on Sheets 'Services 1' through 'Services 3' and the weighted average installed meter cost calculations are included on Sheets 'Meters 1' through 'Meters 5'. The customer accounting and informational expense calculation is on page "Summary of Customer Accounting Expense by Schedule" (Sheet 'Cust Exp Sum'). These calculations are brought together on "Marginal Distribution & Billing Costs" (Sheet 'Table 6') to calculate metering reading, billing, collections and customer service related costs (\$/Customer/Yr).

**PacifiCorp  
Distribution Circuit Model  
PacifiCorp Distribution Circuit Model**

**General Overview**

The PacifiCorp Distribution Circuit Model is included in Exhibit PAC/1407, Sheets PC 3 through PC 14 and 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 of 26.20 poles per mile to the state average poles per mile. For example, Oregon has an average of 26.13 poles per mile. Figure 2 shows the circuit cost per mile calculation for Oregon.

**Figure 2 – Adjusted Oregon Line Costs per Mile**

	State Specific Account 364 Pole Statistics				Adjustment
	Poles	Pole Feet	Pole Miles	Poles / Mile	Factor
California	55,482	12,544,659	2,376	23.35	0.884
Idaho	97,406	21,318,575	4,038	24.12	0.913
Oregon	377,374	74,711,073	14,150	26.67	1.009
Utah	332,602	61,493,319	11,646	28.56	1.081
Washington	99,980	16,626,029	3,149	31.75	1.202
Wyoming	157,847	37,272,116	7,059	22.36	0.846
Total	1,120,691	223,965,771	42,418	26.42	1.000
	Account 364 Pole Cost per Mile			Account 365	Total Line
	Pole Cost	Adjustment	Adjusted	Conductor	Construction
Wire Size	per Mile	Factor	Pole Cost	Cost per Mile	Cost
1 Phase - 1/0 ACSR	\$25,517	1.009	\$25,758	\$12,789	\$38,547
3 Phase - 1/0 ACSR	\$48,426	1.009	\$48,883	\$28,548	\$77,431
3 Phase - 447 AAC & 4/0 AAC	\$54,011	1.009	\$54,521	\$62,952	\$117,473
3 Phase -795 AAC & 477 AAC	\$56,143	1.009	\$56,673	\$110,173	\$166,846

### 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**

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Hypothetical Circuit Branch							Branch
Class	1	2	3	4	5	6	7	Total
Res - Schedule 4 (sec)	0.38%	0.38%	0.38%	1.83%	1.83%	1.83%	93.37%	100.00%
GS - Schedule 23 - 0-15 kW (sec)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
GS - Schedule 23 - 15+ kW (sec)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
GS - Schedule 23 - Primary (pri)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
GS - Schedule 28 - 0-50 kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
GS - Schedule 28 - 51-100 kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
GS - Schedule 28 - 100+ kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
GS - Schedule 28 - Primary (pri)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
GS - Schedule 30 - 0-300 kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
GS - Schedule 30 - 300+ kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
GS - Schedule 30 - Primary (pri)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
Irrigation - Sch 41	1.10%	1.10%	1.10%	7.97%	7.97%	7.97%	72.78%	100.00%
LPS - Schedule 48 - 1 - 4 MW (sec)	1.03%	1.03%	1.03%	1.37%	1.37%	1.37%	92.82%	100.00%
LPS - Schedule 48 - 1 - 4 MW (pri)	1.03%	1.03%	1.03%	1.37%	1.37%	1.37%	92.82%	100.00%
LPS - Schedule 48 - > 4 MW (sec)	Large Customers are on dedicated circuits and are not included here							
LPS - Schedule 48 - > 4 MW (pri)	Large Customers are on dedicated circuits and are not included here							

### 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**

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Hypothetical Circuit Branch							
Class	1	2	3	4	5	6	7	Total
Res - Schedule 4 (sec)	3.68	3.68	3.68	17.98	17.98	17.98	915.63	980.61
GS - Schedule 23 - 0-15 kW (sec)	0.97	0.97	0.97	3.54	3.54	3.54	118.99	132.50
GS - Schedule 23 - 15+ kW (sec)	0.20	0.20	0.20	0.73	0.73	0.73	24.56	27.35
GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.01	0.01	0.01	0.20	0.22
GS - Schedule 28 - 0-50 kW (sec)	0.04	0.04	0.04	0.14	0.14	0.14	8.41	8.94
GS - Schedule 28 - 51-100 kW (sec)	0.03	0.03	0.03	0.10	0.10	0.10	6.21	6.60
GS - Schedule 28 - 100+ kW (sec)	0.02	0.02	0.02	0.06	0.06	0.06	3.51	3.73
GS - Schedule 28 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.13
GS - Schedule 30 - 0-300 kW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.39	0.41
GS - Schedule 30 - 300+ kW (sec)	0.00	0.00	0.00	0.01	0.01	0.01	0.98	1.02
GS - Schedule 30 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.10
Irrigation - Sch 41	0.14	0.14	0.14	0.99	0.99	0.99	9.02	12.40
LPS - Schedule 48 - 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.17
LPS - Schedule 48 - 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.12
LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
Total	5.08	5.08	5.08	23.55	23.55	23.55	1,088.39	1,174.30

### 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**

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Hypothetical Circuit Branch							
Class	1	2	3	4	5	6	7	Total
Res - Schedule 4 (sec)	8.97	8.97	8.97	43.77	43.77	43.77	2,229.56	2,387.77
GS - Schedule 23 - 0-15 kW (sec)	1.15	1.15	1.15	4.21	4.21	4.21	141.78	157.89
GS - Schedule 23 - 15+ kW (sec)	1.29	1.29	1.29	4.70	4.70	4.70	158.14	176.10
GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.02	0.02	0.02	0.56	0.62
GS - Schedule 28 - 0-50 kW (sec)	0.56	0.56	0.56	1.92	1.92	1.92	118.39	125.85
GS - Schedule 28 - 51-100 kW (sec)	0.83	0.83	0.83	2.82	2.82	2.82	174.08	185.04
GS - Schedule 28 - 100+ kW (sec)	1.06	1.06	1.06	3.61	3.61	3.61	222.32	236.32
GS - Schedule 28 - Primary (pri)	0.03	0.03	0.03	0.09	0.09	0.09	5.32	5.66
GS - Schedule 30 - 0-300 kW (sec)	0.15	0.15	0.15	0.51	0.51	0.51	50.36	52.34
GS - Schedule 30 - 300+ kW (sec)	0.72	0.72	0.72	2.52	2.52	2.52	248.00	257.71
GS - Schedule 30 - Primary (pri)	0.07	0.07	0.07	0.25	0.25	0.25	24.37	25.32
Irrigation - Sch 41	1.28	1.28	1.28	9.28	9.28	9.28	84.66	116.32
LPS - Schedule 48 - 1 - 4 MW (sec)	1.36	1.36	1.36	1.82	1.82	1.82	123.37	132.91
LPS - Schedule 48 - 1 - 4 MW (pri)	1.28	1.28	1.28	1.71	1.71	1.71	115.91	124.88
LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
<b>Total</b>	<b>18.75</b>	<b>18.75</b>	<b>18.75</b>	<b>77.21</b>	<b>77.21</b>	<b>77.21</b>	<b>3,696.84</b>	<b>3,984.72</b>



### 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, as shown in figure 6. 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, costs for each branch and miles per branch broken out by single and three-phase for Oregon.

**Figure 6 – Adjusted Oregon Line Costs per Mile**

Wire Size	Account 364 Pole Cost per Mile			Account 365	Total Line
	Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost	Conductor Cost per Mile	Construction Cost
1 Phase - 1/0 ACSR	\$25,517	1.009	\$25,758	\$12,789	\$38,547
3 Phase - 1/0 ACSR	\$48,426	1.009	\$48,883	\$28,548	\$77,431
3 Phase - 447 AAC & 4/0 AAC	\$54,011	1.009	\$54,521	\$62,952	\$117,473
3 Phase - 795 AAC & 477 AAC	\$56,143	1.009	\$56,673	\$110,173	\$166,846
Costs for Branches 1,2,3,4,5					
	1 Phase - 1/0 ACSR	3 Phase - 1/0 ACSR	Total		
Poles	\$47,499	\$167,408	\$214,907		
Conductors	\$23,583	\$97,767	\$121,350		
Total	\$71,082	\$265,175	\$336,257		
Costs for Branch 6					
	3 Phase - 447 AAC & 4/0 AAC	3 Phase - 795 AAC & 477 AAC		Miles per Branch 5.27	
Poles	\$287,255	\$298,594		Single Phase Miles Per Branch 1.84	
Conductors	\$331,674	\$580,467		Three Phase Miles Per Branch 3.42	
Total	\$618,929	\$879,060			

### 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 includes the total cost per circuit branch in columns (A) and (B), and the allocation of total cost between commitment and demand in columns (C) through (F) for Oregon.

**Figure 7 – Oregon Hypothetical Circuit Model Branch Costs**

Conductors Type	(A)		(B)		(C)		(D)		(E)		(F)	
	Total Cost				Commitment Cost				Demand Cost			
	Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
Branch 1												
1 Phase - 1/0 ACSR	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583						
3 Phase - 1/0 ACSR	\$ 167,408	\$ 97,767	\$ 167,408	\$ 97,767	\$ 88,212	\$ 43,798	\$ 79,196	\$ 53,969				
Total segment	\$ 214,907	\$ 121,350	\$ 214,907	\$ 121,350	\$ 135,711	\$ 67,381	\$ 79,196	\$ 53,969				
Branch 2												
1 Phase - 1/0 ACSR	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583						
3 Phase - 1/0 ACSR	\$ 167,408	\$ 97,767	\$ 167,408	\$ 97,767	\$ 88,212	\$ 43,798	\$ 79,196	\$ 53,969				
Total Segments	\$ 214,907	\$ 121,350	\$ 214,907	\$ 121,350	\$ 135,711	\$ 67,381	\$ 79,196	\$ 53,969				
Branch 3												
1 Phase - 1/0 ACSR	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583						
3 Phase - 1/0 ACSR	\$ 167,408	\$ 97,767	\$ 167,408	\$ 97,767	\$ 88,212	\$ 43,798	\$ 79,196	\$ 53,969				
Total Segments	\$ 214,907	\$ 121,350	\$ 214,907	\$ 121,350	\$ 135,711	\$ 67,381	\$ 79,196	\$ 53,969				
Branch 4												
1 Phase - 1/0 ACSR	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583						
3 Phase - 1/0 ACSR	\$ 167,408	\$ 97,767	\$ 167,408	\$ 97,767	\$ 88,212	\$ 43,798	\$ 79,196	\$ 53,969				
Total Segments	\$ 214,907	\$ 121,350	\$ 214,907	\$ 121,350	\$ 135,711	\$ 67,381	\$ 79,196	\$ 53,969				
Branch 5												
1 Phase - 1/0 ACSR	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583						
3 Phase - 1/0 ACSR	\$ 167,408	\$ 97,767	\$ 167,408	\$ 97,767	\$ 88,212	\$ 43,798	\$ 79,196	\$ 53,969				
Total Segments	\$ 214,907	\$ 121,350	\$ 214,907	\$ 121,350	\$ 135,711	\$ 67,381	\$ 79,196	\$ 53,969				
Branch 6												
3 Phase - 447 AAC & 4/0 AAC	\$ 287,255	\$ 331,674	\$ 287,255	\$ 331,674	\$ 135,711	\$ 67,381	\$ 151,544	\$ 264,293				
Total Segments	\$ 287,255	\$ 331,674	\$ 287,255	\$ 331,674	\$ 135,711	\$ 67,381	\$ 151,544	\$ 264,293				
Branch 7												
3 Phase -795 AAC & 477 AAC	\$ 298,594	\$ 580,467	\$ 298,594	\$ 580,467	\$ 135,711	\$ 67,381	\$ 162,883	\$ 513,086				
Total segment	\$ 298,594	\$ 580,467	\$ 298,594	\$ 580,467	\$ 135,711	\$ 67,381	\$ 162,883	\$ 513,086				

### 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 Demand Calculations, Cost Assignment**

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Hypothetical Circuit Branch								
	1	2	3	4	5	6	7		
% customer	14.05%	14.05%	14.05%			57.86%		100.00%	
Branch 6 Cost	\$ 21,288	\$ 21,288	\$ 21,288			\$ 87,679		\$ 151,544	\$ / kW
% customer	0.47%	0.47%	0.47%	1.94%	1.94%		92.78%	100.00%	
Branch 7 Cost	\$ 766	\$ 766	\$ 766	\$ 3,156	\$ 3,156	\$ 3,156	\$ 151,115	\$ 162,883	
Branch Commitment Cost	\$ 79,196	\$ 79,196	\$ 79,196	\$ 79,196	\$ 79,196				Average
Total	\$ 101,251	\$ 101,251	\$ 101,251	\$ 82,352	\$ 82,352	\$ 90,835	\$ 151,115	\$ 710,408	\$ 178.28
								Total	
								Demand	\$ Per
Class Cost per Branch	1	2	3	4	5	6	7	Cost	kW
Res - Schedule 4 (sec)	\$ 48,440	\$ 48,440	\$ 48,440	\$ 46,683	\$ 46,683	\$ 51,491	\$ 91,137	\$ 381,314	\$ 159.69
GS - Schedule 23 - 0-15 kW (sec)	\$ 6,233	\$ 6,233	\$ 6,233	\$ 4,494	\$ 4,494	\$ 4,957	\$ 5,796	\$ 38,439	\$ 243.46
GS - Schedule 23 - 15+ kW (sec)	\$ 6,952	\$ 6,952	\$ 6,952	\$ 5,012	\$ 5,012	\$ 5,529	\$ 6,464	\$ 42,874	\$ 243.46
GS - Schedule 23 - Primary (pri)	\$ 25	\$ 25	\$ 25	\$ 18	\$ 18	\$ 20	\$ 23	\$ 151	\$ 243.46
GS - Schedule 28 - 0-50 kW (sec)	\$ 3,041	\$ 3,041	\$ 3,041	\$ 2,049	\$ 2,049	\$ 2,260	\$ 4,840	\$ 20,319	\$ 161.46
GS - Schedule 28 - 51-100 kW (sec)	\$ 4,471	\$ 4,471	\$ 4,471	\$ 3,012	\$ 3,012	\$ 3,323	\$ 7,116	\$ 29,876	\$ 161.46
GS - Schedule 28 - 100+ kW (sec)	\$ 5,710	\$ 5,710	\$ 5,710	\$ 3,847	\$ 3,847	\$ 4,243	\$ 9,088	\$ 38,155	\$ 161.46
GS - Schedule 28 - Primary (pri)	\$ 137	\$ 137	\$ 137	\$ 92	\$ 92	\$ 102	\$ 218	\$ 913	\$ 161.46
GS - Schedule 30 - 0-300 kW (sec)	\$ 788	\$ 788	\$ 788	\$ 545	\$ 545	\$ 601	\$ 2,059	\$ 6,115	\$ 116.84
GS - Schedule 30 - 300+ kW (sec)	\$ 3,882	\$ 3,882	\$ 3,882	\$ 2,683	\$ 2,683	\$ 2,960	\$ 10,138	\$ 30,112	\$ 116.84
GS - Schedule 30 - Primary (pri)	\$ 381	\$ 381	\$ 381	\$ 264	\$ 264	\$ 291	\$ 996	\$ 2,958	\$ 116.84
Irrigation - Sch 41	\$ 6,911	\$ 6,911	\$ 6,911	\$ 9,893	\$ 9,893	\$ 10,913	\$ 3,461	\$ 54,893	\$ 471.90
LPS - Schedule 48 - 1 - 4 MW (sec)	\$ 7,363	\$ 7,363	\$ 7,363	\$ 1,939	\$ 1,939	\$ 2,138	\$ 5,043	\$ 33,146	\$ 249.38
LPS - Schedule 48 - 1 - 4 MW (pri)	\$ 6,917	\$ 6,917	\$ 6,917	\$ 1,821	\$ 1,821	\$ 2,009	\$ 4,738	\$ 31,142	\$ 249.38
LPS - Schedule 48 - > 4 MW (sec)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
LPS - Schedule 48 - > 4 MW (pri)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Check Total	\$ 101,251	\$ 101,251	\$ 101,251	\$ 82,352	\$ 82,352	\$ 90,835	\$ 151,115	\$ 710,408	

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 Commitment Calculations, Cost Assignment**

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Hypothetical Circuit Branch								
	1	2	3	4	5	6	7		
% customer	14.05%	14.05%	14.05%			57.86%		100.00%	
Branch 6 Cost	\$ 37,127	\$ 37,127	\$ 37,127			\$ 152,912		\$ 264,293	\$ / kW
% customer	0.47%	0.47%	0.47%	1.94%	1.94%		92.78%	100.00%	
Branch 7 Cost	\$ 2,414	\$ 2,414	\$ 2,414	\$ 9,942	\$ 9,942	\$ 9,942	\$ 476,017	\$ 513,086	
Branch Commitment Cost	\$ 53,969	\$ 53,969	\$ 53,969	\$ 53,969	\$ 53,969				Average
Total	\$ 93,510	\$ 93,510	\$ 93,510	\$ 63,911	\$ 63,911	\$ 162,854	\$ 476,017	\$ 1,047,223	\$ 262.81
								Total Demand	\$ Per
Class Cost per Branch	1	2	3	4	5	6	7	Cost	kW
Res - Schedule 4 (sec)	\$ 44,737	\$ 44,737	\$ 44,737	\$ 36,229	\$ 36,229	\$ 92,316	\$ 287,085	\$ 586,070	\$ 245.45
GS - Schedule 23 - 0-15 kW (sec)	\$ 5,756	\$ 5,756	\$ 5,756	\$ 3,488	\$ 3,488	\$ 8,887	\$ 18,256	\$ 51,387	\$ 325.47
GS - Schedule 23 - 15+ kW (sec)	\$ 6,421	\$ 6,421	\$ 6,421	\$ 3,890	\$ 3,890	\$ 9,912	\$ 20,363	\$ 57,317	\$ 325.47
GS - Schedule 23 - Primary (pri)	\$ 23	\$ 23	\$ 23	\$ 14	\$ 14	\$ 35	\$ 72	\$ 202	\$ 325.47
GS - Schedule 28 - 0-50 kW (sec)	\$ 2,808	\$ 2,808	\$ 2,808	\$ 1,590	\$ 1,590	\$ 4,051	\$ 15,245	\$ 30,900	\$ 245.54
GS - Schedule 28 - 51-100 kW (sec)	\$ 4,129	\$ 4,129	\$ 4,129	\$ 2,338	\$ 2,338	\$ 5,957	\$ 22,415	\$ 45,435	\$ 245.54
GS - Schedule 28 - 100+ kW (sec)	\$ 5,273	\$ 5,273	\$ 5,273	\$ 2,986	\$ 2,986	\$ 7,608	\$ 28,627	\$ 58,026	\$ 245.54
GS - Schedule 28 - Primary (pri)	\$ 126	\$ 126	\$ 126	\$ 71	\$ 71	\$ 182	\$ 685	\$ 1,389	\$ 245.54
GS - Schedule 30 - 0-300 kW (sec)	\$ 728	\$ 728	\$ 728	\$ 423	\$ 423	\$ 1,078	\$ 6,485	\$ 10,593	\$ 202.41
GS - Schedule 30 - 300+ kW (sec)	\$ 3,586	\$ 3,586	\$ 3,586	\$ 2,083	\$ 2,083	\$ 5,307	\$ 31,934	\$ 52,162	\$ 202.41
GS - Schedule 30 - Primary (pri)	\$ 352	\$ 352	\$ 352	\$ 205	\$ 205	\$ 521	\$ 3,137	\$ 5,125	\$ 202.41
Irrigation - Sch 41	\$ 6,383	\$ 6,383	\$ 6,383	\$ 7,678	\$ 7,678	\$ 19,565	\$ 10,901	\$ 64,969	\$ 558.52
LPS - Schedule 48 - 1 - 4 MW (sec)	\$ 6,800	\$ 6,800	\$ 6,800	\$ 1,505	\$ 1,505	\$ 3,834	\$ 15,886	\$ 43,128	\$ 324.48
LPS - Schedule 48 - 1 - 4 MW (pri)	\$ 6,388	\$ 6,388	\$ 6,388	\$ 1,414	\$ 1,414	\$ 3,602	\$ 14,925	\$ 40,519	\$ 324.48
LPS - Schedule 48 - > 4 MW (sec)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
LPS - Schedule 48 - > 4 MW (pri)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Check Total	\$ 93,510	\$ 93,510	\$ 93,510	\$ 63,911	\$ 63,911	\$ 162,854	\$ 476,017	\$ 1,047,223	

## 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. Table 10 shows this calculation for Oregon.

**Table 10 – Oregon Dedicated Circuit Trunk Costs for Large Customers**

	Voltage Delivery			
	Large GS + 4 MW (pri)		Large GS + 4 MW (sec)	
	Poles	Conductor	Poles	Conductor
Construction Cost Per Mile	\$ 56,673	\$ 110,173	\$ 56,673	\$ 110,173
Average Trunk Length	0.67 miles		0.67 miles	
Total Construction Cost	\$ 37,971	\$ 73,816	\$ 37,971	\$ 73,816
Customer Peak Demand	4,256 kW		4,764 kW	
Demand Cost \$/kW	\$8.92	\$17.34	\$7.97	\$15.49

## Summary

The final step in the circuit model is to bring the various results together in a single summary page. Table 11 shows the results calculated earlier in the study. Note that the \$/customer and \$/circuit kW is the distribution investment to serve that customer and not the price that the customer is expected to pay.

**Table 11 – Oregon Summary of Results**

Class	Commitment \$/Customer		Demand \$/Dist. kW		Typical circuit		Demand \$/circuit	
	Poles	Conductor	Poles	Conductor	Customers	kW	Poles	Conductor
Res - Schedule 4 (sec)	\$ 734.13	\$ 364.50	\$ 159.69	\$ 245.45	980.6	2,387.77	\$ 381,314	\$ 586,070
GS - Schedule 23 - 0-15 kW (sec)	\$ 1,158.69	\$ 575.29	\$ 243.46	\$ 325.47	132.5	157.89	\$ 38,439	\$ 51,387
GS - Schedule 23 - 15+ kW (sec)	\$ 1,158.69	\$ 575.29	\$ 243.46	\$ 325.47	27.3	176.10	\$ 42,874	\$ 57,317
GS - Schedule 23 - Primary (pri)	\$ 1,158.69	\$ 575.29	\$ 243.46	\$ 325.47	0.2	0.62	\$ 151	\$ 202
GS - Schedule 28 - 0-50 kW (sec)	\$ 739.44	\$ 367.14	\$ 161.46	\$ 245.54	8.9	125.85	\$ 20,319	\$ 30,900
GS - Schedule 28 - 51-100 kW (sec)	\$ 739.44	\$ 367.14	\$ 161.46	\$ 245.54	6.6	185.04	\$ 29,876	\$ 45,435
GS - Schedule 28 - 100+ kW (sec)	\$ 739.44	\$ 367.14	\$ 161.46	\$ 245.54	3.7	236.32	\$ 38,155	\$ 58,026
GS - Schedule 28 - Primary (pri)	\$ 739.44	\$ 367.14	\$ 161.46	\$ 245.54	0.1	5.66	\$ 913	\$ 1,389
GS - Schedule 30 - 0-300 kW (sec)	\$ 512.16	\$ 254.29	\$ 116.84	\$ 202.41	0.4	52.34	\$ 6,115	\$ 10,593
GS - Schedule 30 - 300+ kW (sec)	\$ 512.16	\$ 254.29	\$ 116.84	\$ 202.41	1.0	257.71	\$ 30,112	\$ 52,162
GS - Schedule 30 - Primary (pri)	\$ 512.16	\$ 254.29	\$ 116.84	\$ 202.41	0.1	25.32	\$ 2,958	\$ 5,125
Irrigation - Sch 41	\$ 2,350.27	\$ 1,166.92	\$ 471.90	\$ 558.52	12.4	116.32	\$ 54,893	\$ 64,969
LPS - Schedule 48 - 1 - 4 MW (sec)	\$ 1,173.53	\$ 582.66	\$ 249.38	\$ 324.48	0.2	132.91	\$ 33,146	\$ 43,128
LPS - Schedule 48 - 1 - 4 MW (pri)	\$ 1,173.53	\$ 582.66	\$ 249.38	\$ 324.48	0.1	124.88	\$ 31,142	\$ 40,519
Total -	\$ 808.97	\$ 401.66	\$ 178.28	\$ 262.81	1,174.3	3,984.7	\$ 710,408	\$ 1,047,223
Large GS + 4 MW (sec)	\$ -	\$ -	\$ 7.97	\$ 15.49	-	4,763.92	\$ 37,971	\$ 73,816
Large GS + 4 MW (pri)	\$ -	\$ -	\$ 8.92	\$ 17.34	-	4,256.39	\$ 37,971	\$ 73,816
							\$ 786,350	\$ 1,194,855

Table 1

PacifiCorp  
Oregon Marginal Cost Study  
Summary of Marginal Costs  
Demand & Energy in Mills/kWh  
December 2023 Dollars

Line	Description		(A)	(B)	(C)	(D)	(E)	(F)
			Energy			Demand & Energy		
			1 Year	10 Year	20 Year	1 Year	10 Year	20 Year
1	Res - Schedule 4	(sec)	34.51	37.14	38.13	34.51	73.19	74.15
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	34.51	37.14	38.13	34.51	68.05	69.01
5	15+ kW	(sec)	34.51	37.14	38.13	34.51	68.15	69.11
6	Primary	(pri)	33.98	36.57	37.54	33.98	58.83	59.75
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	34.51	37.14	38.13	34.51	64.69	65.66
10	51-100 kW	(sec)	34.51	37.14	38.13	34.51	64.01	64.98
11	100 + kW	(sec)	34.51	37.14	38.13	34.51	63.09	64.06
12	Primary	(pri)	33.98	36.57	37.54	33.98	60.09	61.04
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	34.51	37.14	38.13	34.51	61.22	62.19
16	300+ kW	(sec)	34.51	37.14	38.13	34.51	60.03	61.00
17	Primary	(pri)	33.98	36.57	37.54	33.98	59.43	60.38
18								
19	LPS - Schedule 48							
20	1 - 4 MW	(sec)	34.51	37.14	38.13	34.51	63.98	64.95
21	1 - 4 MW	(pri)	33.98	36.57	37.54	33.98	61.50	62.45
22	> 4 MW	(sec)	34.51	37.14	38.13	34.51	53.14	54.12
23	> 4 MW	(pri)	33.98	36.57	37.54	33.98	52.07	53.02
24	Trans	(trn)	33.08	35.61	36.56	33.08	47.37	48.30
25								
26								
27	Schedule 41- Irrigation	(sec)	34.51	37.14	38.13	34.51	85.12	86.09

Energy costs include both generation and transmission energy-related costs.

Table 2

PacifiCorp  
Oregon Marginal Cost Study  
Summary of Marginal Costs  
Commitment and Billing in \$ / Customer / Month  
December 2023 Dollars

Line	Description		(A)	(B)
			1 Year	10 & 20 Year
1	Res - Schedule 4	(sec)	\$11.91	\$28.85
2				
3	GS - Schedule 23			
4	0-15 kW	(sec)	14.10	43.93
5	15+ kW	(sec)	22.40	56.95
6	Primary	(pri)	100.52	116.01
7				
8	GS - Schedule 28			
9	0-50 kW	(sec)	25.63	94.56
10	51-100 kW	(sec)	26.58	103.56
11	100 + kW	(sec)	55.26	137.78
12	Primary	(pri)	102.88	112.77
13				
14	GS - Schedule 30			
15	0-300 kW	(sec)	65.97	155.31
16	300+ kW	(sec)	97.99	187.59
17	Primary	(pri)	113.56	120.41
18				
19	LPS - Schedule 48			
20	1 - 4 MW	(sec)	331.79	430.23
21	1 - 4 MW	(pri)	183.00	198.69
22	> 4 MW	(sec)	331.79	414.54
23	> 4 MW	(pri)	183.00	183.00
24	Trans	(trn)	1,743.47	1,743.47
25				
26				
27	Schedule 41- Irrigation	(sec)	6.85	106.38

## Footnote:

Short-run commitment and billing costs include the cost of metering, meter overhead, maintenance, service drops, service drop overhead and maintenance, customer accounting, informational expenses, and billing expenses.





Table 4

PacifiCorp  
Oregon Marginal Cost Study  
Summary of Marginal Generation Costs in Nominal Dollars

	(A) (B) + (C)	(B)	(C)	(D)
Year	Resource Cost (Mills/kWh)	Energy Only (Mills/kWh)	Capacity Only (Mills/kWh)	Capacity Only (\$/kW)
2023	47.10	31.96	15.14	93.53
2024	47.87	32.38	15.49	95.66
2025	50.42	34.58	15.84	97.84
2026	52.22	36.02	16.20	100.07
2027	53.99	37.42	16.57	102.36
2028	56.18	39.23	16.95	104.70
2029	59.13	41.79	17.34	107.09
2030	60.88	43.14	17.74	109.53
2031	62.56	44.42	18.14	112.03
2032	63.65	45.10	18.55	114.58
2033	65.79	46.81	18.98	117.19
2034	66.77	47.36	19.41	119.86
2035	67.72	47.87	19.85	122.60
2036	69.02	48.72	20.30	125.39
2037	70.76	49.99	20.77	128.25
2038	72.30	51.06	21.24	131.17
2039	74.95	53.22	21.73	134.17
2040	77.47	55.25	22.22	137.23
2041	79.25	56.52	22.73	140.36
2042	81.06	57.81	23.25	143.56
<u>2023 (1 Year)</u>	<u>Mills/kWh</u>	<u>Mills/kWh</u>	<u>Mills/kWh</u>	<u>\$/kW</u>
	47.10	31.96	15.14	93.53
<u>2023 - 2027 (5 Year, Short Run)</u>				
Sum of PV Costs @ 7.21%	218.87	149.81	69.06	426.56
Annual Cost @ 21.92%	47.98	32.84	15.14	93.50
<u>2023 - 2032 (10 Year, Medium Run)</u>				
Sum of PV Costs @ 7.21%	404.72	281.07	123.65	763.68
Annual Cost @ 12.24%	49.53	34.40	15.13	93.47
<u>2023 - 2042 (20 Year, Long Run)</u>				
Sum of PV Costs @ 7.21%	670.51	469.63	200.88	1,240.61
Annual Cost @ 7.52%	50.43	35.32	15.11	93.29

Table 5

PacifiCorp  
Oregon Marginal Cost Study  
Marginal Cost of  
Transmission Investment and Associated Expenses

Line	Item	\$
1	Growth Related Investments - (2022 to 2026 in \$000s)	\$158,702
2		
3	System Growth MW from 2022 to 2026	2,879
4		
5	Marginal Investment (line 1/line 3)	\$55.13 / kW
6		
7	Annualized Investment @ 6.16%	3.40 / kW
8	Admin. & General Factor @ 0.60%	0.33
9	Annual O&M Expenses @ 1.176%	0.65 / kW
10	Annualized Marginal Cost	\$4.38 / kW
11		
12	Marginal Cost of Demand-Related Transmission	\$4.38 / kW
13		
14	Marginal Cost of Energy-Related Transmission (Line 10 - Line 12)	\$0.00 / kW
15	Marginal Cost of Energy-Related Transmission	\$0.00000 / kWh
16	\$0.00 / (8760 x 77.45% LF)	

Table 6

PacifiCorp  
Oregon Marginal Cost Study  
Marginal Distribution & Billing Costs  
2023 Dollars

Line	Description	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
		Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48				Ing	
		(sec)	0-15 kW (sec)	15+ kW (sec)	Primary (pri)	0-50 kW (sec)	51-100 kW (sec)	100+ kW (sec)	Primary (pri)	0-300 kW (sec)	300+ kW (sec)	Primary (pri)	1 - 4 MW (sec)	1 - 4 MW (pri)	> 4 MW (sec)	> 4 MW (pri)	Trans (trn)	Sch 41 (sec)
1	<b>Demand Costs (\$/kW)</b>																	
2																		
3	Dist-Poles	\$11.80	\$18.00	\$18.00	\$18.00	\$11.93	\$11.93	\$11.93	\$11.93	\$8.64	\$8.64	\$8.64	\$18.43	\$18.43	\$0.59	\$0.66	\$0.00	\$34.88
4	Dist-Conductors	\$18.14	\$24.06	\$24.06	\$24.06	\$18.15	\$18.15	\$18.15	\$18.15	\$14.96	\$14.96	\$14.96	\$23.98	\$23.98	\$1.15	\$1.28	\$0.00	\$41.28
5	Dist-Substation	\$12.69	\$12.69	\$12.69	\$12.69	\$12.69	\$12.69	\$12.69	\$12.69	\$12.69	\$12.69	\$12.69	\$12.69	\$12.69	\$12.69	\$12.69	\$0.00	\$12.69
6	Dist. O&M @ 45.05% of Investment	\$19.20	\$24.66	\$24.66	\$24.66	\$19.27	\$19.27	\$19.27	\$19.27	\$16.35	\$16.35	\$16.35	\$24.82	\$24.82	\$6.50	\$6.59	\$0.00	\$40.02
7	Total \$/Dist. kW	\$61.83	\$79.41	\$79.41	\$79.41	\$62.03	\$62.03	\$62.03	\$62.03	\$52.63	\$52.63	\$52.63	\$79.92	\$79.92	\$20.92	\$21.21	\$0.00	\$128.87
8																		
9	Dist-Transformers	\$1.02	\$1.02	\$1.02	\$0.00	\$1.02	\$1.02	\$1.02	\$0.00	\$1.02	\$1.02	\$0.00	\$1.02	\$0.00	\$1.02	\$0.00	\$0.00	\$1.02
10	Dist. O&M @ 45.05% of Investment	\$0.46	\$0.46	\$0.46	\$0.00	\$0.46	\$0.46	\$0.46	\$0.00	\$0.46	\$0.46	\$0.00	\$0.46	\$0.00	\$0.46	\$0.00	\$0.00	\$0.46
11	Total \$/Transformer kW	\$1.48	\$1.48	\$1.48	\$0.00	\$1.48	\$1.48	\$1.48	\$0.00	\$1.48	\$1.48	\$0.00	\$1.48	\$0.00	\$1.48	\$0.00	\$0.00	\$1.48
12																		
13	<b>Customer Costs (\$/Customer)</b>																	
14																		
15	<b>Commitment</b>																	
16																		
17	<b>Dist-Poles</b>	\$54.26	\$85.65	\$85.65	\$85.65	\$54.66	\$54.66	\$54.66	\$54.66	\$37.86	\$37.86	\$37.86	\$86.74	\$86.74	\$0.00	\$0.00	\$0.00	\$173.72
18	Dist-Conductors	\$26.94	\$42.52	\$42.52	\$42.52	\$27.14	\$27.14	\$27.14	\$27.14	\$18.80	\$18.80	\$18.80	\$43.07	\$43.07	\$0.00	\$0.00	\$0.00	\$86.26
19	Dist-Transformers	\$58.91	\$118.65	\$157.59	\$0.00	\$488.44	\$555.07	\$600.86	\$0.00	\$682.44	\$684.58	\$0.00	\$684.58	\$0.00	\$684.58	\$0.00	\$0.00	\$563.42
20	Dist. O&M @ 45.05% of Investment	\$63.12	\$111.19	\$128.73	\$57.74	\$256.89	\$286.91	\$307.54	\$36.85	\$332.96	\$333.93	\$25.53	\$366.88	\$58.48	\$308.41	\$0.00	\$0.00	\$370.94
21	Total Commitment	\$203.23	\$358.01	\$414.49	\$185.91	\$827.13	\$923.78	\$990.19	\$118.65	\$1,072.06	\$1,075.17	\$82.19	\$1,181.28	\$188.29	\$992.99	\$0.00	\$0.00	\$1,194.34
22	Monthly Commitment	\$16.94	\$29.83	\$34.54	\$15.49	\$68.93	\$76.98	\$82.52	\$9.89	\$89.34	\$89.60	\$6.85	\$98.44	\$15.69	\$82.75	\$0.00	\$0.00	\$99.53
23																		
24	<b>Billing</b>																	
25																		
26	Dist-Service Drop	\$52.23	\$70.64	\$136.82	\$0.00	\$141.47	\$147.75	\$286.32	\$0.00	\$286.21	\$550.99	\$0.00	\$1,884.81	\$0.00	\$1,884.81	\$0.00	\$0.00	\$0.00
27	Dist. O&M @ 45.05% of Investment	\$23.53	\$31.82	\$61.64	\$0.00	\$63.73	\$66.56	\$128.99	\$0.00	\$128.94	\$248.22	\$0.00	\$849.11	\$0.00	\$849.11	\$0.00	\$0.00	\$0.00
28	Meter	\$13.94	\$14.83	\$17.04	\$699.25	\$19.17	\$20.52	\$106.55	\$699.25	\$106.89	\$107.03	\$699.25	\$129.58	\$699.25	\$129.58	\$699.25	\$11,946.58	\$20.53
29	Meter O&M @ 66.49% of Investment	\$9.27	\$9.86	\$11.33	\$464.93	\$12.75	\$13.64	\$70.85	\$464.93	\$71.07	\$71.16	\$464.93	\$86.16	\$464.93	\$86.16	\$464.93	\$7,943.28	\$13.65
30	Meter Reading	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
31	Billing & Collections	\$25.10	\$30.35	\$30.35	\$30.35	\$35.21	\$35.21	\$35.21	\$35.21	\$35.21	\$35.21	\$35.21	\$290.78	\$290.78	\$290.78	\$290.78	\$290.78	\$30.33
32	Uncollectables	\$9.64	\$2.49	\$2.49	\$2.49	\$25.02	\$25.02	\$25.02	\$25.02	\$148.58	\$148.58	\$148.58	\$696.73	\$696.73	\$696.73	\$696.73	\$696.73	\$8.29
33	Customer Service / Other	\$9.26	\$9.19	\$9.19	\$9.19	\$10.20	\$10.20	\$10.20	\$10.20	\$14.74	\$14.74	\$14.74	\$44.26	\$44.26	\$44.26	\$44.26	\$44.26	\$9.40
34	Total Billing	\$142.97	\$169.19	\$268.86	\$1,206.21	\$307.55	\$318.91	\$663.13	\$1,234.61	\$791.63	\$1,175.93	\$1,362.71	\$3,981.44	\$2,195.96	\$3,981.44	\$2,195.96	\$20,921.64	\$82.21
35	Monthly Billing	\$11.91	\$14.10	\$22.40	\$100.52	\$25.63	\$26.58	\$55.26	\$102.88	\$65.97	\$97.99	\$113.56	\$331.79	\$183.00	\$331.79	\$183.00	\$1,743.47	\$6.85
36																		
37	Total Customer (Commitment & Billing)	\$346.20	\$527.19	\$683.35	\$1,392.12	\$1,134.68	\$1,242.69	\$1,653.33	\$1,353.26	\$1,863.70	\$2,251.10	\$1,444.89	\$5,162.71	\$2,384.25	\$4,974.42	\$2,195.96	\$20,921.64	\$1,276.55
38	Monthly Customer (Commitment & Billing)	\$28.85	\$43.93	\$56.95	\$116.01	\$94.56	\$103.56	\$137.78	\$112.77	\$155.31	\$187.59	\$120.41	\$430.23	\$198.69	\$414.54	\$183.00	\$1,743.47	\$106.38
39																		

Table 7

PacifiCorp  
Oregon Marginal Cost Study  
20 Year Demand Costs Divided by Billing kW  
December 2023 Dollars

Line	Units Description / Function	Total	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48				Irrg - Sch 41	
			(sec)	0-15 kW (sec)	15+ kW (sec)	(pri)	0-50 kW (sec)	51-100 kW (sec)	100 + kW (sec)	Primary (pri)	0-300 kW (sec)	300+ kW (sec)	Primary (pri)	1 - 4 MW (sec)	1 - 4 MW (pri)	> 4 MW (sec)	> 4 MW (pri)	Trn (trn)	(sec)
1	Marginal Cost (\$000)																		
2																			
3	Generation	\$220,002	\$107,503	\$8,554	\$9,332	\$44	\$6,793	\$10,074	\$12,856	\$344	\$2,783	\$13,848	\$1,425	\$6,976	\$6,491	\$474	\$11,655	\$17,333	\$3,516
4	Transmission	\$10,329	\$5,047	\$402	\$438	\$2	\$319	\$473	\$604	\$16	\$131	\$650	\$67	\$328	\$305	\$22	\$547	\$814	\$165
5	Dist-Poles, Wire, Sub	\$153,213	\$84,870	\$7,207	\$8,039	\$28	\$4,488	\$6,599	\$8,427	\$199	\$1,584	\$7,797	\$756	\$6,106	\$5,661	\$109	\$2,724	\$0	\$8,618
6	Dist-Transformers	\$9,334	\$5,495	\$675	\$419	\$0	\$434	\$716	\$562	\$0	\$102	\$385	\$0	\$192	\$0	\$13	\$0	\$0	\$341
7																			
8	Average Billing kW @ Sales	8,497,531	5,094,228	598,673	371,428	5,687	269,617	444,697	349,255	12,225	63,411	239,143	24,614	119,399	146,695	8,225	229,520	309,205	211,511
9																			
10	Generation (\$/kW)		\$21.10	\$14.29	\$25.12	\$7.70	\$25.20	\$22.65	\$36.81	\$28.14	\$43.90	\$57.91	\$57.89	58.43	44.25	57.66	50.78	56.06	16.62
11	Transmission (\$/kW)		\$0.99	\$0.67	\$1.18	\$0.36	\$1.18	\$1.06	\$1.73	\$1.32	\$2.06	\$2.72	\$2.72	2.74	2.08	2.71	2.38	2.63	0.78
12	Dist-Poles, Wire, Sub (\$/kW)		\$16.66	\$12.04	\$21.64	\$4.92	\$16.64	\$14.84	\$24.13	\$16.29	\$24.97	\$32.61	\$30.71	51.14	38.59	13.29	11.87	0.00	40.74
13	Dist-Transformers (\$/kW)		\$1.08	\$1.13	\$1.13	\$0.00	\$1.61	\$1.61	\$1.61	\$0.00	\$1.61	\$1.61	\$0.00	1.61	0.00	1.61	0.00	0.00	1.61
14																			
15	Total Demand Related		\$39.83	\$28.12	\$49.08	\$12.98	\$44.63	\$40.17	\$64.28	\$45.75	\$72.54	\$94.84	\$91.32	\$113.92	\$84.92	\$75.26	\$65.03	\$58.69	\$59.76
16	Monthly Demand Related		\$3.32	\$2.34	\$4.09	\$1.08	\$3.72	\$3.35	\$5.36	\$3.81	\$6.04	\$7.90	\$7.61	\$9.49	\$7.08	\$6.27	\$5.42	\$4.89	\$4.98

Table 8

PacifiCorp  
Oregon Marginal Cost Study  
Marginal Cost Percentage  
December 2023 Dollars

Line	Description	(A) Marginal Cost (000s)	(B) Mills / kWh	(C) % of Total
1	Demand Related Marginal Cost			
2	Generation	\$220,002	15.84	18.7%
3	Transmission	\$10,329	0.74	0.9%
4	Dist. Poles, Cond., Subst.	\$153,213	11.03	13.0%
5	Dist. Transformers	\$9,372	0.67	0.8%
6	Total Demand Related	\$392,916	28.28	33.4%
7				
8	Energy Related Marginal Cost			
9	Generation	\$526,179	37.89	44.7%
10	Transmission	\$0	0.00	0.0%
11	Total Energy Related	\$526,179	37.89	44.7%
12				
13	Commitment & Billing			
14	Commitment	\$159,477	11.48	13.5%
15	Billing	\$98,701	7.11	8.4%
16	Total Commitment & Billing	\$258,178	18.59	21.9%
17				
18				
19	TOTAL MARGINAL COST	\$1,177,272	84.76	100.0%
20				
21				
22				

Note: Total MWh @ Sales = 13,886,900

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

Line	Calculation Component	Class	Units Description / Function	Total	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
					Residential	General Service - Schedule 23				General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48				Irrg - Sch 41
					(sec)	0-15 kW (sec)	15+ kW (sec)	Primary (pri)	0-50 kW (sec)	51-100 kW (sec)	100+ kW (sec)	Primary (pri)	0-300 kW (sec)	300+ kW (sec)	Primary (pri)	1 - 4 MW (sec)	1 - 4 MW (pri)	> 4 MW (sec)	> 4 MW (pri)	Trn (trn)	(sec)
1	Units	Demand	Peak MW @ Input-System		1,152	92	100	0	73	108	138	4	30	148	15	75	70	5	125	186	38
2	Units	Demand	Peak MW @ Input-Distribution		1,373	91	101	0	72	106	136	3	30	148	14	76	71	5	128	-	67
3	Units	Demand	Peak MW @ Input-Transformer		3,702	455	282	-	292	482	379	-	69	259	-	130	-	9	-	-	229
4																					
5	Units	Energy	Annual MWh @ Input		6,082,593	588,687	635,298	3,533	472,029	718,357	934,868	25,303	206,473	1,070,906	104,635	547,595	531,645	41,798	1,024,837	1,599,365	284,558
6																					
7	Units	Customer	Average		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	4,356
8	Units	Customer	Annual		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	7,997
9																					
10																					
11	S/Unit	Demand	Generation (S/System Peak kW)		\$93.47	\$93.47	\$93.47	\$93.47	\$93.47	\$93.47	\$93.47	\$93.47	\$93.47	\$93.47	\$93.47	\$93.47	\$93.47	\$93.47	\$93.47	\$93.47	\$93.47
12	S/Unit	Demand	Transmission (S/System Peak kW)		\$4.38	\$4.38	\$4.38	\$4.38	\$4.38	\$4.38	\$4.38	\$4.38	\$4.38	\$4.38	\$4.38	\$4.38	\$4.38	\$4.38	\$4.38	\$4.38	\$4.38
13	S/Unit	Demand	Dist-Poles (S/Dist. kW)		\$17.12	\$26.11	\$26.11	\$26.11	\$17.30	\$17.30	\$17.30	\$17.30	\$12.53	\$12.53	\$12.53	\$26.73	\$26.73	\$0.86	\$0.96	\$0.00	\$50.59
14	S/Unit	Demand	Dist-Cond (S/Dist. kW)		\$26.31	\$34.90	\$34.90	\$34.90	\$26.33	\$26.33	\$26.33	\$26.33	\$21.70	\$21.70	\$21.70	\$34.78	\$34.78	\$1.67	\$1.86	\$0.00	\$59.88
15	S/Unit	Demand	Dist-Substation (S/Dist. kW)		\$18.40	\$18.40	\$18.40	\$18.40	\$18.40	\$18.40	\$18.40	\$18.40	\$18.40	\$18.40	\$18.40	\$18.40	\$18.40	\$18.40	\$18.40	\$0.00	\$18.40
16	S/Unit	Demand	Dist-Transformers (S/Xfmr kW)		\$1.48	\$1.48	\$1.48	\$0.00	\$1.48	\$1.48	\$1.48	\$0.00	\$1.48	\$1.48	\$0.00	\$1.48	\$0.00	\$1.48	\$0.00	\$0.00	\$1.48
17																					
18	S/Unit	Energy	Generation Energy @ Input (S/kWh)		\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440	\$0.03440
19																					
20																					
21	S/Unit	Customer	Dist-Poles (S/Customer)		\$78.70	\$124.24	\$124.24	\$124.24	\$79.28	\$79.28	\$79.28	\$79.28	\$54.92	\$54.92	\$54.92	\$125.82	\$125.82	\$0.00	\$0.00	\$0.00	\$251.98
22	S/Unit	Customer	Dist-Conductor (S/Customer)		\$39.08	\$61.68	\$61.68	\$61.68	\$39.37	\$39.37	\$39.37	\$39.37	\$27.27	\$27.27	\$27.27	\$62.47	\$62.47	\$0.00	\$0.00	\$0.00	\$125.12
23	S/Unit	Customer	Dist-Transformers (S/Customer)		\$85.45	\$172.10	\$228.58	\$0.00	\$708.48	\$805.13	\$871.54	\$0.00	\$989.88	\$992.99	\$0.00	\$992.99	\$0.00	\$992.99	\$0.00	\$0.00	\$817.24
24	S/Unit	Customer	Dist-Service Drop (S/Customer)		\$75.76	\$102.46	\$198.46	\$0.00	\$205.20	\$214.31	\$415.31	\$0.00	\$415.15	\$799.21	\$0.00	\$2,733.92	\$0.00	\$2,733.92	\$0.00	\$0.00	\$0.00
25	S/Unit	Customer	Meters (S/Customer)		\$23.21	\$24.69	\$28.37	\$1,164.18	\$31.92	\$34.16	\$177.40	\$1,164.18	\$177.96	\$178.19	\$1,164.18	\$215.74	\$1,164.18	\$215.74	\$1,164.18	\$19,889.86	\$34.18
26	S/Unit	Customer	Meter Reading (S/Customer)		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
27	S/Unit	Customer	Billing & Collections (S/Customer)		\$25.10	\$30.35	\$30.35	\$30.35	\$35.21	\$35.21	\$35.21	\$35.21	\$35.21	\$35.21	\$35.21	\$290.78	\$290.78	\$290.78	\$290.78	\$290.78	\$30.33
28	S/Unit	Customer	Uncollectables (S/Customer)		\$9.64	\$2.49	\$2.49	\$2.49	\$25.02	\$25.02	\$25.02	\$25.02	\$148.58	\$148.58	\$148.58	\$696.73	\$696.73	\$696.73	\$696.73	\$696.73	\$8.29
29	S/Unit	Customer	Customer Service / Other (S/Customer)		\$9.26	\$9.19	\$9.19	\$9.19	\$10.20	\$10.20	\$10.20	\$10.20	\$14.74	\$14.74	\$14.74	\$44.26	\$44.26	\$44.26	\$44.26	\$44.26	\$9.40
30																					
31																					
32	\$000	Demand	Generation	\$220,427	\$107,710	\$8,570	\$9,350	\$44	\$6,806	\$10,094	\$12,881	\$345	\$2,789	\$13,875	\$1,428	\$6,989	\$6,504	\$475	\$11,677	\$17,367	\$3,523
33	\$000	Demand	Transmission	\$10,330	\$5,047	\$402	\$438	\$2	\$319	\$473	\$604	\$16	\$131	\$650	\$67	\$328	\$305	\$22	\$547	\$814	\$165
34	\$000	Demand	Dist-Poles	\$43,877	\$23,495	\$2,370	\$2,643	\$9	\$1,252	\$1,841	\$2,351	\$56	\$377	\$1,857	\$180	\$2,043	\$1,894	\$4	\$123	\$0	\$3,383
35	\$000	Demand	Dist-Conductor	\$64,749	\$36,118	\$3,168	\$3,533	\$12	\$1,905	\$2,800	\$3,577	\$85	\$653	\$3,215	\$312	\$2,658	\$2,464	\$9	\$238	\$0	\$4,004
36	\$000	Demand	Dist-Substations	\$44,587	\$25,258	\$1,670	\$1,863	\$6	\$1,331	\$1,957	\$2,500	\$59	\$554	\$2,726	\$264	\$1,406	\$1,304	\$96	\$2,363	\$0	\$1,230
37	\$000	Demand	Dist-Transformers	\$9,334	\$5,495	\$675	\$419	\$0	\$434	\$716	\$562	\$0	\$102	\$385	\$0	\$192	\$0	\$13	\$0	\$0	\$341
38	\$000	Demand	Total Demand	\$393,304	\$203,122	\$16,854	\$18,246	\$74	\$12,047	\$17,882	\$22,474	\$560	\$4,606	\$22,707	\$2,251	\$13,616	\$12,470	\$620	\$14,948	\$18,181	\$12,646
39																					
40	\$000	Energy	Generation	\$511,613	\$209,241	\$20,251	\$21,854	\$122	\$16,238	\$24,711	\$32,159	\$870	\$7,103	\$36,839	\$3,599	\$18,837	\$18,289	\$1,438	\$35,254	\$55,018	\$9,789
41	\$000	Energy	Transmission	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
42	\$000	Energy	Total Energy	\$511,613	\$209,241	\$20,251	\$21,854	\$122	\$16,238	\$24,711	\$32,159	\$870	\$7,103	\$36,839	\$3,599	\$18,837	\$18,289	\$1,438	\$35,254	\$55,018	\$9,789
43																					
44	\$000	Customer	Dist-Poles	\$55,496	\$42,111	\$8,672	\$1,790	\$14	\$382	\$282	\$160	\$5	\$12	\$29	\$3	\$12	\$8	\$0	\$0	\$0	\$2,015
45	\$000	Customer	Dist-Conductor	\$27,553	\$20,908	\$4,305	\$889	\$7	\$190	\$140	\$79	\$3	\$6	\$14	\$1	\$6	\$4	\$0	\$0	\$0	\$1,001
46	\$000	Customer	Dist-Transformers	\$76,429	\$45,720	\$12,013	\$3,293	\$0	\$3,414	\$2,868	\$1,754	\$0	\$211	\$527	\$0	\$91	\$0	\$1	\$0	\$0	\$6,535
47	\$000	Customer	Dist-Service Drop	\$53,903	\$40,536	\$7,153	\$2,859	\$0	\$989	\$763	\$836	\$0	\$88	\$424	\$0	\$252	\$0	\$3	\$0	\$0	\$0
48	\$000	Customer	Meters	\$16,147	\$12,418	\$1,724	\$409	\$134	\$154	\$122	\$357	\$80	\$38	\$95	\$62	\$20	\$71	\$0	\$33	\$159	\$273
49	\$000	Customer	Meter Reading	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
50	\$000	Customer	Billing & Collections	\$16,574	\$13,430	\$2,119	\$437	\$3	\$170	\$125	\$71	\$2	\$7	\$19	\$2	\$27	\$18	\$0	\$8	\$2	\$132
51	\$000	Customer	Uncollectables	\$5,914	\$5,155	\$174	\$36	\$0	\$121	\$89	\$50	\$2	\$32	\$79	\$8	\$64	\$43	\$1	\$20	\$6	\$36
52	\$000	Customer	Customer Service / Other	\$5,898	\$4,955	\$642	\$132	\$1	\$49	\$36	\$21	\$1	\$3	\$8	\$1	\$4	\$3	\$0	\$1	\$0	\$41
53	\$000	Customer	Total Customer (Commitment & Billing)	\$257,913	\$185,235	\$36,801	\$9,846	\$160	\$5,468	\$4,426	\$3,326	\$93	\$397	\$1,195	\$77	\$475	\$145	\$5	\$61	\$167	\$10,034
54																					
55																					
56			Total Revenue @ Full MC (\$000)	\$1,162,830	\$597,598	\$73,906	\$49,946	\$356	\$33,753	\$47,019	\$57,960	\$1,524	\$12,105	\$60,742	\$5,927	\$32,928	\$30,904	\$2,062	\$50,264	\$73,367	\$32,469

5 Year MC

PacifiCorp  
Oregon Marginal Cost Study  
5 Year Marginal Costs  
December 2023 Dollars

Line	Calculation Component	Class	Units Description / Function	Total	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48				Irrg - Sch 41	
					(sec)	0-15 kW (sec)	15+ kW (sec)	Primary (pri)	0-50 kW (sec)	51-100 kW (sec)	100+ kW (sec)	Primary (pri)	0-300 kW (sec)	300+ kW (sec)	Primary (pri)	1 - 4 MW (sec)	1 - 4 MW (pri)	> 4 MW (sec)	> 4 MW (pri)	Trn (trn)	(sec)
1	Units	Demand	Peak MW @ Input-System		1,152	92	100	0	73	108	138	4	30	148	15	75	70	5	125	186	38
2	Units	Energy	Annual MWh @ Input	6,082,593	588,687	635,298	3,533	472,029	718,357	934,868	25,303	206,473	1,070,906	104,635	547,595	531,645	41,798	1,024,837	1,599,365	284,558	
3	Units	Customer	Average	535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	4,356	
4	Units	Customer	Annual	535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	7,997	
7	S/Unit	Demand	Generation (\$/System Peak kW)	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50	\$93.50
8	S/Unit	Energy	Generation Energy @ Input (\$/kWh)	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284	\$0.03284
9	S/Unit	Customer	Dist-Service Drop (\$/Customer)	\$75.76	\$102.46	\$198.46	\$0.00	\$205.20	\$214.31	\$415.31	\$0.00	\$415.15	\$799.21	\$0.00	\$2,733.92	\$0.00	\$2,733.92	\$0.00	\$0.00	\$0.00	\$0.00
10	S/Unit	Customer	Meters (\$/Customer)	\$23.21	\$24.69	\$28.37	\$1,164.18	\$31.92	\$34.16	\$177.40	\$1,164.18	\$177.96	\$178.19	\$1,164.18	\$215.74	\$1,164.18	\$215.74	\$1,164.18	\$1,889.86	\$34.18	
11	S/Unit	Customer	Meter Reading (\$/Customer)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	
12	S/Unit	Customer	Billing & Collections (\$/Customer)	\$25.10	\$30.35	\$30.35	\$30.35	\$35.21	\$35.21	\$35.21	\$35.21	\$35.21	\$35.21	\$35.21	\$290.78	\$290.78	\$290.78	\$290.78	\$290.78	\$290.78	
13	S/Unit	Customer	Uncollectables (\$/Customer)	\$9.64	\$2.49	\$2.49	\$2.49	\$25.02	\$25.02	\$25.02	\$25.02	\$148.58	\$148.58	\$148.58	\$696.73	\$696.73	\$696.73	\$696.73	\$696.73	\$696.73	
14	S/Unit	Customer	Customer Service / Other (\$/Customer)	\$9.26	\$9.19	\$9.19	\$9.19	\$10.20	\$10.20	\$10.20	\$10.20	\$14.74	\$14.74	\$14.74	\$44.26	\$44.26	\$44.26	\$44.26	\$44.26	\$44.26	
17	(\$000)	Demand	Total Demand	\$220,497	\$107,745	\$8,573	\$9,353	\$44	\$6,809	\$10,097	\$12,885	\$345	\$2,790	\$13,880	\$1,428	\$6,992	\$6,506	\$475	\$11,681	\$17,372	\$3,524
18	(\$000)	Energy	Total Energy	\$488,412	\$199,752	\$19,332	\$20,863	\$116	\$15,501	\$23,591	\$30,701	\$831	\$6,781	\$35,169	\$3,436	\$17,983	\$17,459	\$1,373	\$33,656	\$52,523	\$9,345
19	(\$000)	Customer	Total Customer (Billing)	\$98,436	\$76,495	\$11,810	\$3,874	\$139	\$1,482	\$1,136	\$1,334	\$85	\$169	\$624	\$72	\$366	\$134	\$4	\$61	\$167	\$483
20			Total Revenue @ Full MC (\$000)	\$807,346	\$383,992	\$39,716	\$34,090	\$299	\$23,792	\$34,824	\$44,920	\$1,261	\$9,739	\$49,673	\$4,937	\$25,341	\$24,099	\$1,852	\$45,398	\$70,063	\$13,352

1 Year MC

PacifiCorp  
Oregon Marginal Cost Study  
1 Year Marginal Costs  
December 2023 Dollars

Line	Calculation Component	Class	Units Description / Function	Total	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48				Irrg - Sch 41	
					(sec)	0-15 kW (sec)	15+ kW (sec)	Primary (pri)	0-50 kW (sec)	51-100 kW (sec)	100+ kW (sec)	Primary (pri)	0-300 kW (sec)	300+ kW (sec)	Primary (pri)	1 - 4 MW (sec)	1 - 4 MW (pri)	> 4 MW (sec)	> 4 MW (pri)	Tm (tn)	(sec)
1	Units	Energy	Annual MWh @ Input		6,082,593	588,687	635,298	3,533	472,029	718,357	934,868	25,303	206,473	1,070,906	104,635	547,595	531,645	41,798	1,024,837	1,599,365	284,558
2	Units	Customer	Average		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	4,356
3	Units	Customer	Annual		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	7,997
4																					
5																					
6	\$/Unit	Energy	Generation Energy @ Input (\$/kWh)		\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196	\$0.03196
7	\$/Unit	Customer	Dist-Service Drop (\$/Customer)		75.759615	\$102.46	\$198.46	\$0.00	\$205.20	\$214.31	\$415.31	\$0.00	\$415.15	\$799.21	\$0.00	\$2,733.92	\$0.00	\$2,733.92	\$0.00	\$0.00	\$0.00
8	\$/Unit	Customer	Meters (\$/Customer)		\$23.21	\$24.69	\$28.37	\$1,164.18	\$31.92	\$34.16	\$177.40	\$1,164.18	\$177.96	\$178.19	\$1,164.18	\$215.74	\$1,164.18	\$215.74	\$1,164.18	\$19,889.86	\$34.18
9	\$/Unit	Customer	Meter Reading (\$/Customer)		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$177.40	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
10	\$/Unit	Customer	Billing & Collections (\$/Customer)		\$25.10	\$30.35	\$30.35	\$30.35	\$35.21	\$35.21	\$35.21	\$35.21	\$35.21	\$35.21	\$35.21	\$290.78	\$290.78	\$290.78	\$290.78	\$290.78	\$30.33
11	\$/Unit	Customer	Uncollectables (\$/Customer)		\$9.64	\$2.49	\$2.49	\$2.49	\$25.02	\$25.02	\$25.02	\$25.02	\$148.58	\$148.58	\$148.58	\$696.73	\$696.73	\$696.73	\$696.73	\$696.73	\$8.29
12	\$/Unit	Customer	Customer Service / Other (\$/Customer)		\$9.26	\$9.19	\$9.19	\$9.19	\$10.20	\$10.20	\$10.20	\$10.20	\$14.74	\$14.74	\$14.74	\$44.26	\$44.26	\$44.26	\$44.26	\$44.26	\$9.40
13																					
14																					
15	(\$000)	Energy	Total Energy	\$475,384	\$194,424	\$18,817	\$20,307	\$113	\$15,088	\$22,962	\$29,882	\$809	\$6,600	\$34,230	\$3,345	\$17,503	\$16,993	\$1,336	\$32,758	\$51,122	\$9,096
16	(\$000)	Customer	Total Customer (Billing)	\$98,436	\$76,495	\$11,810	\$3,874	\$139	\$1,482	\$1,136	\$1,334	\$85	\$169	\$624	\$72	\$366	\$134	\$4	\$61	\$167	\$483
17			Total Revenue @ Full MC (\$000)	\$573,820	\$270,919	\$30,627	\$24,180	\$252	\$16,570	\$24,098	\$31,216	\$894	\$6,768	\$34,855	\$3,417	\$17,870	\$17,127	\$1,340	\$32,819	\$51,289	\$9,578



Energy

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

	(A)	(B) =(A)/12	(C)	(D) =(C)/12	(E) =(D)-(B)	(F)	(G)	(H)	(I)	(J) =(G)+(I)	(K)	(L)	(M)	(N) =(F)+(J)+(M)	(O)	(P) =(N)*(O)
Calendar Year (12 Mo Ended Dec)	SCCT Fixed Costs (\$/kW-yr)	SCCT Fixed Costs (\$/kW-mo)	CCCT Fixed Costs (\$/kW-yr)	CCCT Fixed Costs (\$/kW-mo)	Capitalized Energy Cost (\$/kW-mo)	Capitalized Energy Cost 70.5% CF (\$/MWh)	Purchase Cost (\$/MWh)	Updated Gas Price (\$/MMBtu)	CCCT Energy Costs 6,790 Btu/kWh (\$/MWh)	Variable Avoided Energy Cost (\$/MWh)	REC Price (\$/REC)	Oregon RPS %	Cost of RPS Compliance (\$/MWh)	Total Avoided Energy Cost (\$/MWh)	Present Value Factors @ 7.21%	Present Value of Energy (Mills/kWh)
2023	93.53	7.79	171.00	14.25	6.46	12.54	0.00	2.86	19.42	19.42	0.00	20%	0.00	31.96	1.0000	31.96
2024	95.66	7.97	174.89	14.57	6.60	12.83	0.00	2.88	19.56	19.56	0.00	20%	0.00	32.38	0.9327	30.21
2025	97.84	8.15	178.86	14.91	6.75	13.12	0.00	3.16	21.46	21.46	0.00	20%	0.00	34.58	0.8700	30.08
2026	100.07	8.34	182.91	15.24	6.90	13.41	0.00	3.33	22.61	22.61	0.00	20%	0.00	36.02	0.8115	29.23
2027	102.36	8.53	187.11	15.59	7.06	13.72	0.00	3.49	23.70	23.70	0.00	27%	0.00	37.42	0.7569	28.32
2028	104.70	8.73	191.40	15.95	7.23	14.04	0.00	3.71	25.19	25.19	0.00	27%	0.00	39.23	0.7060	27.70
2029	107.09	8.92	195.77	16.31	7.39	14.36	0.00	4.04	27.43	27.43	0.00	27%	0.00	41.79	0.6585	27.52
2030	109.53	9.13	200.23	16.69	7.56	14.69	0.00	4.19	28.45	28.45	0.00	27%	0.00	43.14	0.6142	26.49
2031	112.03	9.34	204.79	17.07	7.73	15.02	0.00	4.33	29.40	29.40	0.00	27%	0.00	44.42	0.5729	25.45
2032	114.58	9.55	209.45	17.45	7.91	15.36	0.00	4.38	29.74	29.74	0.00	35%	0.00	45.10	0.5344	24.10
2033	117.19	9.77	214.20	17.85	8.08	15.71	0.00	4.58	31.10	31.10	0.00	35%	0.00	46.81	0.4985	23.33
2034	119.86	9.99	219.05	18.25	8.27	16.06	0.00	4.61	31.30	31.30	0.00	35%	0.00	47.36	0.4650	22.02
2035	122.60	10.22	224.06	18.67	8.46	16.43	0.00	4.63	31.44	31.44	0.00	35%	0.00	47.87	0.4337	20.76
2036	125.39	10.45	229.19	19.10	8.65	16.81	0.00	4.70	31.91	31.91	0.00	35%	0.00	48.72	0.4045	19.71
2037	128.25	10.69	234.43	19.54	8.85	17.19	0.00	4.83	32.80	32.80	0.00	45%	0.00	49.99	0.3773	18.86
2038	131.17	10.93	239.76	19.98	9.05	17.58	0.00	4.93	33.47	33.47	0.00	45%	0.00	51.06	0.3519	17.97
2039	134.17	11.18	245.21	20.43	9.25	17.98	0.00	5.19	35.24	35.24	0.00	45%	0.00	53.22	0.3282	17.47
2040	137.23	11.44	250.77	20.90	9.46	18.38	0.00	5.43	36.87	36.87	0.00	45%	0.00	55.25	0.3061	16.91
2041	140.36	11.70	256.52	21.38	9.68	18.81	0.00	5.55	37.71	37.71	0.00	45%	0.00	56.52	0.2855	16.14
2042	143.56	11.96	262.38	21.87	9.90	19.24	0.00	5.68	38.57	38.57	0.00	50%	0.00	57.81	0.2663	15.40

Mills/kWh  
31.96

2023 (1 Year)

2023 - 2027 (5 Year, Short Run)

Sum of PV Costs @ 7.21% 149.81  
Annual Cost of Energy @ 21.92% 32.84

2023 - 2032 (10 Year, Medium Run)

Sum of PV Costs @ 7.21% 281.07  
Annual Cost of Energy @ 12.24% 34.40

2023 - 2042 (20 Year, Long Run)

Sum of PV Costs @ 7.21% 469.63  
Annual Cost of Energy @ 7.52% 35.32

Capacity

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

	(A)	(B)	(C) (A) x (B)	(D) (A) / 0.705 / 8,760	(E) (B) * (D)
Calendar Year (12 Mo Ended Dec)	Projected Capacity \$/kW	Present Value Factors @ 7.21%	PV of Capacity \$/kW	Capacity Mills/kWh	PV of Capacity Mills/kWh
2023	\$93.53	1.0000	93.53	15.14	15.14
2024	\$95.66	0.9327	89.22	15.49	14.45
2025	\$97.84	0.8700	85.12	15.84	13.78
2026	\$100.07	0.8115	81.21	16.20	13.15
2027	\$102.36	0.7569	77.48	16.57	12.54
2028	\$104.70	0.7060	73.92	16.95	11.97
2029	\$107.09	0.6585	70.52	17.34	11.42
2030	\$109.53	0.6142	67.27	17.74	10.90
2031	\$112.03	0.5729	64.18	18.14	10.39
2032	\$114.58	0.5344	61.23	18.55	9.91
2033	\$117.19	0.4985	58.42	18.98	9.46
2034	\$119.86	0.4650	55.73	19.41	9.03
2035	\$122.60	0.4337	53.17	19.85	8.61
2036	\$125.39	0.4045	50.72	20.30	8.21
2037	\$128.25	0.3773	48.39	20.77	7.84
2038	\$131.17	0.3519	46.16	21.24	7.47
2039	\$134.17	0.3282	44.03	21.73	7.13
2040	\$137.23	0.3061	42.01	22.22	6.80
2041	\$140.36	0.2855	40.07	22.73	6.49
2042	\$143.56	0.2663	38.23	23.25	6.19
			\$ / kW		Mills / kWh
<u>2023 (1 Year)</u>			93.53		15.14
<u>2023 - 2027 (5 Year, Short Run)</u>					
		Sum of PV Costs @ 7.21%	426.56		69.06
		Annual Cost of Capacity @ 21.92%	93.50		15.14
<u>2023 - 2032 (10 Year, Medium Run)</u>					
		Sum of PV Costs @ 7.21%	763.68		123.65
		Annual Cost of Capacity @ 12.24%	93.47		15.13
<u>2023 - 2042 (20 Year, Long Run)</u>					
		Sum of PV Costs @ 7.21%	1,240.61		200.88
		Annual Cost of Capacity @ 7.52%	93.29		15.11

Avoided Costs

PacifiCorp  
Filed Marginal Generation Costs

Calendar Year	12 Months Ended December			12 Months Ended December		
	Avoided Simple Cycle CT Fixed Costs (\$/kW-yr)	Avoided Combined Cycle CT Fixed Costs (\$/kW-yr)	Gas Price (\$/MMBtu)	Avoided Firm Capacity Costs (\$/kW-yr)	Combined Cycle CT Fixed Cost (\$/kW-yr)	Gas Price (\$/MMBtu)
2023	93.53	171.00	2.86	93.53	171.00	2.86
2024	95.66	174.89	2.88	95.66	174.89	2.88
2025	97.84	178.86	3.16	97.84	178.86	3.16
2026	100.07	182.91	3.33	100.07	182.91	3.33
2027	102.36	187.11	3.49	102.36	187.11	3.49
2028	104.70	191.40	3.71	104.70	191.40	3.71
2029	107.09	195.77	4.04	107.09	195.77	4.04
2030	109.53	200.23	4.19	109.53	200.23	4.19
2031	112.03	204.79	4.33	112.03	204.79	4.33
2032	114.58	209.45	4.38	114.58	209.45	4.38
2033	117.19	214.20	4.58	117.19	214.20	4.58
2034	119.86	219.05	4.61	119.86	219.05	4.61
2035	122.60	224.06	4.63	122.60	224.06	4.63
2036	125.39	229.19	4.70	125.39	229.19	4.70
2037	128.25	234.43	4.83	128.25	234.43	4.83
2038	131.17	239.76	4.93	131.17	239.76	4.93
2039	134.17	245.21	5.19	134.17	245.21	5.19
2040	137.23	250.77	5.43	137.23	250.77	5.43
2041	140.36	256.52	5.55	140.36	256.52	5.55
2042	143.56	262.38	5.68	143.56	262.38	5.68

CCCT Capacity Factor 70.5%  
CCCT Heat Rate (Btu/kWh) 6,790

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

Transm1

PacifiCorp  
Oregon Marginal Cost Study  
Marginal Transmission Investment and O&M Expenses  
2023 Dollars

Line	Description	Calculation	Total	Demand Related	Energy Related
1	2022 Forecast Growth Related Investments (\$000)		\$44,326	\$44,326	\$0
2	2023 Forecast Growth Related Investments (\$000)		\$46,643	\$46,643	\$0
3	2024 Forecast Growth Related Investments (\$000)		\$19,155	\$19,155	\$0
4	2025 Forecast Growth Related Investments (\$000)		\$33,140	\$33,140	\$0
5	2026 Forecast Growth Related Investments (\$000)		\$15,438	\$15,438	\$0
6					
7	2022 to 2026 Forecast Growth Related Investments (\$000)		\$158,702	\$158,702	\$0
8					
9	Capacity Addition MW from 2022-2026		2,879		
10					
11	Marginal Investment (\$/KW)	7 / 9	\$55.13	\$55.13	\$0.00
12					
13	Annualized Investment (\$/KW)	11 x 6.16%	\$3.40	\$3.40	\$0.00
14	Admin. & General Factor (\$/KW)	11 x 0.60%	\$0.33	\$0.33	\$0.00
15	Annual O&M Expenses (\$/KW)	11 x 1.176%	\$0.65	\$0.65	\$0.00
16					
17	Annualized Marginal Cost (\$/KW)	13 + 14 + 15	\$4.38	\$4.38	\$0.00
18					
19	Marginal Cost of Energy-Related Transmission (\$/KWh)	17 / 8760 hrs / 77.45% LF			\$0.00000

Transm2

PacifiCorp  
Oregon Marginal Cost Study  
2022-2026 Forecasted Transmission  
December 2023 Dollars (000s)

Line	Description	Calculation	Forecast				
			2022	2023	2024	2025	2026
1	Bulk Power Lines (grid)		\$0	\$0	\$0	\$0	\$0
2	Escalation Factor		<u>1.060</u>	<u>1.060</u>	<u>1.060</u>	<u>1.060</u>	<u>1.060</u>
3	Adjusted Bulk Power Lines (grid)	1 x 2	\$0	\$0	\$0	\$0	\$0
4							
5	Growth Related Major Projects (local)		\$41,799	\$43,984	\$18,063	\$31,251	\$14,558
6	Escalation Factor		<u>1.0605</u>	<u>1.0605</u>	<u>1.0605</u>	<u>1.0605</u>	<u>1.0605</u>
7	Adjusted Growth Related Major Projects (local)	5 x 6	\$44,326	\$46,643	\$19,155	\$33,140	\$15,438
8							
9	Total Growth Related Investments - Demand	3 x 29.96% + 7	\$44,326	\$46,643	\$19,155	\$33,140	\$15,438
10	Total Growth Related Investments - Energy	3 x 70.04%	\$0	\$0	\$0	\$0	\$0
11	Total Marginal Transmission Investment	3 + 7	\$44,326	\$46,643	\$19,155	\$33,140	\$15,438

Footnotes:

Line 1 & 5 Bulk power line & growth related projects data provided in 2021 dollars for each year

Line 9 Demand Portion of Transmission = PV of Long Run Capacity Costs / PV of Total Long Run Costs = 200.88 / (200.88+469.63) = 29.96%

Line 10 Energy Portion of Transmission = PV of Long Run Energy Costs / PV of Total Long Run Costs = 469.63 / (200.88+469.63) = 70.04%

<u>Index</u>		Escalation Factor <u>2021 - 2023</u>
<u>2021</u>	<u>2023</u>	
1.0406	1.1035	1.0605

Tran OM

PacifiCorp  
Transmission O & M Expenses  
(Dollars in 000's)

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K) =AVERAGE of (A) thru (J)
Line	Description	Calculation	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
1	Transmission O&M Exp.		204,716	206,484	198,670	211,984	215,664	203,261	204,806	206,506	218,367	210,892	
2	Wheeling		138,235	142,125	137,182	151,336	148,425	130,789	134,473	135,022	145,825	141,188	
3	Net Transmission O&M	1-2	66,481	64,359	61,488	60,648	67,239	72,472	70,333	71,484	72,541	69,703	
4	Transmission Plant		4,500,418	4,724,914	5,231,106	5,387,871	5,910,756	6,051,720	6,222,286	6,353,045	6,478,620	7,630,241	
5	Tran. O&M Loading	3/4	1.477%	1.362%	1.175%	1.126%	1.138%	1.198%	1.130%	1.125%	1.120%	0.914%	1.176%

Source:  
PacifiCorp FERC Form 1  
(1) page 321, line 112  
(2) page 321, line 96  
(4) page 206-07, line 58

TranLF

PacifiCorp  
System Load Factor

Line No.	Month	Total Monthly Energy	Associated Losses	(D) (B)-(C)	MW (E)
	(A)	(B)	(C)		
1	January	5,521,779	357,238	5,164,541	8,327
2	February	5,031,397	372,019	4,659,378	8,221
3	March	5,200,628	473,753	4,726,875	7,658
4	April	4,483,384	80,680	4,402,704	6,924
5	May	4,781,604	321,598	4,460,006	8,750
6	June	5,111,972	470,864	4,641,108	9,451
7	July	5,880,577	313,386	5,567,191	10,476
8	August	6,044,999	402,100	5,642,899	10,546
9	September	5,023,885	274,292	4,749,593	9,618
10	October	5,304,644	732,752	4,571,892	7,776
11	November	5,467,552	673,488	4,794,064	7,885
12	December	5,879,969	509,753	5,370,216	8,274
13		63,732,390	4,981,923	58,750,467	
14					
15				Average Monthly MW	8,659
16				Load Factor	77.45%

Source: FERC Form 1, December 31, 2020  
Page 401b

DistSub1

PacifiCorp  
Oregon Marginal Cost Study  
Distribution Substation Costs / kW  
2023 Dollars

Line	Description	Calculation	Value
1	Incremental Substation Cost (\$/kVA)		\$325.57
2	Power Factor		0.95
3	Substation Utilization Factor		53.11%
4	Incremental Substation Cost (\$/kW)	1/2*3	\$182.00
5			
6	Annual Distribution Carrying Charge		6.97%
7			
8	Substation Marginal Cost (\$/kW)	4*6	\$12.69



DistSub2

PacifiCorp  
Marginal Cost Study  
Substation Investment

(A)	(B)	(C)	(D)	(E)	(F) =(E)/(D)
In Service Year	Substation Capacity Project	State	Capacity Increase (MVA)	Installed Cost (000)	Installed Cost/MVA (000)
2022	Conser Road	OR	30.0	\$11,054	\$368.48
2022	Flint	WA	30.0	\$20,711	\$690.36
2022	Jefferson	OR	7.5	\$1,943	\$259.02
2022	Shevlin Park	OR	25.0	\$4,446	\$177.85
2022	Fraley	OR	0.5	\$429	\$857.53
2023	Dorris	OR	5.0	\$1,461	\$292.15
2023	Ahtanum	WA	25.0	\$10,213	\$408.52
2024	Mill City	OR	25.0	\$3,667	\$146.69
2024	Tieton	WA	25.0	\$3,021	\$120.85
2025	Empire	OR	25.0	\$4,692	\$187.66
2025	Fort Jones	CA	7.0	\$1,441	\$205.86
2025	Banfield	OR	25.0	\$8,241	\$329.65
2026	Glendale	OR	12.5	\$2,795	\$223.59
2026	Wake Robin	OR	30.0	\$9,545	\$318.18
Western States Total			272.5	\$83,659	\$307.01

2021 Incremental Substation Cost (\$/KVA) \$307.01

<u>Index</u>		Escalation Factor <u>2021 - 2023</u>
<u>2021</u>	<u>2023</u>	
1.0406	1.1035	1.0605

2023 Incremental Substation Cost (\$/KVA) \$325.57

PacifiCorp  
 Oregon Marginal Cost Study  
 Hypothetical Circuit Study Results  
 Annual Demand and Commitment Costs  
 December 2023 Dollars

Line	Load Class		(A) (B) (C) (D)				(E) (F) (G) (H)			
			Demand				Commitment			
			Investment \$ / kW <sup>1</sup>		Annual \$ / kW <sup>1</sup>		Investment \$ / Customer		Annual \$ / Customer	
Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor			
				(A) x 6.97%	(B) x 6.97%			(E) x 6.97%	(F) x 6.97%	
1	Res - Schedule 4	(sec)	\$169.36	\$260.30	\$11.80	\$18.14	\$778.54	\$386.55	\$54.26	\$26.94
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	\$258.19	\$345.16	\$18.00	\$24.06	\$1,228.79	\$610.10	\$85.65	\$42.52
5	15+ kW	(sec)	\$258.19	\$345.16	\$18.00	\$24.06	\$1,228.79	\$610.10	\$85.65	\$42.52
6	Primary	(pri)	\$258.19	\$345.16	\$18.00	\$24.06	\$1,228.79	\$610.10	\$85.65	\$42.52
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	\$171.22	\$260.40	\$11.93	\$18.15	\$784.18	\$389.35	\$54.66	\$27.14
10	51-100 kW	(sec)	\$171.22	\$260.40	\$11.93	\$18.15	\$784.18	\$389.35	\$54.66	\$27.14
11	100 + kW	(sec)	\$171.22	\$260.40	\$11.93	\$18.15	\$784.18	\$389.35	\$54.66	\$27.14
12	Primary	(pri)	\$171.22	\$260.40	\$11.93	\$18.15	\$784.18	\$389.35	\$54.66	\$27.14
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	\$123.91	\$214.65	\$8.64	\$14.96	\$543.14	\$269.67	\$37.86	\$18.80
16	300+ kW	(sec)	\$123.91	\$214.65	\$8.64	\$14.96	\$543.14	\$269.67	\$37.86	\$18.80
17	Primary	(pri)	\$123.91	\$214.65	\$8.64	\$14.96	\$543.14	\$269.67	\$37.86	\$18.80
18										
19	LPS - Schedule 48									
20	1 - 4 MW	(sec)	\$264.47	\$344.11	\$18.43	\$23.98	\$1,244.53	\$617.91	\$86.74	\$43.07
21	1 - 4 MW	(pri)	\$264.47	\$344.11	\$18.43	\$23.98	\$1,244.53	\$617.91	\$86.74	\$43.07
22	> 4 MW	(sec)	\$8.45	\$16.43	\$0.59	\$1.15	\$0.00	\$0.00	\$0.00	\$0.00
23	> 4 MW	(pri)	\$9.46	\$18.39	\$0.66	\$1.28	\$0.00	\$0.00	\$0.00	\$0.00
24										
25	Irrigation - Schedule 41	(sec)	\$500.45	\$592.31	\$34.88	\$41.28	\$2,492.46	\$1,237.52	\$173.72	\$86.26

Footnote:

<sup>1</sup>\$ / kW are in terms of Distribution kW.

PacifiCorp  
Oregon Marginal Cost Study  
Calculation of Escalation Factors  
Poles and Conductor  
Three Phase Costs as Demand

Line	Load Class		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Demand		Commitment		2023 Demand		2023 Commitment	
			Poles	Conductor	Poles	Conductor	Poles (D) x 1.0605	Conductor (C) x 1.0605	Poles (B) x 1.0605	Conductor (A) x 1.0605
1	Res - Schedule 4	(sec)	\$159.69	\$245.45	\$734.13	\$364.50	\$169.36	\$260.30	\$778.54	\$386.55
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	\$243.46	\$325.47	\$1,158.69	\$575.29	\$258.19	\$345.16	\$1,228.79	\$610.10
5	15+ kW	(sec)	\$243.46	\$325.47	\$1,158.69	\$575.29	\$258.19	\$345.16	\$1,228.79	\$610.10
6	Primary	(pri)	\$243.46	\$325.47	\$1,158.69	\$575.29	\$258.19	\$345.16	\$1,228.79	\$610.10
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	\$161.46	\$245.54	\$739.44	\$367.14	\$171.22	\$260.40	\$784.18	\$389.35
10	51-100 kW	(sec)	\$161.46	\$245.54	\$739.44	\$367.14	\$171.22	\$260.40	\$784.18	\$389.35
11	100 + kW	(sec)	\$161.46	\$245.54	\$739.44	\$367.14	\$171.22	\$260.40	\$784.18	\$389.35
12	Primary	(pri)	\$161.46	\$245.54	\$739.44	\$367.14	\$171.22	\$260.40	\$784.18	\$389.35
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	\$116.84	\$202.41	\$512.16	\$254.29	\$123.91	\$214.65	\$543.14	\$269.67
16	300+ kW	(sec)	\$116.84	\$202.41	\$512.16	\$254.29	\$123.91	\$214.65	\$543.14	\$269.67
17	Primary	(pri)	\$116.84	\$202.41	\$512.16	\$254.29	\$123.91	\$214.65	\$543.14	\$269.67
18										
19	LPS - Schedule 48									
20	1 - 4 MW	(sec)	\$249.38	\$324.48	\$1,173.53	\$582.66	\$264.47	\$344.11	\$1,244.53	\$617.91
21	1 - 4 MW	(pri)	\$249.38	\$324.48	\$1,173.53	\$582.66	\$264.47	\$344.11	\$1,244.53	\$617.91
22	> 4 MW	(sec)	\$7.97	\$15.49	\$0.00	\$0.00	\$8.45	\$16.43	\$0.00	\$0.00
23	> 4 MW	(pri)	\$8.92	\$17.34	\$0.00	\$0.00	\$9.46	\$18.39	\$0.00	\$0.00
24										
25	Irrigation - Schedule 41	(sec)	\$471.90	\$558.52	\$2,350.27	\$1,166.92	\$500.45	\$592.31	\$2,492.46	\$1,237.52

Index		Escalation Factor
2021	2023	2021 - 2023
1.0406	1.1035	1.0605

Footnote:  
Pole and conductor costs from Distribution Circuit Model.

PC 3

PacifiCorp  
Oregon Marginal Cost Study  
Circuit Distribution Model  
Inputs & Calculations

Line	(A)	(B)	(C)	(D)	(E)	(F)
	Annual	Number	Average	Distribution	Average	Percent
	MWh	of	MWh per	Peak	kW per	Single
		Customers	Customer	MW	customer	Phase
Class			(A) / (B)		(D)/(B) * 1,000	
5 Res - Schedule 4 (sec)	5,755,783	519,723	11.07	1,266	2.43	100.00%
6 GS - Schedule 23 - 0-15 kW (sec)	567,191	70,227	8.08	84	1.19	80.83%
7 GS - Schedule 23 - 15+ kW (sec)	612,100	14,495	42.23	93	6.44	54.35%
8 GS - Schedule 23 - Primary (pri)	3,443	116	29.75	0	2.85	-
9 GS - Schedule 28 - 0-50 kW (sec)	442,735	4,736	93.48	67	14.08	28.88%
10 GS - Schedule 28 - 51-100 kW (sec)	673,777	3,501	192.48	98	28.02	12.69%
11 GS - Schedule 28 - 100+ kW (sec)	876,851	1,977	443.48	125	63.35	1.56%
12 GS - Schedule 28 - Primary (pri)	24,061	68	355.22	3	44.27	-
13 GS - Schedule 30 - 0-300 kW (sec)	186,365	217	859.44	28	127.91	0.47%
14 GS - Schedule 30 - 300+ kW (sec)	966,612	539	1,792.03	137	253.22	-
15 GS - Schedule 30 - Primary (pri)	95,500	53	1,789.23	13	251.41	-
16 Irrigation - Sch 41	237,458	6,572	36.13	62	9.38	15.50%
17 LPS - Schedule 48 - 1 - 4 MW (sec)	503,599	93	5,441.21	70	761.13	-
18 LPS - Schedule 48 - 1 - 4 MW (pri)	510,192	61	8,328.53	66	1,080.41	-
19 LPS - Schedule 48 - > 4 MW (sec)	38,440	1	38,017.58	5	4,763.92	-
20 LPS - Schedule 48 - > 4 MW (pri)	983,483	28	34,895.90	120	4,256.39	-
21 Total	12,477,589	622,407		2,237		

Customer Distribution on the Hypothetical Circuit Branch

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Class	1	2	3	4	5	6	7	Branch Total
28 Res - Schedule 4 (sec)	0.38%	0.38%	0.38%	1.83%	1.83%	1.83%	93.37%	100.00%
29 GS - Schedule 23 - 0-15 kW (sec)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
30 GS - Schedule 23 - 15+ kW (sec)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
31 GS - Schedule 23 - Primary (pri)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
32 GS - Schedule 28 - 0-50 kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
33 GS - Schedule 28 - 51-100 kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
34 GS - Schedule 28 - 100+ kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
35 GS - Schedule 28 - Primary (pri)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
36 GS - Schedule 30 - 0-300 kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
37 GS - Schedule 30 - 300+ kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
38 GS - Schedule 30 - Primary (pri)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
39 Irrigation - Sch 41	1.10%	1.10%	1.10%	7.97%	7.97%	7.97%	72.78%	100.00%
40 LPS - Schedule 48 - 1 - 4 MW (sec)	1.03%	1.03%	1.03%	1.37%	1.37%	1.37%	92.82%	100.00%
41 LPS - Schedule 48 - 1 - 4 MW (pri)	1.03%	1.03%	1.03%	1.37%	1.37%	1.37%	92.82%	100.00%
42 LPS - Schedule 48 - > 4 MW (sec)								
43 LPS - Schedule 48 - > 4 MW (pri)								

Large Customers are on dedicated circuits and are not included here  
Large Customers are on dedicated circuits and are not included here

System property records & engineering information

47 Number of pole feet in Oregon	74,711,073
48 Number of pole miles in Oregon	14,150
49 Number of trench feet in Oregon	28,496,127
50 Number of trench miles in Oregon	5,397
51 Total miles in Oregon	19,547
52 Number of circuits in Oregon	530
53 Number of poles in Oregon	377,374
54 Poles per mile	26.67
55 Customers per mile	31.84
56 MWh per customer	20.05
57 MWh per circuit	23,543
58 Branches per circuit	7
59 Miles per circuit	36.88
60 Miles per branch	5.27
61 Single Phase Miles per Branch <sup>1</sup>	1.84

<sup>1</sup>A 12 KV circuit 12 miles long has approx. 3 miles of single phase, which is approx. 25 percent of circuit distance, so applying 25% to the Miles per Circuit and dividing this amount by the 5 outer branches gives the Single Phase Miles per Branch.

PacifiCorp  
Oregon Circuit Model Study  
Customer Distribution on the Hypothetical Circuit Branch

Line	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		1	2	3	4	5	6	7	Total
1	Res - Schedule 4 (sec)	0.38%	0.38%	0.38%	1.83%	1.83%	1.83%	93.37%	100.00%
2	GS - Schedule 23 - 0-15 kW (sec)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
3	GS - Schedule 23 - 15+ kW (sec)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
4	GS - Schedule 23 - Primary (pri)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
5	GS - Schedule 28 - 0-50 kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
6	GS - Schedule 28 - 51-100 kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
7	GS - Schedule 28 - 100 + kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
8	GS - Schedule 28 - Primary (pri)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
9	GS - Schedule 30 - 0-300 kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
10	GS - Schedule 30 - 300+ kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
11	GS - Schedule 30 - Primary (pri)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
12	Irrigation - Sch 41	1.10%	1.10%	1.10%	7.97%	7.97%	7.97%	72.78%	100.00%
13	LPS - Schedule 48 - 1 - 4 MW (sec)	1.03%	1.03%	1.03%	1.37%	1.37%	1.37%	92.82%	100.00%
14	LPS - Schedule 48 - 1 - 4 MW (pri)	1.03%	1.03%	1.03%	1.37%	1.37%	1.37%	92.82%	100.00%
15	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
16	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-

Except where customers own their own transformers.

PacifiCorp  
Oregon Circuit Model Study  
Average Customers by Hypothetical Circuit Branch

Line	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
1	Hypothetical Circuit Branch								
2	Class	1	2	3	4	5	6	7	Total
3	Res - Schedule 4 (sec)	3.68	3.68	3.68	17.98	17.98	17.98	915.63	980.61
4	GS - Schedule 23 - 0-15 kW (sec)	0.97	0.97	0.97	3.54	3.54	3.54	118.99	132.50
5	GS - Schedule 23 - 15+ kW (sec)	0.20	0.20	0.20	0.73	0.73	0.73	24.56	27.35
6	GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.01	0.01	0.01	0.20	0.22
7	GS - Schedule 28 - 0-50 kW (sec)	0.04	0.04	0.04	0.14	0.14	0.14	8.41	8.94
8	GS - Schedule 28 - 51-100 kW (sec)	0.03	0.03	0.03	0.10	0.10	0.10	6.21	6.60
9	GS - Schedule 28 - 100+ kW (sec)	0.02	0.02	0.02	0.06	0.06	0.06	3.51	3.73
10	GS - Schedule 28 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.13
11	GS - Schedule 30 - 0-300 kW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.39	0.41
12	GS - Schedule 30 - 300+ kW (sec)	0.00	0.00	0.00	0.01	0.01	0.01	0.98	1.02
13	GS - Schedule 30 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.10
14	Irrigation - Sch 41	0.14	0.14	0.14	0.99	0.99	0.99	9.02	12.40
15	LPS - Schedule 48 - 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.17
16	LPS - Schedule 48 - 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.12
17	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
18	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	5.08	5.08	5.08	23.55	23.55	23.55	1,088.39	1,174.30
20									
21	Source - 'Circuit Distribution Model Inputs & Calculations' (PC 3)								
22	Source - 'Customer Distribution on the Hypothetical Circuit Branch' (PC 4)								
23	Customers multiplied by Customer Distribution on the Hypothetical Circuit Branch divided by circuits in the state.								
24	For Example 3.68 is 519,723 Residential Customers X .376% customers on Branch 1 divided by 530 circuits.								
25									
26	Percent of Customers								
27	Res - Schedule 4 (sec)	72.45%	72.45%	72.45%	76.33%	76.33%	76.33%	84.13%	83.51%
28	GS - Schedule 23 - 0-15 kW (sec)	19.05%	19.05%	19.05%	15.01%	15.01%	15.01%	10.93%	11.28%
29	GS - Schedule 23 - 15+ kW (sec)	3.93%	3.93%	3.93%	3.10%	3.10%	3.10%	2.26%	2.33%
30	GS - Schedule 23 - Primary (pri)	0.03%	0.03%	0.03%	0.02%	0.02%	0.02%	0.02%	0.02%
31	GS - Schedule 28 - 0-50 kW (sec)	0.79%	0.79%	0.79%	0.58%	0.58%	0.58%	0.77%	0.76%
32	GS - Schedule 28 - 51-100 kW (sec)	0.58%	0.58%	0.58%	0.43%	0.43%	0.43%	0.57%	0.56%
33	GS - Schedule 28 - 100+ kW (sec)	0.33%	0.33%	0.33%	0.24%	0.24%	0.24%	0.32%	0.32%
34	GS - Schedule 28 - Primary (pri)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
35	GS - Schedule 30 - 0-300 kW (sec)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.04%	0.03%
36	GS - Schedule 30 - 300+ kW (sec)	0.06%	0.06%	0.06%	0.04%	0.04%	0.04%	0.09%	0.09%
37	GS - Schedule 30 - Primary (pri)	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.01%	0.01%
38	Irrigation - Sch 41	2.68%	2.68%	2.68%	4.20%	4.20%	4.20%	0.83%	1.06%
39	LPS - Schedule 48 - 1 - 4 MW (sec)	0.04%	0.04%	0.04%	0.01%	0.01%	0.01%	0.01%	0.01%
40	LPS - Schedule 48 - 1 - 4 MW (pri)	0.02%	0.02%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%
41	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
42	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
43	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
44									
45	Sum of Branch Customers								
46	1,2,3,6	5.08	5.08	5.08			23.55		38.80
47	1,2,3,4,5,6,7	5.08	5.08	5.08	23.55	23.55	23.55	1,088.39	1,174.30
48									
49	1,2,3,6	13.1%	13.1%	13.1%			60.7%		100.0%
50	1,2,3,4,5,6,7	0.4%	0.4%	0.4%	2.0%	2.0%	2.0%	92.7%	100.0%

PacifiCorp  
Oregon Circuit Model Study  
Circuit kW Load by Branch

Line	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
1	Hypothetical Circuit Branch								
2	Class	1	2	3	4	5	6	7	Total
3	Res - Schedule 4 (sec)	8.97	8.97	8.97	43.77	43.77	43.77	2,229.56	2,387.77
4	GS - Schedule 23 - 0-15 kW (sec)	1.15	1.15	1.15	4.21	4.21	4.21	141.78	157.89
5	GS - Schedule 23 - 15+ kW (sec)	1.29	1.29	1.29	4.70	4.70	4.70	158.14	176.10
6	GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.02	0.02	0.02	0.56	0.62
7	GS - Schedule 28 - 0-50 kW (sec)	0.56	0.56	0.56	1.92	1.92	1.92	118.39	125.85
8	GS - Schedule 28 - 51-100 kW (sec)	0.83	0.83	0.83	2.82	2.82	2.82	174.08	185.04
9	GS - Schedule 28 - 100+ kW (sec)	1.06	1.06	1.06	3.61	3.61	3.61	222.32	236.32
10	GS - Schedule 28 - Primary (pri)	0.03	0.03	0.03	0.09	0.09	0.09	5.32	5.66
11	GS - Schedule 30 - 0-300 kW (sec)	0.15	0.15	0.15	0.51	0.51	0.51	50.36	52.34
12	GS - Schedule 30 - 300+ kW (sec)	0.72	0.72	0.72	2.52	2.52	2.52	248.00	257.71
13	GS - Schedule 30 - Primary (pri)	0.07	0.07	0.07	0.25	0.25	0.25	24.37	25.32
14	Irrigation - Sch 41	1.28	1.28	1.28	9.28	9.28	9.28	84.66	116.32
15	LPS - Schedule 48 - 1 - 4 MW (sec)	1.36	1.36	1.36	1.82	1.82	1.82	123.37	132.91
16	LPS - Schedule 48 - 1 - 4 MW (pri)	1.28	1.28	1.28	1.71	1.71	1.71	115.91	124.88
17	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
18	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	18.75	18.75	18.75	77.21	77.21	77.21	3,696.84	3,984.72
20									
21	Source - 'Circuit Distribution Model Inputs & Calculations' (PC 3)								
22	Source - 'Average Customers by Hypothetical Circuit Branch' (PC 5)								
23	Customers multiplied by circuit kW per customer.								
24	For Example 9.0 is 3.68 Residential Customers multiplied by 2.43 average Dist. kW per Customer.								
25									
26	Percent of Branch Load								
27	Res - Schedule 4 (sec)	47.84%	47.84%	47.84%	56.69%	56.69%	56.69%	60.31%	59.92%
28	GS - Schedule 23 - 0-15 kW (sec)	6.16%	6.16%	6.16%	5.46%	5.46%	5.46%	3.84%	3.96%
29	GS - Schedule 23 - 15+ kW (sec)	6.87%	6.87%	6.87%	6.09%	6.09%	6.09%	4.28%	4.42%
30	GS - Schedule 23 - Primary (pri)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
31	GS - Schedule 28 - 0-50 kW (sec)	3.00%	3.00%	3.00%	2.49%	2.49%	2.49%	3.20%	3.16%
32	GS - Schedule 28 - 51-100 kW (sec)	4.42%	4.42%	4.42%	3.66%	3.66%	3.66%	4.71%	4.64%
33	GS - Schedule 28 - 100+ kW (sec)	5.64%	5.64%	5.64%	4.67%	4.67%	4.67%	6.01%	5.93%
34	GS - Schedule 28 - Primary (pri)	0.14%	0.14%	0.14%	0.11%	0.11%	0.11%	0.14%	0.14%
35	GS - Schedule 30 - 0-300 kW (sec)	0.78%	0.78%	0.78%	0.66%	0.66%	0.66%	1.36%	1.31%
36	GS - Schedule 30 - 300+ kW (sec)	3.83%	3.83%	3.83%	3.26%	3.26%	3.26%	6.71%	6.47%
37	GS - Schedule 30 - Primary (pri)	0.38%	0.38%	0.38%	0.32%	0.32%	0.32%	0.66%	0.64%
38	Irrigation - Sch 41	6.83%	6.83%	6.83%	12.01%	12.01%	12.01%	2.29%	2.92%
39	LPS - Schedule 48 - 1 - 4 MW (sec)	7.27%	7.27%	7.27%	2.35%	2.35%	2.35%	3.34%	3.34%
40	LPS - Schedule 48 - 1 - 4 MW (pri)	6.83%	6.83%	6.83%	2.21%	2.21%	2.21%	3.14%	3.13%
41	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
42	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
43	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
44									
45	Sum of Branch Loads								
46	1,2,3,6	18.75	18.75	18.75			77.21		133.45
47	1,2,3,4,5,6,7	18.75	18.75	18.75	77.21	77.21	77.21	3,696.84	3,984.72
48									
49	1,2,3,6	14.05%	14.05%	14.05%			57.86%		100.00%
50	1,2,3,4,5,6,7	0.47%	0.47%	0.47%	1.94%	1.94%	1.94%	92.78%	100.00%

PacifiCorp  
Oregon Circuit Model Study  
System-wide Pole and Conductor Costs

Adjusted Oregon Line Costs per Mile

	State Specific Account 364 Pole Statistics				Adjustment Factor
	Poles	Pole Feet	Pole Miles	Poles / Mile	
California	55,482	12,544,659	2,376	23.35	0.884
Idaho	97,406	21,318,575	4,038	24.12	0.913
Oregon	377,374	74,711,073	14,150	26.67	1.009
Utah	332,602	61,493,319	11,646	28.56	1.081
Washington	99,980	16,626,029	3,149	31.75	1.202
Wyoming	157,847	37,272,116	7,059	22.36	0.846
Total	1,120,691	223,965,771	42,418	26.42	1.000

Wire Size	Account 364 Pole Cost per Mile			Account 365 Conductor Cost per Mile	Total Line Construction Cost
	Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost		
1 Phase - 1/0 ACSR	\$25,517	1.009	\$25,758	\$12,789	\$38,547
3 Phase - 1/0 ACSR	\$48,426	1.009	\$48,883	\$28,548	\$77,431
3 Phase - 447 AAC & 4/0 AAC	\$54,011	1.009	\$54,521	\$62,952	\$117,473
3 Phase -795 AAC & 477 AAC	\$56,143	1.009	\$56,673	\$110,173	\$166,846

	Costs for Branches 1,2,3,4,5		
	1 Phase - 1/0 ACSR	3 Phase - 1/0 ACSR	Total
Poles	\$47,499	\$167,408	\$214,907
Conductors	\$23,583	\$97,767	\$121,350
Total	\$71,082	\$265,175	\$336,257

	Costs for Branch 6	Cost for Branch 7
	3 Phase - 447 AAC & 4/0 AAC	3 Phase -795 AAC & 477 AAC
Poles	\$287,255	\$298,594
Conductors	\$331,674	\$580,467
Total	\$618,929	\$879,060

Miles per Branch 5.27  
Single Phase Miles Per Branch 1.84  
Three Phase Miles Per Branch 3.42

Commitment and Demand Costs Per Branch

	Poles			Conductor		
	Total Cost	Commitment	Demand	Total Cost	Commitment	Demand
Branches 1,2,3,4,5						
1 Phase - 1/0 ACSR	\$47,499	\$47,499	\$0	\$23,583	\$23,583	\$0
3 Phase - 1/0 ACSR	\$167,408	\$88,212	\$79,196	\$97,767	\$43,798	\$53,969
Total Branches 1,2,3,4,5	\$214,907	\$135,711	\$79,196	\$121,350	\$67,381	\$53,969
Branch 6						
3 Phase - 447 AAC & 4/0 AAC	\$287,255	\$135,711	\$151,544	\$331,674	\$67,381	\$264,293
Branch 7						
3 Phase -795 AAC & 477 AAC	\$298,594	\$135,711	\$162,883	\$580,467	\$67,381	\$513,086
Total All Branches	\$1,660,384	\$949,976	\$710,408	\$1,518,892	\$471,668	\$1,047,223

Branch pole and conductor commitment costs equals single or three Phase Miles Per Branch Multiplied by 1 Phase - 1/0 ACSR Cost



PacifiCorp  
Oregon Circuit Model Study  
Calculation of Hypothetical Circuit Model Branch Cost

Conductors Type	(A) Total Cost		(C) Commitment Cost		(E) Demand Cost	
	Poles	Conductor	Poles	Conductor	Poles	Conductor
Branch 1						
1 Phase - 1/0 ACSR	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583		
3 Phase - 1/0 ACSR	\$ 167,408	\$ 97,767	\$ 88,212	\$ 43,798	\$ 79,196	\$ 53,969
Total segment	\$ 214,907	\$ 121,350	\$ 135,711	\$ 67,381	\$ 79,196	\$ 53,969
Branch 2						
1 Phase - 1/0 ACSR	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583		
3 Phase - 1/0 ACSR	\$ 167,408	\$ 97,767	\$ 88,212	\$ 43,798	\$ 79,196	\$ 53,969
Total Segments	\$ 214,907	\$ 121,350	\$ 135,711	\$ 67,381	\$ 79,196	\$ 53,969
Branch 3						
1 Phase - 1/0 ACSR	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583		
3 Phase - 1/0 ACSR	\$ 167,408	\$ 97,767	\$ 88,212	\$ 43,798	\$ 79,196	\$ 53,969
Total Segments	\$ 214,907	\$ 121,350	\$ 135,711	\$ 67,381	\$ 79,196	\$ 53,969
Branch 4						
1 Phase - 1/0 ACSR	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583		
3 Phase - 1/0 ACSR	\$ 167,408	\$ 97,767	\$ 88,212	\$ 43,798	\$ 79,196	\$ 53,969
Total Segments	\$ 214,907	\$ 121,350	\$ 135,711	\$ 67,381	\$ 79,196	\$ 53,969
Branch 5						
1 Phase - 1/0 ACSR	\$ 47,499	\$ 23,583	\$ 47,499	\$ 23,583		
3 Phase - 1/0 ACSR	\$ 167,408	\$ 97,767	\$ 88,212	\$ 43,798	\$ 79,196	\$ 53,969
Total Segments	\$ 214,907	\$ 121,350	\$ 135,711	\$ 67,381	\$ 79,196	\$ 53,969
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	\$ 287,255	\$ 331,674	\$ 135,711	\$ 67,381	\$ 151,544	\$ 264,293
Total Segments	\$ 287,255	\$ 331,674	\$ 135,711	\$ 67,381	\$ 151,544	\$ 264,293
Branch 7						
3 Phase -795 AAC & 477 AAC	\$ 298,594	\$ 580,467	\$ 135,711	\$ 67,381	\$ 162,883	\$ 513,086
Total segment	\$ 298,594	\$ 580,467	\$ 135,711	\$ 67,381	\$ 162,883	\$ 513,086
	\$3,179,275	\$1,660,384	\$949,976	\$471,668	\$710,408	\$1,047,223

Source - 'System-wide Pole and Conductor Costs' (PC 7)

PacifiCorp  
Oregon Circuit Model Study  
Pole Demand Calculations

Line	(A)	(B)	(C)			(D)	(E)	(F)	(G)	(H)	(I)
	1	2	Hypothetical Circuit Branch			4	5	6	7		
1 % customer	14.05%	14.05%	14.05%					57.86%		100.00%	
2 Branch 6 Cost	\$ 21,288	\$ 21,288	\$ 21,288					\$ 87,679		\$ 151,544	\$ / kW
3 % customer	0.47%	0.47%	0.47%	1.94%	1.94%	1.94%	92.78%			100.00%	
4 Branch 7 Cost	\$ 766	\$ 766	\$ 766	\$ 3,156	\$ 3,156	\$ 3,156	\$ 151,115	\$ 162,883			
5 Branch Commitment Cost	\$ 79,196	\$ 79,196	\$ 79,196	\$ 79,196	\$ 79,196						Average
6 Total	\$ 101,251	\$ 101,251	\$ 101,251	\$ 82,352	\$ 82,352	\$ 90,835	\$ 151,115	\$ 710,408	\$ 178.28		
7											
8											
9											
10 Class Cost per Branch	1	2	3	4	5	6	7	Total Demand Cost	\$ Per kW		
11 Res - Schedule 4 (sec)	\$ 48,440	\$ 48,440	\$ 48,440	\$ 46,683	\$ 46,683	\$ 51,491	\$ 91,137	\$ 381,314	\$ 159.69		
12 GS - Schedule 23 - 0-15 kW (sec)	\$ 6,233	\$ 6,233	\$ 6,233	\$ 4,494	\$ 4,494	\$ 4,957	\$ 5,796	\$ 38,439	\$ 243.46		
13 GS - Schedule 23 - 15+ kW (sec)	\$ 6,952	\$ 6,952	\$ 6,952	\$ 5,012	\$ 5,012	\$ 5,529	\$ 6,464	\$ 42,874	\$ 243.46		
14 GS - Schedule 23 - Primary (pri)	\$ 25	\$ 25	\$ 25	\$ 18	\$ 18	\$ 20	\$ 23	\$ 151	\$ 243.46		
15 GS - Schedule 28 - 0-50 kW (sec)	\$ 3,041	\$ 3,041	\$ 3,041	\$ 2,049	\$ 2,049	\$ 2,260	\$ 4,840	\$ 20,319	\$ 161.46		
16 GS - Schedule 28 - 51-100 kW (sec)	\$ 4,471	\$ 4,471	\$ 4,471	\$ 3,012	\$ 3,012	\$ 3,323	\$ 7,116	\$ 29,876	\$ 161.46		
17 GS - Schedule 28 - 100+ kW (sec)	\$ 5,710	\$ 5,710	\$ 5,710	\$ 3,847	\$ 3,847	\$ 4,243	\$ 9,088	\$ 38,155	\$ 161.46		
18 GS - Schedule 28 - Primary (pri)	\$ 137	\$ 137	\$ 137	\$ 92	\$ 92	\$ 102	\$ 218	\$ 913	\$ 161.46		
19 GS - Schedule 30 - 0-300 kW (sec)	\$ 788	\$ 788	\$ 788	\$ 545	\$ 545	\$ 601	\$ 2,059	\$ 6,115	\$ 116.84		
20 GS - Schedule 30 - 300+ kW (sec)	\$ 3,882	\$ 3,882	\$ 3,882	\$ 2,683	\$ 2,683	\$ 2,960	\$ 10,138	\$ 30,112	\$ 116.84		
21 GS - Schedule 30 - Primary (pri)	\$ 381	\$ 381	\$ 381	\$ 264	\$ 264	\$ 291	\$ 996	\$ 2,958	\$ 116.84		
22 Irrigation - Sch 41	\$ 6,911	\$ 6,911	\$ 6,911	\$ 9,893	\$ 9,893	\$ 10,913	\$ 3,461	\$ 54,893	\$ 471.90		
23 LPS - Schedule 48 - 1 - 4 MW (sec)	\$ 7,363	\$ 7,363	\$ 7,363	\$ 1,939	\$ 1,939	\$ 2,138	\$ 5,043	\$ 33,146	\$ 249.38		
24 LPS - Schedule 48 - 1 - 4 MW (pri)	\$ 6,917	\$ 6,917	\$ 6,917	\$ 1,821	\$ 1,821	\$ 2,009	\$ 4,738	\$ 31,142	\$ 249.38		
25 LPS - Schedule 48 - > 4 MW (sec)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
26 LPS - Schedule 48 - > 4 MW (pri)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
27 Check Total	\$ 101,251	\$ 101,251	\$ 101,251	\$ 82,352	\$ 82,352	\$ 90,835	\$ 151,115	\$ 710,408			

Sources: Line 1 & 3 - 'Circuit kW Load by Branch' (PC 6)  
 Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) for \$151,544  
 Line 1 X \$151,544  
 Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) for \$162,883  
 Line 3 X \$162,883  
 Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8)  
 Line 7 to 18 - Line 6 X Percent of Branch Load 'Circuit kW Load by Branch' (PC 6)

PacifiCorp  
Oregon Circuit Model Study  
Conductor Demand Calculations

Line	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Hypothetical Circuit Branch								
	1	2	3	4	5	6	7		
1 % customer	14.05%	14.05%	14.05%			57.86%		100.00%	
2 Branch 6 Cost	\$ 37,127	\$ 37,127	\$ 37,127			\$ 152,912		\$ 264,293	\$ / kW
3 % customer	0.47%	0.47%	0.47%	1.94%	1.94%	1.94%	92.78%	100.00%	
4 Branch 7 Cost	\$ 2,414	\$ 2,414	\$ 2,414	\$ 9,942	\$ 9,942	\$ 9,942	\$ 476,017	\$ 513,086	
5 Branch Commitment Cost	\$ 53,969	\$ 53,969	\$ 53,969	\$ 53,969	\$ 53,969				Average
6 Total	\$ 93,510	\$ 93,510	\$ 93,510	\$ 63,911	\$ 63,911	\$ 162,854	\$ 476,017	\$ 1,047,223	\$ 262.81
7									
8									
9									
10 Class Cost per Branch	1	2	3	4	5	6	7	Total Demand Cost	\$ Per kW
11 Res - Schedule 4 (sec)	\$ 44,737	\$ 44,737	\$ 44,737	\$ 36,229	\$ 36,229	\$ 92,316	\$ 287,085	\$ 586,070	\$ 245.45
12 GS - Schedule 23 - 0-15 kW (sec)	\$ 5,756	\$ 5,756	\$ 5,756	\$ 3,488	\$ 3,488	\$ 8,887	\$ 18,256	\$ 51,387	\$ 325.47
13 GS - Schedule 23 - 15+ kW (sec)	\$ 6,421	\$ 6,421	\$ 6,421	\$ 3,890	\$ 3,890	\$ 9,912	\$ 20,363	\$ 57,317	\$ 325.47
14 GS - Schedule 23 - Primary (pri)	\$ 23	\$ 23	\$ 23	\$ 14	\$ 14	\$ 35	\$ 72	\$ 202	\$ 325.47
15 GS - Schedule 28 - 0-50 kW (sec)	\$ 2,808	\$ 2,808	\$ 2,808	\$ 1,590	\$ 1,590	\$ 4,051	\$ 15,245	\$ 30,900	\$ 245.54
16 GS - Schedule 28 - 51-100 kW (sec)	\$ 4,129	\$ 4,129	\$ 4,129	\$ 2,338	\$ 2,338	\$ 5,957	\$ 22,415	\$ 45,435	\$ 245.54
17 GS - Schedule 28 - 100 + kW (sec)	\$ 5,273	\$ 5,273	\$ 5,273	\$ 2,986	\$ 2,986	\$ 7,608	\$ 28,627	\$ 58,026	\$ 245.54
18 GS - Schedule 28 - Primary (pri)	\$ 126	\$ 126	\$ 126	\$ 71	\$ 71	\$ 182	\$ 685	\$ 1,389	\$ 245.54
19 GS - Schedule 30 - 0-300 kW (sec)	\$ 728	\$ 728	\$ 728	\$ 423	\$ 423	\$ 1,078	\$ 6,485	\$ 10,593	\$ 202.41
20 GS - Schedule 30 - 300+ kW (sec)	\$ 3,586	\$ 3,586	\$ 3,586	\$ 2,083	\$ 2,083	\$ 5,307	\$ 31,934	\$ 52,162	\$ 202.41
21 GS - Schedule 30 - Primary (pri)	\$ 352	\$ 352	\$ 352	\$ 205	\$ 205	\$ 521	\$ 3,137	\$ 5,125	\$ 202.41
22 Irrigation - Sch 41	\$ 6,383	\$ 6,383	\$ 6,383	\$ 7,678	\$ 7,678	\$ 19,565	\$ 10,901	\$ 64,969	\$ 558.52
23 LPS - Schedule 48 - 1 - 4 MW (sec)	\$ 6,800	\$ 6,800	\$ 6,800	\$ 1,505	\$ 1,505	\$ 3,834	\$ 15,886	\$ 43,128	\$ 324.48
24 LPS - Schedule 48 - 1 - 4 MW (pri)	\$ 6,388	\$ 6,388	\$ 6,388	\$ 1,414	\$ 1,414	\$ 3,602	\$ 14,925	\$ 40,519	\$ 324.48
25 LPS - Schedule 48 - > 4 MW (sec)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
26 LPS - Schedule 48 - > 4 MW (pri)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
27 Check Total	\$ 93,510	\$ 93,510	\$ 93,510	\$ 63,911	\$ 63,911	\$ 162,854	\$ 476,017	\$ 1,047,223	

PacifiCorp  
Oregon Circuit Model Study  
Pole Commitment Calculations

Line	(A)	(B)	(C)	(D)		(E)	(F)	(G)	(H)	(I)
	1	2	3	Hypothetical Circuit Branch		5	6	7		
1	% customer	13.10%	13.10%	13.10%			60.69%		100.00%	
2	Branch 6 Cost	\$ -	\$ -	\$ -			\$ -		\$ -	\$ Per
3	% customer	0.43%	0.43%	0.43%	2.01%	2.01%	2.01%	92.68%	100.00%	Customer
4	Branch 7 Cost	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
5	Branch Commitment Cost	\$ 135,711	\$ 135,711	\$ 135,711	\$ 135,711	\$ 135,711	\$ 135,711	\$ 135,711		Average
6	Total	\$ 135,711	\$ 135,711	\$ 135,711	\$ 135,711	\$ 135,711	\$ 135,711	\$ 135,711	\$ 949,976	\$ 808.97
7										
8										
9										
10	Class Cost per Branch	1	2	3	4	5	6	7	Total Commitment Cost	\$ Per Customer
11	Res - Schedule 4 (sec)	\$ 98,326	\$ 98,326	\$ 98,326	\$ 103,582	\$ 103,582	\$ 103,582	\$ 114,170	\$ 719,894	\$ 734.13
12	GS - Schedule 23 - 0-15 kW (sec)	\$ 25,854	\$ 25,854	\$ 25,854	\$ 20,377	\$ 20,377	\$ 20,377	\$ 14,837	\$ 153,530	\$ 1,158.69
13	GS - Schedule 23 - 15+ kW (sec)	\$ 5,337	\$ 5,337	\$ 5,337	\$ 4,206	\$ 4,206	\$ 4,206	\$ 3,062	\$ 31,690	\$ 1,158.69
14	GS - Schedule 23 - Primary (pri)	\$ 43	\$ 43	\$ 43	\$ 34	\$ 34	\$ 34	\$ 24	\$ 253	\$ 1,158.69
15	GS - Schedule 28 - 0-50 kW (sec)	\$ 1,067	\$ 1,067	\$ 1,067	\$ 786	\$ 786	\$ 786	\$ 1,048	\$ 6,608	\$ 739.44
16	GS - Schedule 28 - 51-100 kW (sec)	\$ 789	\$ 789	\$ 789	\$ 581	\$ 581	\$ 581	\$ 775	\$ 4,884	\$ 739.44
17	GS - Schedule 28 - 100 + kW (sec)	\$ 446	\$ 446	\$ 446	\$ 328	\$ 328	\$ 328	\$ 438	\$ 2,759	\$ 739.44
18	GS - Schedule 28 - Primary (pri)	\$ 15	\$ 15	\$ 15	\$ 11	\$ 11	\$ 11	\$ 15	\$ 95	\$ 739.44
19	GS - Schedule 30 - 0-300 kW (sec)	\$ 30	\$ 30	\$ 30	\$ 23	\$ 23	\$ 23	\$ 49	\$ 210	\$ 512.16
20	GS - Schedule 30 - 300+ kW (sec)	\$ 76	\$ 76	\$ 76	\$ 57	\$ 57	\$ 57	\$ 122	\$ 521	\$ 512.16
21	GS - Schedule 30 - Primary (pri)	\$ 7	\$ 7	\$ 7	\$ 6	\$ 6	\$ 6	\$ 12	\$ 52	\$ 512.16
22	Irrigation - Sch 41	\$ 3,641	\$ 3,641	\$ 3,641	\$ 5,698	\$ 5,698	\$ 5,698	\$ 1,125	\$ 29,142	\$ 2,350.27
23	LPS - Schedule 48 - 1 - 4 MW (sec)	\$ 48	\$ 48	\$ 48	\$ 14	\$ 14	\$ 14	\$ 20	\$ 205	\$ 1,173.53
24	LPS - Schedule 48 - 1 - 4 MW (pri)	\$ 32	\$ 32	\$ 32	\$ 9	\$ 9	\$ 9	\$ 13	\$ 136	\$ 1,173.53
25	LPS - Schedule 48 - > 4 MW (sec)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
26	LPS - Schedule 48 - > 4 MW (pri)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
27	Check Total	\$ 135,711	\$ 135,711	\$ 135,711	\$ 135,711	\$ 135,711	\$ 135,711	\$ 135,711	\$ 949,976	

PacifiCorp  
Oregon Circuit Model Study  
Conductor Commitment Calculations

Line	(A)	(B)	(C)	(D)		(E)	(F)	(G)	(H)	(I)
	1	2	3	Hypothetical Circuit Branch		5	6	7		
1 % customer	13.10%	13.10%	13.10%				60.69%		100.00%	
2 Branch 6 Cost	\$ -	\$ -	\$ -				\$ -		\$ -	\$ Per
3 % customer	0.43%	0.43%	0.43%	2.01%	2.01%	2.01%	2.01%	92.68%	100.00%	Customer
4 Branch 7 Cost	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
5 Branch Commitment Cost	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	Average
6 Total	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 471,668	\$ 401.66
7										
8										
9										
10 Class Cost per Branch	1	2	3	4	5	6	7	Total Commitment Cost	\$ Per Customer	
11 Res - Schedule 4 (sec)	\$ 48,820	\$ 48,820	\$ 48,820	\$ 51,429	\$ 51,429	\$ 51,429	\$ 56,686	\$ 357,431	\$ 364.50	
12 GS - Schedule 23 - 0-15 kW (sec)	\$ 12,837	\$ 12,837	\$ 12,837	\$ 10,117	\$ 10,117	\$ 10,117	\$ 7,366	\$ 76,228	\$ 575.29	
13 GS - Schedule 23 - 15+ kW (sec)	\$ 2,650	\$ 2,650	\$ 2,650	\$ 2,088	\$ 2,088	\$ 2,088	\$ 1,520	\$ 15,734	\$ 575.29	
14 GS - Schedule 23 - Primary (pri)	\$ 21	\$ 21	\$ 21	\$ 17	\$ 17	\$ 17	\$ 12	\$ 126	\$ 575.29	
15 GS - Schedule 28 - 0-50 kW (sec)	\$ 530	\$ 530	\$ 530	\$ 390	\$ 390	\$ 390	\$ 520	\$ 3,281	\$ 367.14	
16 GS - Schedule 28 - 51-100 kW (sec)	\$ 392	\$ 392	\$ 392	\$ 288	\$ 288	\$ 288	\$ 385	\$ 2,425	\$ 367.14	
17 GS - Schedule 28 - 100 + kW (sec)	\$ 221	\$ 221	\$ 221	\$ 163	\$ 163	\$ 163	\$ 217	\$ 1,370	\$ 367.14	
18 GS - Schedule 28 - Primary (pri)	\$ 8	\$ 8	\$ 8	\$ 6	\$ 6	\$ 6	\$ 7	\$ 47	\$ 367.14	
19 GS - Schedule 30 - 0-300 kW (sec)	\$ 15	\$ 15	\$ 15	\$ 11	\$ 11	\$ 11	\$ 24	\$ 104	\$ 254.29	
20 GS - Schedule 30 - 300+ kW (sec)	\$ 38	\$ 38	\$ 38	\$ 28	\$ 28	\$ 28	\$ 61	\$ 259	\$ 254.29	
21 GS - Schedule 30 - Primary (pri)	\$ 4	\$ 4	\$ 4	\$ 3	\$ 3	\$ 3	\$ 6	\$ 26	\$ 254.29	
22 Irrigation - Sch 41	\$ 1,808	\$ 1,808	\$ 1,808	\$ 2,829	\$ 2,829	\$ 2,829	\$ 559	\$ 14,469	\$ 1,166.92	
23 LPS - Schedule 48 - 1 - 4 MW (sec)	\$ 24	\$ 24	\$ 24	\$ 7	\$ 7	\$ 7	\$ 10	\$ 102	\$ 582.66	
24 LPS - Schedule 48 - 1 - 4 MW (pri)	\$ 16	\$ 16	\$ 16	\$ 5	\$ 5	\$ 5	\$ 7	\$ 67	\$ 582.66	
25 LPS - Schedule 48 - > 4 MW (sec)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
26 LPS - Schedule 48 - > 4 MW (pri)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
27 Check Total	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 67,381	\$ 471,668		

PC 13

PacifiCorp  
Oregon Circuit Model Study  
Dedicated Circuit Trunk Costs  
For Large Customers

	Voltage Delivery			
	Large GS + 4 MW (pri)		Large GS + 4 MW (sec)	
	Poles	Conductor	Poles	Conductor
1 Construction Cost Per Mile	\$ 56,673	\$ 110,173	\$ 56,673	\$ 110,173
2 Average Trunk Length	0.67 miles		0.67 miles	
3 Total Construction Cost	\$ 37,971	\$ 73,816	\$ 37,971	\$ 73,816
4 Customer Peak Demand	4,256 kW		4,764 kW	
5 Demand Cost \$/kW	\$8.92	\$17.34	\$7.97	\$15.49

Construction Costs for Distribution Line type - 3 Phase -795 AAC & 477 AAC.

Line 1 - 'System-wide Pole and Conductor Costs' (PC 7)

Line 2 - Distribution Engineering Studies

Line 3 - Line 1 multiplied by Line 2

Line 4 - 'Circuit Distribution Model Inputs & Calculations' (PC 3)

Line 5 - Line 3 divided by Line 4

PacifiCorp  
Oregon Circuit Model Study  
Trunk All Demand Costs  
Outer Branches Commitment & Demand  
Three Phase As Needed

Line	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Commitment \$/Customer Poles	Conductor	Demand \$/Dist. kW Poles	Conductor	Typical circuit Customers	kW	=(C)*(F) Poles	=(D)*(F) Conductor
1	Res - Schedule 4 (sec)	\$ 734.13	\$ 364.50	\$ 159.69	\$ 245.45	980.6	2,387.77	\$ 381,314	\$ 586,070
2	GS - Schedule 23 - 0-15 kW (sec)	\$ 1,158.69	\$ 575.29	\$ 243.46	\$ 325.47	132.5	157.89	\$ 38,439	\$ 51,387
3	GS - Schedule 23 - 15+ kW (sec)	\$ 1,158.69	\$ 575.29	\$ 243.46	\$ 325.47	27.3	176.10	\$ 42,874	\$ 57,317
4	GS - Schedule 23 - Primary (pri)	\$ 1,158.69	\$ 575.29	\$ 243.46	\$ 325.47	0.2	0.62	\$ 151	\$ 202
5	GS - Schedule 28 - 0-50 kW (sec)	\$ 739.44	\$ 367.14	\$ 161.46	\$ 245.54	8.9	125.85	\$ 20,319	\$ 30,900
6	GS - Schedule 28 - 51-100 kW (sec)	\$ 739.44	\$ 367.14	\$ 161.46	\$ 245.54	6.6	185.04	\$ 29,876	\$ 45,435
7	GS - Schedule 28 - 100 + kW (sec)	\$ 739.44	\$ 367.14	\$ 161.46	\$ 245.54	3.7	236.32	\$ 38,155	\$ 58,026
8	GS - Schedule 28 - Primary (pri)	\$ 739.44	\$ 367.14	\$ 161.46	\$ 245.54	0.1	5.66	\$ 913	\$ 1,389
9	GS - Schedule 30 - 0-300 kW (sec)	\$ 512.16	\$ 254.29	\$ 116.84	\$ 202.41	0.4	52.34	\$ 6,115	\$ 10,593
10	GS - Schedule 30 - 300+ kW (sec)	\$ 512.16	\$ 254.29	\$ 116.84	\$ 202.41	1.0	257.71	\$ 30,112	\$ 52,162
11	GS - Schedule 30 - Primary (pri)	\$ 512.16	\$ 254.29	\$ 116.84	\$ 202.41	0.1	25.32	\$ 2,958	\$ 5,125
12	Irrigation - Sch 41	\$ 2,350.27	\$ 1,166.92	\$ 471.90	\$ 558.52	12.4	116.32	\$ 54,893	\$ 64,969
13	LPS - Schedule 48 - 1 - 4 MW (sec)	\$ 1,173.53	\$ 582.66	\$ 249.38	\$ 324.48	0.2	132.91	\$ 33,146	\$ 43,128
14	LPS - Schedule 48 - 1 - 4 MW (pri)	\$ 1,173.53	\$ 582.66	\$ 249.38	\$ 324.48	0.1	124.88	\$ 31,142	\$ 40,519
15	Total -	\$ 808.97	\$ 401.66	\$ 178.28	\$ 262.81	1,174.3	3,984.7	\$ 710,408	\$ 1,047,223
16									
17	Large GS + 4 MW (sec)	\$ -	\$ -	\$ 7.97	\$ 15.49	-	4,763.92	\$ 37,971	\$ 73,816
18	Large GS + 4 MW (pri)	\$ -	\$ -	\$ 8.92	\$ 17.34	-	4,256.39	\$ 37,971	\$ 73,816
								\$ 786,350	\$ 1,194,855

	Commitment	Demand	Total
Poles	\$ 949,976	\$ 786,350	\$ 1,736,326
Conductor	\$ 471,668	\$ 1,194,855	\$ 1,666,524
Total	\$ 1,421,644	\$ 1,981,205	\$ 3,402,849

Source : Column (A) - Pole Commitment Calculations' (PC 11)  
 Column (B) - Conductor Commitment Calculations' (PC 12)  
 Column (C) - Pole Demand Calculations' (PC 9)  
 Column (D) - Conductor Demand Calculations' (PC 10)  
 Column (E) - Average Customers by Hypothetical Circuit Branch' (PC 5)  
 Column (F) - Circuit kW Load by Branch' (PC 6)

PacifiCorp  
Oregon Marginal Cost Study  
Transformer Commitment Costs

Line	Customer Type	(A) Percent of Customers	(B) Dollars / Tran.	(C) Weighted \$/ Tran. (A) x (B)	(D) # Cust. / Tran.	(E) Transformer \$/ Cust. (C) / (D)	(F) Average Customers	(G) Tot. Trans. Commitment \$ (E) x (F)
1	Res - Schedule 4	100.00%	240.75	240.75	4.09	<u>\$58.91</u>	535,059	\$31,520,326
2								
3	GS - Schedule 23							
4	1 Phase	80.83%	240.75	194.60	2.66	\$73.11		
5	3 Phase	19.17%	753.04	144.37	3.17	<u>\$45.54</u>		
6	0-15 kW	100.00%				<u>\$118.65</u>	69,806	\$8,282,213
7								
8	1 Phase	54.35%	240.75	130.85	2.66	\$49.16		
9	3 Phase	45.65%	753.04	343.77	3.17	<u>\$108.43</u>		
10	15+ kW	100.00%				<u>\$157.59</u>	14,408	\$2,270,516
11								
12	Primary	100.00%	-	-	-	0	115	\$0
13								
14	GS - Schedule 28							
15	1 Phase	28.88%	240.75	69.53	1.23	\$56.53		
16	3 Phase	71.12%	753.04	535.57	1.24	<u>\$431.91</u>		
17	0-50 kW	100.00%				<u>\$488.44</u>	4,819	\$2,353,791.13
18								
19	1 Phase	12.69%	240.75	30.55	1.23	\$24.84		
20	3 Phase	87.31%	753.04	657.49	1.24	<u>\$530.23</u>		
21	51-100 kW	100.00%				<u>\$555.07</u>	3,562	\$1,977,164
22								
23	1 Phase	1.56%	240.75	3.76	1.23	\$3.06		
24	3 Phase	98.44%	753.04	741.27	1.24	<u>\$597.80</u>		
25	100+ kW	100.00%				<u>\$600.86</u>	2,012	\$1,208,921
26								
27	Primary	100.00%	-	-	-	0	69	\$0
28								
29	GS - Schedule 30							
30	1 Phase	0.47%	240.75	1.13	1.07	\$1.06		
31	3 Phase	99.53%	753.04	749.52	1.10	<u>\$681.38</u>		
32	0-300 kW	100.00%				<u>\$682.44</u>	213	\$145,359
33								
34	1 Phase	0.00%	240.75	-	1.07	\$0.00		
35	3 Phase	100.00%	753.04	753.04	1.10	<u>\$684.58</u>		
36	300+ kW	100.00%				<u>\$684.58</u>	531	\$363,513
37								
38	Primary	100.00%	-	-	0.00	0	53	\$0
39								
40	LPS - Schedule 48							
41	1 - 4 MW (sec)	100.00%	753.04	753.04	1.10	\$684.58	92	\$62,982
42	1 - 4 MW (pri)	100.00%	-	-	0.00	\$0.00	61	\$0
43	> 4 MW (sec)	100.00%	753.04	753.04	1.10	\$684.58	1	\$685
44	> 4 MW (pri)	100.00%	-	-	0.00	\$0.00	28	\$0
45	Trans (tm)	100.00%	-	-	0.00	\$0.00	8	\$0
46								
47	Schedule 41- Irrigation							
48	1 Phase	15.50%	240.75	37.32	1.30	\$28.71		
49	3 Phase	84.50%	753.04	636.31	1.19	<u>\$534.71</u>		
50	Total	100.00%				<u>\$563.42</u>	7,997	\$4,505,686



XFMR 2

PacifiCorp  
Oregon Marginal Cost Study  
Transformer Demand Costs

Line	Customer Type		(A)	(B)	(C)
			Weighted \$/ kW	Transformer Peak kW	Tot. Trans. Demand \$ (A) x (B)
1	Res - Schedule 4	(sec)	\$1.02	3,413,133	\$3,492,797
2					
3	GS - Schedule 23				
4	0-15 kW	(sec)	\$1.02	419,071	\$428,852
5	15+ kW	(sec)	\$1.02	259,999	\$266,068
6	Primary	(pri)	\$0.00	0	\$0
7					
8	GS - Schedule 28				
9	0-50 kW	(sec)	\$1.02	269,617	\$275,909
10	51-100 kW	(sec)	\$1.02	444,697	\$455,076
11	100 + kW	(sec)	\$1.02	349,255	\$357,407
12	Primary	(pri)	\$0.00	0	\$0
13					
14	GS - Schedule 30				
15	0-300 kW	(sec)	\$1.02	63,411	\$64,891
16	300+ kW	(sec)	\$1.02	239,143	\$244,724
17	Primary	(pri)	\$0.00	0	\$0
18					
19					
20	LPS - Schedule 48				
21	1 - 4 MW	(sec)	\$1.02	119,399	\$122,186
22	1 - 4 MW	(pri)	\$0.00	0	\$0
23	> 4 MW	(sec)	\$1.02	8,225	\$8,417
24	> 4 MW	(pri)	\$0.00	0	\$0
25	Trans	(trn)	\$0.00	0	\$0
26					
27	Irrigation - Schedule 41 (Average)				
28	Secondary	(sec)	\$1.02	211,511	\$216,448
29					
30	Totals			5,797,461	\$5,932,775

XFMR 3

PacifiCorp  
Oregon Marginal Cost Study  
Calculation of Escalation Factors for Transformers  
(Regression weighted by number of transformer banks)

Line	Description	(A) Demand Related	(B) Adjusted for System Power Factor of 0.95	(C) Commitment Related	(D) Indexed to 2023	(E) Annualized \$ @ 6.97%
			(A) / 0.95		(B) or (C) x 1.0605	(D) x 6.97%
1	1 Phase \$/kW	\$13.15	\$13.84		\$14.68	\$1.02
2						
3	3 Phase \$/kW	\$13.15	\$13.84		\$14.68	\$1.02
4						
5	1 Phase			\$3,257.07	\$3,454.12	\$240.75
6	\$/Transformer					
7						
8	3 Phase			\$6,930.63		
9	Dummy Variable					
10						
11	3 Phase			\$10,187.70	\$10,804.06	\$753.04
12	\$/Transformer					

Index		Escalation Factor
<u>2021</u>	<u>2023</u>	<u>2021 - 2023</u>
1.0406	1.1035	1.0605

Dist OM

PacifiCorp  
Oregon Marginal Cost Study  
Distribution O&M Expense  
Loading Factor as a Percent of Dist. Plant  
(Excluding Meters and St Ltg)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
Line	Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	<u>Distribution O &amp; M Expenses</u>										
1	Total Distribution O & M Expense	66,557,786	67,568,987	68,689,786	70,580,614	69,136,197	61,535,374	61,513,756	61,139,370	68,212,991	83,124,296
2	Less:										
3	585 St Ltg & Signal Systems	63,875	60,545	54,154	61,627	58,974	64,715	39,416	64,984	59,838	74,457
4	586 Meter Expense	3,548,094	3,194,944	2,991,325	3,120,160	2,616,262	1,645,292	1,079,103	883,546	655,758	1,279,281
5	587 Customer Installation Expense	4,633,258	4,311,287	4,352,166	4,244,231	4,157,616	5,227,622	5,089,251	5,107,333	5,763,027	6,702,788
6	596 Main. of St Ltg & Signal Systems	1,251,031	1,084,668	1,057,829	918,033	896,454	953,051	879,053	889,400	890,418	831,495
7	597 Main. of Meters	1,386,968	1,556,466	1,628,742	1,653,908	1,198,881	10,098	59,787	85,408	231,001	235,870
8											
9	Total Adjusted Distribution O & M Expense	55,674,560	57,361,078	58,605,569	60,582,655	60,208,010	53,634,596	54,367,145	54,108,699	60,612,949	74,000,405
10	Line 1 - (Lines 3 through 7)										
11											
12											
13	<u>Distribution Plant</u>										
14	Total Distribution Plant	1,733,406,361	1,780,993,170	1,823,007,262	1,866,641,345	1,916,622,378	1,970,302,647	2,040,304,183	2,128,892,665	2,179,547,153	2,311,229,537
15	Less:										
16	370 Meters	59,771,898	59,665,589	59,706,364	60,110,283	60,993,623	62,541,755	65,791,804	76,927,946	90,849,203	96,302,523
17	373 Street Lighting	21,961,746	22,297,246	22,570,478	22,805,367	23,072,497	23,284,230	23,564,547	23,857,078	24,085,782	24,386,485
18											
19	Adjusted Distribution Plant	1,651,672,717	1,699,030,335	1,740,730,420	1,783,725,695	1,832,556,258	1,884,476,662	1,950,947,833	2,028,107,642	2,064,612,168	2,190,540,529
20	Line 14 - Line 16 - Line 17										
21											
22											
23	<u>O &amp; M Expense Loading Factor</u>										
24	Distribution O & M Loading	3.37%	3.38%	3.37%	3.40%	3.29%	2.85%	2.79%	2.67%	2.94%	3.38%
25	Line 9 / Line 19										
26											
27	Average Distribution O & M Loading	3.14%									
28	Average of Line 24										
29											
30	Distribution Annual Charge	6.97%									
31											
32	Annualized Distribution O & M Loading Factor	45.05%									
33	Line 27 / Line 30										

Footnotes:

Source: FERC Form 1 (State of Oregon) & Results of Operations

PacifiCorp  
Oregon Marginal Cost Study  
Weighted Average Installed Service Drop Costs  
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

Line	Load Class	(A) Customers	(B) % 1 & 3 Phase (A) / (A,Ttl)	(C) Overhead Service Drop Cost	(D) Underground Service Drop Cost	(E) % Overhead	(F) % Underground	(G) Weighted Service Drop Cost	(H) Weighted Service Drop Cost 1 & 3 Phase (B) x (E)	(I) Weighted Service Drop Cost 1 Phase	(J) Weighted Service Drop Cost 3 Phase
1	Res - Schedule 4	519,723	100.00%					\$749	\$749	\$749	
2	Annualized - Line 1 x 6.97%								\$52	\$52	
3											
4	GS - Schedule 23										
5	0-15 kW										
6	kW = 0, 1 Phase	4,515	6.43%	\$958	\$771	61.6%	38.4%	\$886	\$57	\$70	
7	kW = 0, 3 Phase	105	0.15%	\$1,176	\$1,089	61.6%	38.4%	\$1,143	\$2		\$9
8	kW > 1, 1 Phase	52,248	74.40%	\$1,067	\$814	61.6%	38.4%	\$970	\$722	\$893	
9	kW > 1, 3 Phase	13,359	19.02%	\$1,277	\$1,146	61.6%	38.4%	\$1,227	\$233		\$1,217
10	Total 0-15 kW	70,227	100.00%						\$1,014	\$963	\$1,226
11	Annualized - Line 10 x 6.97%								\$71	\$67	\$85
12											
13	15+ kW										
14	1 Phase	7,878	54.35%	\$1,920	\$1,441	61.6%	38.4%	\$1,736	\$943	\$1,736	
15	3 Phase	6,617	45.65%	\$2,313	\$2,107	61.6%	38.4%	\$2,234	\$1,020		\$2,234
16	Total 15+ kW	14,495	100.00%						\$1,963	\$1,736	\$2,234
17	Annualized - Line 16 x 6.97%								\$137	\$121	\$156
18											
19	Primary										
20	12.47 KV 4-wire Wye	116	100.00%					\$0			
21	Annualized - (Line 20) x 6.97%							\$0	\$0	\$0	\$0
22											
23	GS - Schedule 28										
24	0-50 kW										
25	1 Phase	1,368	28.88%	\$1,920	\$1,441	40.4%	59.6%	\$1,634	\$472	\$1,634	
26	3 Phase	3,369	71.12%	\$2,313	\$2,107	40.4%	59.6%	\$2,190	\$1,558		\$2,190
27	Total 0-50 kW	4,736	100.00%						\$2,030	\$1,634	\$2,190
28	Annualized - Line 27 x 6.97%								\$141	\$114	\$153
29											
30	51-100 kW										
31	1 Phase	444	12.69%	\$1,920	\$1,441	40.4%	59.6%	\$1,634	\$207	\$1,634	
32	3 Phase	3,056	87.31%	\$2,313	\$2,107	40.4%	59.6%	\$2,190	\$1,912		\$2,190
33	Total 51-100 kW	3,501	100.00%						\$2,120	\$1,634	\$2,190
34	Annualized - Line 33 x 6.97%								\$148	\$114	\$153
35											
36	100 + kW										
37	1 Phase	31	1.56%	\$3,535	\$4,423	40.4%	59.6%	\$4,064	\$64	\$4,064	
38	3 Phase	1,946	98.44%	\$4,117	\$4,103	40.4%	59.6%	\$4,109	\$4,044		\$4,109
39	Total 100 + kW	1,977	100.00%						\$4,108	\$4,064	\$4,109
40	Annualized - Line 39 x 6.97%								\$286	\$283	\$286
41											
42	Primary										
43	12.47 KV 4-wire Wye	68	100.00%					\$0	\$0		\$0
44	Annualized - (Line 43) x 6.97%								\$0	\$0	\$0

Services 2

PacifiCorp  
Oregon Marginal Cost Study  
Weighted Average Installed Service Drop Costs  
GS - Schedule 30 / LPS - Schedule 48

Line	Load Class	(A) Customers	(B) % 1 & 3 Phase (A) / (A,Ttl)	(C) Overhead Service Drop Cost	(D) Underground Service Drop Cost	(E) % Overhead	(F) % Underground	(G) Weighted Service Drop Cost	(H) Weighted Service Drop Cost 1 & 3 Phase (B) x (E)
1	GS - Schedule 30								
2									
3	0-300 kW								
4	1 Phase	1	0.47%	\$3,535	\$4,423	18.1%	81.9%	\$4,262	\$19.93
5	3 Phase	216	99.53%	\$4,117	\$4,103	18.1%	81.9%	\$4,106	\$4,086.38
6	Total 0-300 kW	217	100.00%						\$4,106.31
7	Annualized - Line 6 x 6.97%								\$286.21
8									
9	300+ kW								
10	1 Phase	0	0.00%	\$8,937	\$7,677	18.1%	81.9%	\$7,905	\$0.00
11	3 Phase	539	100.00%	\$8,937	\$7,677	18.1%	81.9%	\$7,905	\$7,905.20
12	Total 300+ kW	539	100.00%						\$7,905.20
13	Annualized - Line 12 x 6.97%								\$550.99
14									
15	Primary								
16	12.47 KV 4-wire Wye	53	100.00%					\$0	\$0.00
17	Annualized - Line 16 x 6.97%								\$0.00
18									
19	LPS - Schedule 48								
20	1 - 4 MW (sec)	93	100.00%		\$27,042	0.0%	100.0%	\$27,042	\$27,041.69
21	Annualized - Line 20 x 6.97%								\$1,884.81
22									
23	1 - 4 MW (pri)	61	100.00%					\$0	\$0.00
24	Annualized - Line 23 x 6.97%								\$0.00
25									
26	> 4 MW (sec)	1	100.00%		\$27,042	0.0%	100.0%	\$27,042	\$27,041.69
27	Annualized - Line 26 x 6.97%								\$1,884.81
28									
29	> 4 MW (pri)	28	100.00%					\$0	\$0.00
30	Annualized - Line 29 x 6.97%								\$0.00
31									
32	Trans (trn)	8	100.00%					\$0	\$0.00
33	Annualized - Line 32 x 6.97%								\$0.00

Services 3

PacifiCorp  
Oregon Marginal Cost Study  
Summary of Average Installed Costs  
Service Drops

Line	Load Class	(A) Service Conductor	(B) Cost	(C) Indexed to 2023 (B) x 1.0605	(D) Percent Use	(E) Total Cost per Service
<u>Residential</u>						
1	OH - small load	#2 Triplex*	\$630	\$668	30.5%	\$203.89
2	OH - all electric	1/0 Triplex	\$727	\$771	27.1%	\$208.78
3	UG - small load	1/0 Triplex	\$727	\$771	18.9%	\$145.55
4	UG - all electric	4/0 Triplex	\$766	\$812	23.5%	<u>\$191.11</u>
5						\$749.32
6	<u>0 - 15 kW</u>					
7	kW = 0, 1 Phase	OH - 1/0 Triplex	\$903	\$958		
8	kW = 0, 1 Phase	UG - 1/0 Triplex	\$727	\$771		
9	kW = 0, 3 Phase	OH - 1/0 Quadruplex	\$1,109	\$1,176		
10	kW = 0, 3 Phase	UG - 1/0 Quadruplex	\$1,027	\$1,089		
11	kW > 1, 1 Phase	OH - 4/0 Triplex	\$1,006	\$1,067		
12	kW > 1, 1 Phase	UG - 4/0 Triplex	\$768	\$814		
13	kW > 1, 3 Phase	OH - 4/0 Quadruplex	\$1,204	\$1,277		
14	kW > 1, 3 Phase	UG - 4/0 Quadruplex	\$1,081	\$1,146		
15						
16	<u>16 - 100 kW</u>					
17	1 Phase	OH - 2-4/0 Triplex	\$1,810	\$1,920		
18	1 Phase	UG - 2-4/0 Triplex	\$1,359	\$1,441		
19	3 Phase	OH - 2-4/0 Quadruplex	\$2,181	\$2,313		
20	3 Phase	UG - 2-4/0 Quadruplex	\$1,987	\$2,107		
21						
22	<u>101 - 300 kW</u>					
23	1 Phase	3-500 & 350N	\$3,333	\$3,535		
24	1 Phase	3- 750 & 500 N	\$4,171	\$4,423		
25	3 Phase	OH - 3-4/0 Quadruplex	\$3,882	\$4,117		
26	3 Phase	4-350 Quad	\$3,869	\$4,103		
27						
28	<u>301 - 1000 kW</u>					
29	3 Phase	3-750 kemil Quad.	\$8,427	\$8,937		
30	3 Phase	4-750 kemil Quad.	\$7,239	\$7,677		
31						
32	<u>1000 kW and Over</u>					
33	Secondary Voltage	12-1000 kemil Quad.	\$25,499	\$27,042		
34	Primary Voltage	---	---	---		---

<u>Index</u>		Escalation Factor
2021	2023	2021 - 2023
1.0406	1.1035	1.0605

	<u>Weighted %</u>
Residential Overhead % =	<u>57.6%</u>
% of Overhead Which Are Small Load=	53.0%
% of Overhead Which Are All Electric=	47.0%
Residential Underground % =	<u>42.4%</u>
% of Underground Which Are Small Load=	44.5%
% of Underground Which Are All Electric=	55.5%
Total OH & UG	100.0%

Meters 1

PacifiCorp  
Oregon Marginal Cost Study  
Weighted Average Installed Meter Costs  
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

Line	Load Class	(A) Customers	(% of Customers)			(E) Metering Cost	Weighted Metering Cost		
			(B)	(C)	(D)		(F)	(G)	(H)
			1 & 3 Phase (A) / (A,Ttl)	1 Phase (A) / 1Ø	3 Phase (A) / 3Ø		1 & 3 Phase (B) x (E)	1 Phase (C) x (E)	3 Phase (D) x (E)
1	Res - Schedule 4	519,723	100.00%	100.00%					
2	Annualized - (Line 1) x 6.97%				\$200	\$200.03	\$200.03		
3						\$13.94	\$13.94		
4	GS - Schedule 23								
5	0-15 kW								
6	kW = 0, 1 Phase	4,515	6.43%	7.95%	\$190	\$12.20	\$15.10		
7	kW = 0, 3 Phase	105	0.15%		\$310	\$0.46		\$2.41	
8	kW > 1, 1 Phase	52,248	74.40%	92.05%	\$190	\$141.23	\$174.73		
9	kW > 1, 3 Phase	13,359	19.02%		\$310	\$58.91		\$307.26	
10	Total 0-15 kW	70,227	100.00%	100.00%		\$212.80	\$189.83	\$309.67	
11	Annualized - (Line 10) x 6.97%					\$14.83	\$13.23	\$21.58	
12									
13	15+ kW								
14	1 Phase	7,878	54.35%	100.00%	\$190	\$103.17	\$189.83		
15	3 Phase W/O KVAR	3,485	24.05%		\$310	\$74.46		\$163.11	
16	3 Phase With KVAR	3,132	21.60%		\$310	\$66.90		\$146.56	
17	Total 15+ kW	14,495	100.00%	100.00%		\$244.53	\$189.83	\$309.67	
18	Annualized - (Line 17) x 6.97%					\$17.04	\$13.23	\$21.58	
19									
20	Primary								
21	12.47 KV 4-wire Wye	116	100.00%		\$10,032	\$10,032.33		\$10,032.33	
22	Annualized - (Line 21) x 6.97%					\$699.25	\$0.00	\$699.25	
23									
24	GS - Schedule 28								
25	0-50 kW								
26	kW = 0, 1 Phase	6	0.12%	0.42%	\$190	\$0.23	\$0.79		
27	kW = 0, 3 Phase	12	0.26%		\$310	\$0.81		\$1.14	
28	kW > 1, 1 Phase	1,362	28.76%	99.58%	\$190	\$54.59	\$189.04		
29	kW > 1, 3 Phase	3,356	70.86%		\$310	\$219.43		\$308.53	
30	Total 0-50 kW	4,736	100.00%	100.00%		\$275.06	\$189.83	\$309.67	
31	Annualized - (Line 30) x 6.97%					\$19.17	\$13.23	\$21.58	
32									
33	51-100 kW								
34	1 Phase	444	12.69%	100.00%	\$190	\$24.09	\$189.83		
35	3 Phase W/O KVAR	1,355	38.71%		\$310	\$119.86		\$137.28	
36	3 Phase With KVAR	1,701	48.60%		\$310	\$150.51		\$172.39	
37	Total 51-100 kW	3,501	100.00%	100.00%		\$294.46	\$189.83	\$309.67	
38	Annualized - (Line 37) x 6.97%					\$20.52	\$13.23	\$21.58	
39									
40	100 + kW								
41	1 Phase	31	1.56%	100.00%	\$1,098	\$17.16	\$1,097.62		
42	3 Phase W/O KVAR	761	38.51%		\$1,536	\$591.41		\$600.80	
43	3 Phase With KVAR	1,185	59.92%		\$1,536	\$920.18		\$934.80	
44	Total 100 + kW	1,977	100.00%	100.00%		\$1,528.75	\$1,097.62	\$1,535.60	
45	Annualized - (Line 44) x 6.97%					\$106.55	\$76.50	\$107.03	
46									
47	Primary								
48	12.47 KV 4-wire Wye	68	100.00%		\$10,032	\$10,032.33		\$10,032.33	
49	Annualized - (Line 48) x 6.97%					\$699.25	\$0.00	\$699.25	

Footnote:  
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2021.

Meters 2

PacifiCorp  
Oregon Marginal Cost Study  
Weighted Average Installed Meter Costs  
GS - Schedule 30 / LPS - Schedule 48 / Irrigation - Schedule 41 (Annual)

Line	Load Class	(A) Customers	% of Customers			(E) Metering Cost	Weighted Metering Cost		
			(B)	(C)	(D)		(F)	(G)	(H)
			(A) / (A,Tt)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	(D) x (E) (F) x 6.97%
1	GS - Schedule 30								
2	0-300 kW								
3	1 Phase	1	0.47%	100.00%	\$1,098	\$5.13	\$1,097.62		
4	3 Phase W/O KVAR	53	24.42%		\$1,536	\$374.99		\$376.75	
5	3 Phase With KVAR	163	75.11%		\$1,536	\$1,153.43		\$1,158.85	
6	Total 0-300 kW	217	100.00%	100.00%		\$1,533.55	\$1,097.62	\$1,535.60	
7	Annualized - (Line 6) x 6.97%					\$106.89	\$76.50	\$107.03	
8									
9	300+ kW								
10	1 Phase	0	0.00%	100.00%	\$1,360	\$0.00	\$1,359.56		
11	3 Phase W/O KVAR	112	20.77%		\$1,536	\$318.99		\$318.99	
12	3 Phase With KVAR	427	79.23%		\$1,536	\$1,216.62		\$1,216.62	
13	300+ kW	539	100.00%	100.00%		\$1,535.61	\$1,359.56	\$1,535.61	
14	Annualized - (Line 13) x 6.97%					\$107.03	\$94.76	\$107.03	
15									
16	Primary								
17	12.47 KV 4-wire Wye	53	100.00%	100.00%	\$10,032	\$10,032.33		\$10,032.33	
18	Annualized - (Line 17) x 6.97%					\$699.25		\$699.25	
19									
20	LPS - Schedule 48								
21	1 - 4 MW (sec)	93	100.00%	100.00%	\$1,859	\$1,859.06		\$1,859.06	
22	Annualized - (Line 21) x 6.97%					\$129.58		\$129.58	
23									
24	1 - 4 MW (pri)	61	100.00%	100.00%	\$10,032	\$10,032.33		\$10,032.33	
25	Annualized - (Line 24) x 6.97%					\$699.25		\$699.25	
26									
27	> 4 MW (sec)	1	100.00%	100.00%	\$1,859	\$1,859.06		\$1,859.06	
28	Annualized - (Line 27) x 6.97%					\$129.58		\$129.58	
29									
30	> 4 MW (pri)	28	100.00%	100.00%	\$10,032	\$10,032.33		\$10,032.33	
31	Annualized - (Line 30) x 6.97%					\$699.25		\$699.25	
32									
33	Trans (trn)	8	100.00%	100.00%	\$171,400	\$171,400.00		\$171,400.00	
34	Annualized - (Line 33) x 6.97%					\$11,946.58		\$11,946.58	
35									
36									
37	Irrigation - Schedule 41 (Annual)								
38	0 - 50 kW								
39	kW = 0, 1 Phase	-	0.00%	0.00%	\$190	\$0.00	\$0.00		
40	kW = 0, 3 Phase	-	0.00%	0.00%	\$310	\$0.00		\$0.00	
41	kW > 1, 1 Phase	1,017	15.49%	99.90%	\$190	\$29.40	\$189.64		
42	kW > 1, 3 Phase	4,558	69.39%		\$310	\$214.88		\$254.30	
43									
44	51 - 300 kW								
45	1 Phase	1	0.02%	0.10%	\$190	\$0.03	\$0.19		
46	3 Phase W/O KVAR	124	1.89%		\$310	\$5.85		\$6.92	
47	3 Phase With KVAR	850	12.94%		\$310	\$40.07		\$47.42	
48									
49	> 300 kW								
50	1 Phase	-	0.00%	0.00%	\$1,360	\$0.00	\$0.00		
51	3 Phase W/O KVAR	3	0.05%		\$1,536	\$0.76		\$0.90	
52	3 Phase With KVAR	15	0.23%		\$1,536	\$3.57		\$4.23	
53	Total Irrigation	6,569	100.00%	100.00%		\$294.56	\$189.83	\$313.77	
54						\$20.53	\$13.23	\$21.87	
55									
56	Primary	3	100.00%	100.00%	\$0	\$0.00	\$0.00	\$0.00	
57						\$0.00	\$0.00	\$0.00	

Footnote:  
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2021.



Meters 3

PacifiCorp  
Oregon Marginal Cost Study  
Incremental Three Phase  
Meter and Services Costs

Line	Load Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Meters				Service Drops			
		Single Phase	Three Phase	Difference	Annualized Difference	Single Phase	Three Phase	Difference	Annualized Difference
		(B) - (A)		(C) x 6.97%			(F) - (E)	(G) x 6.97%	
1	Residential	\$200.03	\$309.67	\$109.64	\$7.64	\$749.32	\$1,139.22	\$389.90	\$27.18
2									
3	0-15 kW	\$189.83	\$309.67	\$119.84	\$8.35	\$969.82	\$1,226.69	\$256.87	\$17.90
4									
5	16-100 kW	\$189.83	\$309.67	\$119.84	\$8.35	\$1,735.61	\$2,233.85	\$498.24	\$34.73
6									
7	101-1000 kW	\$1,359.56	\$1,535.60	\$176.04	\$12.27	\$4,064.47	\$4,108.64	\$44.18	\$3.08
8									
9	1 - 4 MW	N.A.	\$1,859.06	N.A.	N.A.	N.A.	\$27,041.69	N.A.	N.A.

Meters 4

PacifiCorp  
Oregon Marginal Cost Study  
Summary of Average Installed Costs  
Meters

Line	Load Class	(A) Metering Standard	(B) Meter Cost in 2021 Dollars	(C) Indexed to 2023	(D) Percent Use	(E) Total Installed Cost per Meter
	<u>Residential</u>					
1	Small Load	DM221J	\$179.00	189.8295	49.39%	93.76611809
2	All Electric	DM221K	\$198.00	\$209.98	50.61%	\$106.26
3					100.00%	\$200.03
4						
5	<u>0 - 15 kW</u>					
6	kW = 0, 1 Phase	DM221J	\$179.00	\$189.83	100.00%	\$189.83
7						
8	kW = 0, 3 Phase	DM241D	\$292.00	\$309.67	100.00%	\$309.67
9						
10	kW > 1, 1 Phase	DM221J	\$179.00	\$189.83	100.00%	\$189.83
11						
12	kW > 1, 3 Phase	DM241D	\$292.00	\$309.67	100.00%	\$309.67
13						
14						
15	<u>15 - 100 kW</u>					
16	1 Phase	DM221J	\$179.00	\$189.83	100.00%	\$189.83
17						
18	3 Phase wo / KVAR	DM241D	\$292.00	\$309.67	100.00%	\$309.67
19						
20	3 Phase with KVAR	DM241D	\$292.00	\$309.67	100.00%	\$309.67
21						
22						
23	<u>100 - 300 kW</u>					
24	1 Phase	DM231FBB	\$1,035.00	\$1,097.62	100.00%	\$1,097.62
25						
26	3 Phase wo / KVAR	DM271DEC	\$1,448.00	\$1,535.60	100.00%	\$1,535.60
27						
28	3 Phase with KVAR	DM271DEC	\$1,448.00	\$1,535.60	100.00%	\$1,535.60
29						
30						
31	<u>300-1000 kW</u>					
32	W/O KVAR, 1 Phase	DM231FFE	\$1,282.00	\$1,359.56	100.00%	\$1,359.56
33						
34	W/O KVAR, 3 Phase	DM271DEC	\$1,448.00	\$1,535.60	100.00%	\$1,535.60
35						
36	W/KVAR, 3 Phase	DM271DEC	\$1,448.00	\$1,535.60	100.00%	\$1,535.60
37						
38						
39	<u>1000 kW and over</u>					
40	Secondary Volt	DM271AEG	\$1,753.00	\$1,859.06	100.00%	\$1,859.06
41						
42	<u>Primary Metering</u>					
43	13.8 KV 3-wire	DM101ACBA	\$8,022.00	\$8,507.33		\$8,507.33
44	12.47 KV 4-wire Wye	DM121ACJAD	\$9,460.00	\$10,032.33		\$10,032.33
45	24.9 KV 4-wire Wye	DM121BFIAD	\$13,387.00	\$14,196.91		\$14,196.91
46	35 KV 4-wire Wye	DM131BBAH	\$15,302.00	\$16,227.77		\$16,227.77

	<u>Index</u>		Escalation Factor
	<u>2021</u>	<u>2023</u>	<u>2021 - 2023</u>
	1.0406	1.1035	1.0605

Meters 5

PacifiCorp  
Oregon Marginal Cost Study  
Distribution Meters Expense  
Loading Factor

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
Line	Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	<u>Distribution Meters Expenses</u>										
1	586 Meter Expense	3,548,094	3,194,944	2,991,325	3,120,160	2,616,262	1,645,292	1,079,103	883,546	655,758	1,279,281
2	597 Main. of Meters	1,386,968	1,556,466	1,628,742	1,653,908	1,198,881	10,098	59,787	85,408	231,001	235,870
3											
4	Total Adjusted Distribution Meters Expense	4,935,062	4,751,410	4,620,067	4,774,068	3,815,143	1,655,390	1,138,890	968,955	886,759	1,515,150
5	Line 1 + Line 2										
6											
7											
8											
9	<u>Distribution Meters</u>										
10	370 Meters	59,771,898	59,665,589	59,706,364	60,110,283	60,993,623	62,541,755	65,791,804	76,927,946	90,849,203	96,302,523
11											
12											
13											
14	<u>Meters Expense Loading Factor</u>										
15	Meter O&M Loading	8.26%	7.96%	7.74%	7.94%	6.25%	2.65%	1.73%	1.26%	0.98%	1.57%
16	Line 4 / Line 10										
17											
18	Average Meter O&M Loading	4.63%									
19	Average of Line 15										
20											
21	Distribution Annual Charge	6.97%									
22											
23	Annualized Meter O&M Loading Factor	66.49%									
24	Line 18 / Line 21										

PacificCorp  
Oregon Marginal Cost Study  
Street, Area, and Recreational Lighting  
Full Marginal Cost by Schedule

Line	Units Description / Function	Company Owned															Customer Owned				
		Schedule 51															Schedule 15			Schedule 53	Schedule 54
		Level 1 (0-3,500 LED Equivalent Lumens)	Level 2 (3,501-5,500 LED Equivalent Lumens)	Level 3 (5,501-8,000 LED Equivalent Lumens)	Level 4 (8,001-12,000 LED Equivalent Lumens)	Level 5 (12,001-15,500 LED Equivalent Lumens)	Level 6 (15,501 and Greater LED Equivalent Lumens)	Dec Series Level 2 (3,501-5,500 LED Equivalent Lumens)	Dec Series Level 3 (5,501-8,000 LED Equivalent Lumens)	Cust. Funded Conv. - Level 1 (0-3,500 LED Equivalent Lumens)	Cust. Funded Conv. - Level 2 (3,501-5,500 LED Equivalent Lumens)	Cust. Funded Conv. - Level 3 (5,501-8,000 LED Equivalent Lumens)	Cust. Funded Conv. - Level 4 (8,001-12,000 LED Equivalent Lumens)	Cust. Funded Conv. - Level 5 (12,001-15,500 LED Equivalent Lumens)	Cust. Funded Conv. - Level 6 (15,501 and Greater LED Equivalent Lumens)	Level 1 (0-5,500 LED Equivalent Lumens)	Level 2 (5,501-12,000 LED Equivalent Lumens)	Level 3 (12,001 and Greater LED Equivalent Lumens)			
1	Average Annual Lamps	8,761	13,590	1,505	4,413	1,361	1,139	112	16	321	3,248	1,388	216	312	39	5,694	1,401	348			
2	Avg Lamp kW @ Input	0.042	0.054	0.081	0.093	0.146	0.201	0.054	0.081	0.042	0.054	0.081	0.093	0.146	0.201	0.043	0.108	0.163			
3	Peak kW @ Input-Distribution																		19	27	
4	Peak kW @ Input-Transformer																		2,886	5,254	
5	Peak kW @ Input-System																		668	309	
6																					
7	Annual kWh @ Sales	876,058	2,487,016	445,579	1,822,500	714,481	783,403	20,572	4,637	32,067	594,369	410,971	89,242	163,844	26,660	1,269,706	578,407	239,653	11,451,780	1,141,242	
8	Monthly kWh Usq @ Sales per Lamp	8	15	25	34	44	57	15	25	8	15	25	34	44	57	19	34	57			
9	Losses	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	1,0797	
10	Annual kWh @ Input	945,836	2,685,107	481,069	1,967,662	771,390	845,801	22,211	5,007	34,621	641,710	443,705	96,351	176,894	28,783	1,370,838	624,477	258,742	12,363,914	1,232,142	
11	Monthly kWh Usq @ Input per Lamp	9	16	27	37	47	62	16	27	9	16	27	37	47	62	20	37	62			
12																					
13																					
14	Gen \$/kWh @ Input	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	\$0.03532	
15	Transn \$/kWh @ Input	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	\$0.00000	
16																					
17	Generation (\$/kW)	\$93.29	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	\$93.29000	
18																					
19	Transmission (\$/kW)	\$4.38	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	\$4.38000	
20																					
21																					
22	Distribution-Poles (\$/kW)	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	\$24.61	
23	Index	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	
24	Revised Distribution-Poles, incl. Annualization @ 6.97% (\$/kW)	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	\$26.10	
25																					
26	Distribution-Conductor (\$/kW)	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	\$32.91	
27	Index	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	
28	Revised Distribution-Conductor, incl. Annualization @ 6.97% (\$/kW)	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	\$34.89	
29																					
30	Distribution-Transformer (\$/kW)	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$8.23	\$13.84	\$13.84	
31	Index	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	
32	Revised Distribution-Transformer, incl. Annualization @ 6.97% (\$/kW)	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$8.73	\$1.48	\$1.48	
33																					
34	Distribution-Lighting - Installations	\$969.94	\$1,035.60	\$1,040.07	\$1,049.54	\$1,107.58	\$1,347.79	\$2,960.67	\$2,960.67	\$2,960.67	\$2,960.67	\$2,960.67	\$2,960.67	\$2,960.67	\$2,960.67	\$847.54	\$941.52	\$1,092.52			
35	Index	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	
36	Revised Distribution-Lighting Installations, incl. Annualization @ 6.97%	\$71.69	\$76.55	\$76.88	\$77.58	\$81.87	\$99.62	\$218.83	\$218.83	\$218.83	\$218.83	\$218.83	\$218.83	\$218.83	\$218.83	\$62.64	\$69.59	\$80.75			
37																					
38	Distribution-Lighting O&M	\$77.83	\$81.12	\$81.34	\$81.81	\$83.81	\$100.76	\$59.04	\$59.04	\$77.83	\$81.12	\$81.34	\$81.81	\$83.81	\$100.76	\$40.93	\$44.69	\$51.45			
39	Index	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	
40	Revised Distribution-Lighting O&M	\$82.54	\$86.02	\$86.26	\$86.76	\$88.87	\$106.85	\$62.61	\$62.61	\$82.54	\$86.02	\$86.26	\$86.76	\$88.87	\$106.85	\$43.41	\$47.39	\$54.56			
41																					
42	<b>Monthly Cost Per Company-Owned Lamp</b>																				
43	Generation Energy	\$0.32	\$0.58	\$0.94	\$1.31	\$1.67	\$2.19	\$0.58	\$0.94	\$0.32	\$0.58	\$0.94	\$1.31	\$1.67	\$2.19	\$0.71	\$1.31	\$2.19			
44	Transmission Energy	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00			
45																					
46	Generation Demand	\$0.04	\$0.08	\$0.12	\$0.17	\$0.22	\$0.29	\$0.08	\$0.12	\$0.04	\$0.08	\$0.12	\$0.17	\$0.22	\$0.29	\$0.09	\$0.17	\$0.29			
47	Transmission Demand	\$0.00	\$0.00	\$0.01	\$0.01	\$0.01	\$0.01	\$0.00	\$0.01	\$0.00	\$0.00	\$0.01	\$0.01	\$0.01	\$0.01	\$0.00	\$0.01	\$0.01			
48																					
49	Distribution-Poles	\$0.09	\$0.12	\$0.18	\$0.20	\$0.32	\$0.44	\$0.12	\$0.18	\$0.09	\$0.12	\$0.18	\$0.20	\$0.32	\$0.44	\$0.09	\$0.23	\$0.35			
50	Distribution-Conductor	\$0.12	\$0.16	\$0.24	\$0.27	\$0.43	\$0.58	\$0.16	\$0.24	\$0.12	\$0.16	\$0.24	\$0.27	\$0.43	\$0.58	\$0.13	\$0.31	\$0.47			
51	Distribution-Transformer	\$0.03	\$0.04	\$0.06	\$0.07	\$0.11	\$0.15	\$0.04	\$0.06	\$0.03	\$0.04	\$0.06	\$0.07	\$0.11	\$0.15	\$0.03	\$0.08	\$0.12			
52																					
53	Distribution-Lighting	\$12.85	\$13.55	\$13.59	\$13.69	\$14.23	\$17.21	\$23.45	\$23.45	\$6.88	\$7.17	\$7.19	\$7.23	\$7.41	\$8.90	\$8.84	\$9.75	\$11.28			
54																					
55	Customer - Billing	\$0.07	\$0.07	\$0.07	\$0.07	\$0.07	\$0.07	\$0.07	\$0.07	\$0.07	\$0.07	\$0.07	\$0.07	\$0.07	\$0.07	\$1.74	\$1.74	\$1.74			
56	Customer - Metering	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00			
57	Customer - Other	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.58	\$0.58	\$0.58			
58	<b>Total Lighting Marginal Cost</b>																				
59	Generation Energy	\$33,407	\$94,838	\$16,991	\$69,498	\$27,245	\$29,874	\$784	\$1,177	\$1,223	\$22,665	\$15,672	\$3,403	\$6,248	\$1,017	\$48,418	\$22,057	\$9,139	\$436,693	\$43,519	
60	Transmission Energy	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
61																					
62	Generation Demand	\$4,394	\$12,474	\$2,235	\$9,141	\$3,584	\$3,929														

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PacifiCorp  
Oregon Marginal Cost Study  
Street, Area, and Recreational Lighting  
Customer Cost Development by Schedule

Line	Calculation Component	Units Description / Function	Schedule			
			51	15	53	54
1	Units	Average Customers	1,108	5,809	314	102
2						
3						
4	\$/Unit	Meters				\$24.69
5	\$/Unit	Billing	\$26.77	\$26.77	\$26.77	\$26.77
6	\$/Unit	Meter Reading	\$0.00	\$0.00	\$0.00	\$0.00
7	\$/Unit	Customer Service / Other	\$8.97	\$8.97	\$8.97	\$8.97
8						
9						
10	\$	Meters				\$2,518
11	\$	Billing	\$29,661	\$155,517	\$8,406	\$2,731
12	\$	Meter Reading	\$0	\$0	\$0	\$0
13	\$	Customer Service / Other	\$9,937	\$52,101	\$2,816	\$915
14						
15						
16	Units	Forecast Average Annual Lamps	36,421	7,443		
17						
18						
19	\$/Unit	Billing / Forecast Average Annual Lamps	\$0.81	\$20.90		
20	\$/Unit	Meter Reading / Forecast Average Annual Lamps	\$0.00	\$0.00		
21	\$/Unit	Customer Service / Other / Forecast Average Annual Lamps	\$0.27	\$7.00		

Company-Owned LED Lighting Maintenance Costs

			<u>Street Lights</u>								<u>Area Lights</u>		
			Level 1 (0-3,500 LED Equivalent Lumens)	Level 2 (3,501-5,500 LED Equivalent Lumens)	Level 3 (5,501-8,000 LED Equivalent Lumens)	Level 4 (8,001-12,000 LED Equivalent Lumens)	Level 5 (12,001-15,500 LED Equivalent Lumens)	Level 6 (15,501 and Greater LED Equivalent Lumens)	Decorative Series - Level 2 (3,501-5,500 LED Equivalent Lumens)	Decorative Series - Level 3 (5,501-8,000 LED Equivalent Lumens)	Level 1 (0-5,500 LED Equivalent Lumens)	Level 2 (5,501-12,000 LED Equivalent Lumens)	Level 3 (12,001 and Greater LED Equivalent Lumens)
Hours	Rate												
Replace Pole (wood)			30'	30'	30'	30'	35'	40'			30'	30'	35'
	\$183.56												
			\$472.65	\$472.65	\$472.65	\$472.65	\$562.52	\$690.70			\$472.65	\$472.65	\$562.52
Labor	7.80	2 man	\$1,431.78	\$1,431.78	\$1,431.78	\$1,431.78	\$1,431.78	\$1,431.78			\$1,431.78	\$1,431.78	\$1,431.78
Total Cost			\$1,904.43	\$1,904.43	\$1,904.43	\$1,904.43	\$1,994.30	\$2,122.48			\$1,904.43	\$1,904.43	\$1,994.30
Annual Frequency			0.011	0.011	0.011	0.011	0.011	0.011			0.008	0.008	0.008
Annual Cost			\$21.33	\$21.33	\$21.33	\$21.33	\$22.34	\$23.77			\$15.24	\$15.24	\$15.95
Replace Pole and arm (metal)			25'	25'	25'	25'	30'	35'	25'	25'			
			\$652.07	\$652.07	\$652.07	\$652.07	\$1,285.45	\$2,251.84	\$665.60	\$665.60			
Labor	6.90	2 man	\$1,266.57	\$1,266.57	\$1,266.57	\$1,266.57	\$1,266.57	\$1,266.57	\$1,266.57	\$1,266.57			
Total Cost			\$1,918.64	\$1,918.64	\$1,918.64	\$1,918.64	\$2,552.02	\$3,518.41	\$1,932.17	\$1,932.17			
Annual Frequency			0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004			
Annual Cost			\$9.29	\$9.29	\$9.29	\$9.29	\$12.36	\$17.04	\$6.76	\$6.76			
Replace Fiberglass Pole			30'	30'	30'	30'	35'	40'					
			\$788.32	\$788.32	\$788.32	\$788.32	\$948.83	\$1,194.55					
Labor	6.20	2 man	\$1,138.08	\$1,138.08	\$1,138.08	\$1,138.08	\$1,138.08	\$1,138.08					
Total Cost			\$1,926.40	\$1,926.40	\$1,926.40	\$1,926.40	\$2,086.90	\$2,332.63					
Annual Frequency			0.005	0.005	0.005	0.005	0.005	0.005					
Annual Cost			\$9.63	\$9.63	\$9.63	\$9.63	\$10.43	\$11.66					
Replace Mast Arm													
			\$217.13	\$217.13	\$217.13	\$217.13	\$217.13	\$217.13			\$165.19	\$165.19	\$165.19
Labor	2.20	2 man	\$403.83	\$403.83	\$403.83	\$403.83	\$403.83	\$403.83			\$403.83	\$403.83	\$403.83
Total Cost			\$620.96	\$620.96	\$620.96	\$620.96	\$620.96	\$620.96			\$569.03	\$569.03	\$569.03
Annual Frequency			0.013	0.013	0.013	0.013	0.013	0.013			0.006	0.006	0.006
Annual Cost			\$8.07	\$8.07	\$8.07	\$8.07	\$8.07	\$8.07			\$3.41	\$3.41	\$3.41
Replace Photo Cell													
			\$20.92	\$20.92	\$20.92	\$20.92	\$20.92	\$20.92	\$20.92	\$20.92	\$20.92	\$20.92	\$20.92
Labor	0.70	Single man	\$128.49	\$128.49	\$128.49	\$128.49	\$128.49	\$128.49	\$128.49	\$128.49	\$128.49	\$128.49	\$128.49
Total Cost			\$149.41	\$149.41	\$149.41	\$149.41	\$149.41	\$149.41	\$149.41	\$149.41	\$149.41	\$149.41	\$149.41
Annual Frequency			0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Annual Cost			\$7.47	\$7.47	\$7.47	\$7.47	\$7.47	\$7.47	\$7.47	\$7.47	\$7.47	\$7.47	\$7.47
Replace Luminaire													
			\$220.48	\$286.14	\$290.61	\$300.08	\$358.12	\$598.33	\$900.00	\$900.00	\$150.02	\$244.00	\$395.00
Labor	1.20	Single man	\$220.27	\$220.27	\$220.27	\$220.27	\$220.27	\$220.27	\$220.27	\$220.27	\$220.27	\$220.27	\$220.27
Total Cost			\$440.75	\$506.42	\$510.88	\$520.35	\$578.39	\$818.60	\$1,120.27	\$1,120.27	\$370.29	\$464.27	\$615.27
Annual Frequency			0.050	0.050	0.050	0.050	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Annual Cost			\$22.04	\$25.32	\$25.54	\$26.02	\$23.14	\$32.74	\$44.81	\$44.81	\$14.81	\$18.57	\$24.61
Total Annual Maintenance			\$77.83	\$81.12	\$81.34	\$81.81	\$83.81	\$100.76	\$59.04	\$59.04	\$40.93	\$44.69	\$51.45
Total Monthly Maintenance			\$6.49	\$6.76	\$6.78	\$6.82	\$6.98	\$8.40	\$4.92	\$4.92	\$3.41	\$3.72	\$4.29
Total Installation Cost per Lamp			\$969.94	\$1,035.60	\$1,040.07	\$1,049.54	\$1,107.58	\$1,347.79	\$2,960.67	\$2,960.67	\$847.54	\$941.52	\$1,092.52

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LED Usage Amounts & Area Light Counts by Type

Street and Area Light Energy Consumption by Level of Service				
Street/Area	Level	Annual kWh	Watts	
Street	Level 1 (0-3,500 LED Equivalent Lumens)	100	39	
Street	Level 2 (3,501-5,500 LED Equivalent Lumens)	183	50	
Street	Level 3 (5,501-8,000 LED Equivalent Lumens)	296	75	
Street	Level 4 (8,001-12,000 LED Equivalent Lumens)	413	86	
Street	Level 5 (12,001-15,500 LED Equivalent Lumens)	525	135	
Street	Level 6 (15,501 and Greater LED Equivalent Lumens)	688	185	
Street	Dec Series Level 2 (3,501-5,500 LED Equivalent Lumens)	183	50	
Street	Dec Series Level 3 (5,501-8,000 LED Equivalent Lumens)	296	75	
Street	Cust. Funded Conv. - Level 1 (0-3,500 LED Equivalent Lumens)	100	39	
Street	Cust. Funded Conv. - Level 2 (3,501-5,500 LED Equivalent Lumens)	183	50	
Street	Cust. Funded Conv. - Level 3 (5,501-8,000 LED Equivalent Lumens)	296	75	
Street	Cust. Funded Conv. - Level 4 (8,001-12,000 LED Equivalent Lumens)	413	86	
Street	Cust. Funded Conv. - Level 5 (12,001-15,500 LED Equivalent Lumens)	525	135	
Street	Cust. Funded Conv. - Level 6 (15,501 and Greater LED Equivalent Lumens)	688	185	
Area	Level 1 (0-5,500 LED Equivalent Lumens)	223	40	
Area	Level 2 (5,501-12,000 LED Equivalent Lumens)	413	99	
Area	Level 3 (12,001 and Greater LED Equivalent Lumens)	688	150	

Cust Exp Year

PacifiCorp  
Oregon Marginal Cost Study  
Summary of Customer and Metering Expenses  
December 2023 Dollars

Line	Description	(A) Actual 2016 Dollars	(B) Actual 2017 Dollars	(C) Actual 2018 Dollars	(D) Actual 2019 Dollars	(E) Actual 2020 Dollars	(F) Adjusted 2023 Dollars
							[(A) x 1.1731+ (B) x 1.1467+ (C) x 1.1208+ (D) x 1.0955+ (E) x 1.0708 ] / 5
	<u>Customer Accounting</u>						
1	901 Supervision	737,727	744,030	776,328	712,826	706,833	\$825,298
2	902 Meter Reading Expense	9,736,750	10,573,506	9,772,620	4,869,243	2,245,673	\$8,447,779
3	903 Cust Records & Collection	15,397,727	15,201,207	15,706,759	15,074,984	13,295,839	\$16,770,053
4	904 Uncollectible Accounts	4,289,333	6,179,088	4,639,879	5,061,708	6,263,999	\$5,914,069
5	905 Misc Cust Acct Expense	12,890	3,926	4,809	5,606	8,479	\$8,047
6	Total	30,174,427	32,701,757	30,900,395	25,724,366	22,520,822	\$31,965,246
7							
8	<u>Customer Service &amp; Info Expense</u>						
9	907 Supervision	88,021	90,935	36,862	2,105	208	\$50,275
10	908 Cust Assistance Expense	2,697,239	2,512,406	2,730,139	3,325,682	3,466,926	\$3,292,143
11	909 Info & Instructional Expense	887,624	857,417	2,077,877	2,316,089	1,879,350	\$1,780,608
12	910 Misc Cust Svc & Info Expense	17,342	1,002	12,955	1,416	541	\$7,629
13	Total	3,690,225	3,461,760	4,857,833	5,645,291	5,347,026	\$5,130,655
14							\$37,095,901
15	<u>Distribution Expenses</u>						
16	586 Meter Expenses	\$1,645,292	\$1,079,103	\$883,546	\$655,758	\$1,279,281	\$1,249,203
17	597 Meter Maintenance	\$10,098	\$59,787	\$85,408	\$231,001	\$235,870	\$136,352
18		\$1,655,390	\$1,138,890	\$968,955	\$886,759	\$1,515,150	\$1,385,555
19							
20							
21	(1) Inflation Adjustment -	1.1731	1.1467	1.1208	1.0955	1.0708	

Source:

Source: State of Oregon results of operations



PacifiCorp  
Oregon Marginal Cost Study  
Summary of Customer Accounting Expense  
By Schedule  
December 2023 Dollars

Line	FERC Account	Description	Calculation Description	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
				Sch. 4 Residential	Sch. 23 General Service	Sch. 28 General Service	Sch. 30 General Service	Sch. 48 General Service	Sch. 41 Irrigation	Streetlighting	Total
1			Average Number of Customers	535,059	84,332	10,462	797	190	4,356	7,333	642,529
2			Write-offs By Schedule	2,229,536	90,828	113,220	51,212	57,250	15,617	-	2,557,663
3											
4											
5	901	Supervision	Account 902 + 903 + 904	\$18,585,837	\$2,769,465	\$630,165	\$146,479	\$187,628	\$168,232	\$196,315	\$22,684,122
6	901		% of Total 902 + 903 + 904	81.93%	12.21%	2.78%	0.65%	0.83%	0.74%	0.87%	100.00%
7	901		Total 901 \$	\$676,193	\$100,759	\$22,927	\$5,329	\$6,826	\$6,121	\$7,142	\$825,298
8	901		\$ Per Customer	\$1.26	\$1.19	\$2.19	\$6.69	\$35.93	\$1.41	\$0.97	\$1.28
9											
10	902	Meter Reading Expense	902 Weighting Factor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
11	902		Weighted Customers	0	0	0	0	0	0	0	0
12	902		% of Total \$	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	902		Total 902 \$	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14	902		\$ Per Customer	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
15											
16	903	Cust. Receipts & Collect.	903 Weighting Factor	1.00	1.21	1.40	1.40	11.58	1.21	1.07	
17	903		Weighted Customers	535,059	101,966	14,675	1,118	2,201	5,264	7,821	668,104
18	903		% of Total \$	80.09%	15.26%	2.20%	0.17%	0.33%	0.79%	1.17%	100.00%
19	903		Total 903 \$	\$13,430,494	\$2,559,445	\$368,367	\$28,062	\$55,249	\$132,121	\$196,315	\$16,770,053
20	903		\$ Per Customer	\$25.10	\$30.35	\$35.21	\$35.21	\$290.78	\$30.33	\$26.77	\$26.10
21											
22	904	Uncollectibles	Total 904 \$	\$5,155,343	\$210,020	\$261,798	\$118,417	\$132,380	\$36,111	\$0	\$5,914,069
23	904		% of Write-offs	87.17%	3.55%	4.43%	2.00%	2.24%	0.61%	0.00%	100.00%
24	904		\$ Per Customer	\$9.64	\$2.49	\$25.02	\$148.58	\$696.73	\$8.29	\$0.00	\$9.20
25											
26	905	Misc Cust Acct Expense	Account 902 + 903 + 904	\$18,585,837	\$2,769,465	\$630,165	\$146,479	\$187,628	\$168,232	\$196,315	\$22,684,122
27	905		% of Total 902 + 903 + 904	81.93%	12.21%	2.78%	0.65%	0.83%	0.74%	0.87%	100.00%
28	905		Total 905 \$	\$6,593	\$982	\$224	\$52	\$67	\$60	\$70	\$8,047
29	905		\$ Per Customer	\$0.01	\$0.01	\$0.02	\$0.07	\$0.35	\$0.01	\$0.01	\$0.01
30											
31	907-910	Supervision, Cust. Assist.	Average Number of customers	535,059	84,332	10,462	797	190	4,356	7,333	642,529
32	907-910	Info & Instructional Exp.,	% of Total	83.27%	13.13%	1.63%	0.12%	0.03%	0.68%	1.14%	100.00%
33	907-910	Misc Cust Svc & Info Exp.	Total 907-910 \$	\$4,272,495	\$673,399	\$83,540	\$6,364	\$1,517	\$34,783	\$58,557	\$5,130,655
34	907-910		\$ Per Customer	\$7.99	\$7.99	\$7.99	\$7.99	\$7.99	\$7.99	\$7.99	\$7.99
35											
36											
37	901 - 910		Total 901 - 910 \$	\$23,541,118	\$3,544,606	\$736,855	\$158,225	\$196,038	\$209,195	\$262,085	\$28,648,122
38											
39			\$ Per Customer	\$44.00	\$42.03	\$70.43	\$198.53	\$1,031.78	\$48.02	\$35.74	\$44.59

AG Expenses

PacifiCorp  
Oregon Marginal Cost Study  
Administrative & General Expense  
Loading Factor

Year	(A)	(B)	(C)
	Administrative and General Expenses (000)	Electric Plant in Service (000)	Admin. & General to Electric Plant In Service Loading Factor (A) / (B)
2011	\$152,657	\$22,769,524	0.67%
2012	\$188,240	\$23,734,237	0.79%
2013	\$175,800	\$24,578,893	0.72%
2014	\$103,887	\$25,826,088	0.40%
2015	\$134,217	\$26,518,617	0.51%
2016	\$129,633	\$27,064,435	0.48%
2017	\$142,110	\$27,658,984	0.51%
2018	\$135,363	\$28,221,394	0.48%
2019	\$123,137	\$28,629,755	0.43%
2020	\$291,921	\$30,542,983	0.96%
10 Year Average A&G to EPIS Loading Factor			0.60%

Footnotes:

(A) FERC Form 1 Page 323, line 197

(B) FERC Form 1 Page 207, line 104

Charge 1

PacifiCorp  
Oregon Marginal Cost Study  
Calculation of Annual Charges

Line	Description	(A)	(B)	(C)	(D)	(E)
		20 years - Generation	10 years - Generation	5 years - Generation	System Transmission	Distribution
1	Levelized Income Taxes	NA	NA	NA	1.05%	0.97%
2	Levelized Property Tax	NA	NA	NA	0.67%	0.64%
3	Total	NA	NA	NA	1.72%	1.61%
4						
5	Levelized Income & Property Taxes	NA	NA	NA	\$17.20	\$16.10
6	(per \$1,000 of Investment)					
7						
8	Expected Life	20	10	5	65	53
9						
10	Nominal Interest Rate	7.21%	7.21%	7.21%	7.21%	7.21%
11						
12	Present Value: Income **	NA	NA	NA	\$235.91	\$217.66
13	Taxes & Property Taxes per				(PV of \$17.20 per year	(PV of \$16.10 per year
14	\$1,000 of Investment				for 65 years at 7.21%)	for 53 years at 7.21%)
15						
16	Removal Cost Per \$1,000 Investment				\$179.96	\$442.52
17						
18	Present Value: Removal Cost				\$1.95	\$11.04
19	at End of Useful Life				(PV of \$179.96 in	(PV of \$442.52 in
20					65 years at 7.21%)	53 years at 7.21%)
21						
22	Investment and Taxes	\$1,000.00	\$1,000.00	\$1,000.00	\$1,237.86	\$1,228.70
23	w/o PVCD (Line 12 + Line 18 + \$1000)					
24						
25	PVCD Factor	NA	NA	NA	0.035405	0.038044
26						
27	PVCD \$ (Line 22 x Line 25)	NA	NA	NA	\$43.83	\$46.75
28						
29	Total (Line 22 + Line 27)	\$1,000.00	\$1,000.00	\$1,000.00	\$1,281.69	\$1,275.45
30						
31	EOY Annual Charge ***	\$75.24	\$122.35	\$219.16	\$61.57	\$63.67
32						
33	Annual Economic Carrying	7.52%	12.24%	21.92%	6.16%	6.37%
34	Adm & Gen Expense Loading Factor	0.00%	0.00%	0.00%	0.60%	0.60%
35						
36	Annual Econ Carrying + A&G Loading	7.52%	12.24%	21.92%	6.76%	6.97%

Footnotes:

From Financial Analysis -

\*\*  $PV = Ln(5) \times [1/r - (1/r)/(1+r)^a]$

$$17.20 \times (1/0.0721 - (1/0.0721)/(1+0.0721)^{65})$$

$$16.10 \times (1/0.0721 - (1/0.0721)/(1+0.0721)^{53})$$

Where:

r = Nominal Interest Rate

a = Expected Investment Life

\*\*\* The Annual Charge Formula:

$$AC\% = Ln(11) \times k \times \{1/[1 - 1/(1+k)^a]\}/(1+k)$$

Where:

k = real interest rate =  $(1 + r) / (1 + i) - 1$

i = inflation rate = 2.3%

a = expected investment life

r = nominal interest rate

Charge 2

PacifiCorp  
Oregon Marginal Cost Study  
Financial Inputs to the Economic Carrying Charge Calculation

	(A)	(B)	(C)	(D)	(E)	(F)
Line	Financial Inputs		Levelized		Weighted Inflation Rate	
1	Weighted Cost of Capital	7.21%	Income Taxes		2021	4.06%
2	Borrowing Rate	7.21%	Transmission	1.05%	2022	3.68%
3	Inflation	2.31%	Distribution	0.97%	2023	2.28%
4			Property Taxes		2024	2.43%
5	Real Cost of Capital		Transmission	0.67%	2025	2.43%
6	$(1+0.0721)/(1+0.0231)-1 =$	4.79%	Distribution	0.64%	2026	2.36%
7					2027	2.38%
8					2028	2.38%
9					2029	2.36%
10					2030	2.31%
11					2031	2.29%
12					2032	2.23%
13					2033	2.25%
14					2034	2.26%
15					2035	2.27%
16					2036	2.26%
17					2037	2.27%
18					2038	2.27%
19					2039	2.27%
20					2040	2.28%
21					2041	2.27%
22					2042	2.29%
23					2023 thru 2042 Average	2.31%

Source:

Cost of Capital/Borrowing Rate: Revenue Requirement (OR Jurisdictional Allocation Model)

Income & Property Taxes: 2021 Use of Facilities Report

Company Official Inflation Rate Forecast, 4th Quarter 2021

PacifiCorp  
 Oregon Marginal Cost Study  
 Present Value of Cost of Dispersion Factor  
 Iowa Curve R 2 & 65 Year Average Life  
 Page 1 of 2

Real Cost of Capital = 4.79%

YEAR	(A) PVCD	(B) % RENEWED	(C) NUM1	(D) DEM1	(E) NUM1/DEM1	(F) NUM2	(G) DEM2	(H) NUM2/DEM2	(I) INSTANCE	(J) Iowa R 2.0
	((A) {yr-1} + (I) ) / 100	((J, {yr-1}) - (J)) * 100	(B)	1.0479 ^Year	(C) / (D)	(B)	1.0479 ^62	(F) / (G)	(E) - (H)	(Given)
1	0.000703	7.82%	0.0782	1.047944	0.074578	0.0782	18.237317	0.004285	0.070293	100.0000
2	0.002041	15.63%	0.1563	1.098187	0.142333	0.1563	18.237317	0.008571	0.133762	99.9218
3	0.003313	15.63%	0.1563	1.150838	0.135821	0.1563	18.237317	0.008571	0.127250	99.7655
4	0.004577	16.32%	0.1632	1.206014	0.135347	0.1632	18.237317	0.008950	0.126397	99.6092
5	0.005932	18.40%	0.1840	1.263835	0.145589	0.1840	18.237317	0.010089	0.126397	99.4460
6	0.007220	18.40%	0.1840	1.324428	0.138928	0.1840	18.237317	0.010089	0.135499	99.2620
7	0.008445	18.40%	0.1840	1.387927	0.132572	0.1840	18.237317	0.010089	0.128839	99.0780
8	0.009812	21.60%	0.2160	1.454470	0.148508	0.2160	18.237317	0.011844	0.122483	98.8940
9	0.011111	21.60%	0.2160	1.524203	0.141713	0.2160	18.237317	0.011844	0.136664	98.6780
10	0.012344	21.60%	0.2160	1.597279	0.135230	0.2160	18.237317	0.011844	0.129870	98.4620
11	0.013662	24.28%	0.2428	1.673859	0.145036	0.2428	18.237317	0.013312	0.123386	98.2460
12	0.014959	24.28%	0.2428	1.754111	0.143487	0.2517	18.237317	0.013801	0.131724	98.0032
13	0.016190	25.17%	0.2517	1.838210	0.136923	0.2517	18.237317	0.013801	0.129686	97.7515
14	0.017452	25.17%	0.2517	1.926341	0.141120	0.2517	18.237317	0.013801	0.123122	97.4998
15	0.018738	27.18%	0.2718	2.018697	0.144648	0.2718	18.237317	0.014906	0.126214	97.2280
16	0.019958	29.20%	0.2920	2.115482	0.138030	0.2920	18.237317	0.016011	0.128637	96.9360
17	0.021160	29.20%	0.2920	2.216906	0.136816	0.2920	18.237317	0.016011	0.122019	96.6440
18	0.022427	30.33%	0.3033	2.323194	0.136816	0.3033	18.237317	0.016631	0.126667	96.3407
19	0.023627	33.72%	0.3372	2.434577	0.145158	0.3372	18.237317	0.018491	0.120185	96.0035
20	0.024764	33.72%	0.3372	2.551300	0.138517	0.3372	18.237317	0.018491	0.126667	95.6662
21	0.026000	33.72%	0.3372	2.673620	0.132180	0.3372	18.237317	0.018491	0.120026	95.3290
22	0.027169	38.71%	0.3871	2.801804	0.144776	0.3871	18.237317	0.021224	0.113689	95.0000
23	0.028275	38.71%	0.3871	2.936134	0.138153	0.3871	18.237317	0.021224	0.123552	94.9419
24	0.029434	38.71%	0.3871	3.076904	0.131832	0.3871	18.237317	0.021224	0.116928	94.5548
25	0.030565	42.91%	0.4291	3.224423	0.131832	0.4291	18.237317	0.023527	0.110608	94.1678
26	0.031634	44.31%	0.4431	3.379015	0.137413	0.4431	18.237317	0.025277	0.106083	93.7387
27	0.032712	44.31%	0.4431	3.541018	0.137413	0.4431	18.237317	0.025277	0.115923	93.2956
28	0.033796	47.40%	0.4740	3.710789	0.131126	0.4740	18.237317	0.027686	0.113118	92.8525
29	0.034818	50.49%	0.5049	3.888699	0.144776	0.5049	18.237317	0.029991	0.106831	92.3785
30	0.035813	50.49%	0.5049	4.075139	0.129844	0.5049	18.237317	0.027686	0.107869	91.8736
31	0.036840	52.20%	0.5220	4.270517	0.128094	0.5220	18.237317	0.027686	0.108383	91.3687
32	0.037807	52.20%	0.5220	4.475263	0.128094	0.5220	18.237317	0.028623	0.102157	90.8467
33	0.038715	57.32%	0.5732	4.689825	0.134230	0.5732	18.237317	0.031432	0.099471	90.2735
34	0.039679	57.32%	0.5732	4.914674	0.128089	0.5732	18.237317	0.031432	0.102798	89.7002
35	0.040582	64.83%	0.6483	5.150303	0.122229	0.6483	18.237317	0.031432	0.090797	89.1270
36	0.041428	64.83%	0.6483	5.397229	0.131913	0.6483	18.237317	0.035548	0.096364	88.4787
37	0.042293	64.83%	0.6483	5.655994	0.125878	0.6483	18.237317	0.035548	0.093548	87.8304
38	0.043125	70.97%	0.7097	5.927165	0.120119	0.7097	18.237317	0.035548	0.090329	87.1821
39	0.043900	70.97%	0.7097	6.211337	0.125476	0.7097	18.237317	0.038914	0.084570	86.4724
40	0.044665	73.02%	0.7302	6.509134	0.125476	0.7302	18.237317	0.040036	0.086562	85.7422
41	0.045417	73.02%	0.7302	6.81208	0.123188	0.7302	18.237317	0.040036	0.083151	85.0121
42	0.046114	77.46%	0.7746	7.148244	0.117552	0.7746	18.237317	0.040036	0.077516	84.2375
43	0.046777	77.46%	0.7746	7.50106	0.119004	0.7746	18.237317	0.042474	0.075166	83.4184
44	0.047441	81.91%	0.8191	7.850106	0.120078	0.8191	18.237317	0.044912	0.069672	82.5993
45	0.048051	81.91%	0.8191	8.226471	0.114584	0.8191	18.237317	0.044912	0.066318	81.7562
46	0.048611	84.31%	0.8431	8.620881	0.112546	0.8431	18.237317	0.046228	0.066393	80.8412
47	0.049179	91.51%	0.9151	9.034201	0.116569	0.9151	18.237317	0.050176	0.061060	79.9261
48	0.049695	91.51%	0.9151	9.467337	0.111236	0.9151	18.237317	0.050176	0.055970	79.0110
49	0.050163	91.51%	0.9151	9.921239	0.106147	0.9151	18.237317	0.055744	0.056786	78.1000
50	0.050616	101.66%	1.0166	10.396903	0.10166	1.0166	18.237317	0.055744	0.051638	77.1944
51	0.051031	101.66%	1.0166	10.895372	0.102469	1.0166	18.237317	0.055744	0.046725	76.2978
52	0.051399	109.65%	1.0965	11.417740	0.105460	1.0965	18.237317	0.060122	0.043339	75.4112
53	0.051737	112.31%	1.1231	11.965152	0.103078	1.1231	18.237317	0.061581	0.041497	74.5416
54	0.052044	112.31%	1.1231	12.538810	0.098362	1.1231	18.237317	0.061581	0.036781	73.6818
55	0.052306	117.74%	1.1774	13.139970	0.098401	1.1774	18.237317	0.064559	0.033842	72.8342
56	0.052530	123.17%	1.2317	13.769953	0.092320	1.2317	18.237317	0.067537	0.030693	71.9944
57	0.052724	123.17%	1.2317	14.430140	0.093736	1.2317	18.237317	0.067537	0.026199	71.1612
58	0.052875	125.87%	1.2587	15.121979	0.091409	1.2587	18.237317	0.073459	0.022391	70.3339
59	0.052986	133.97%	1.3397	15.846987	0.088592	1.3397	18.237317	0.073459	0.019381	69.5112
60	0.053064	133.97%	1.3397	16.606755	0.084539	1.3397	18.237317	0.073459	0.015134	68.6978
		144.25%	1.4425		0.086860	1.4425	18.237317	0.079094	0.011080	67.8944
									0.007766	67.1000
										66.3134
										65.5397
										64.7719
										64.0180
										63.2755

PacifiCorp  
 Oregon Marginal Cost Study  
 Present Value of Cost of Dispersion Factor  
 Iowa Curve R 2 & 65 Year Average Life  
 Page 2 of 2

YEAR	(A) PVCd	(B) % RENEWED	(C) NUM1	(D) DEM1	(E) NUM1/DEM1	(F) NUM2	(G) DEM2	(H) NUM2/DEM2	(I) INSTANCE	(J) Iowa R 2.0
	$\frac{(A) \{yr-1\}}{+(1)} / 100$	$\frac{(J, \{yr-1\}) - (J)}{* 100}$	(B)	1.0479 ^Year	(C) / (D)	(B)	1.0479 ^62	(F) / (G)	(E) - (H)	(Given)
61	0.053101	144.25%	1.4425	17.402950	0.082886	1.4425	18.237317	0.079094	0.003792	60.8151
62	0.053101	144.25%	1.4425	18.237317	0.079094	1.4425	18.237317	0.079094	0.000000	59.3726
63	0.053064	151.15%	1.5115	19.111687	0.079086	1.5115	18.237317	0.082877	-0.003792	57.8612
64	0.052988	153.45%	1.5345	20.027978	0.076616	1.5345	18.237317	0.084139	-0.007523	56.3267
65	0.052878	153.45%	1.5345	20.988199	0.073111	1.5345	18.237317	0.084139	-0.011028	54.7922
66	0.052731	157.20%	1.5720	21.994458	0.071473	1.5720	18.237317	0.086197	-0.014724	53.2202
67	0.052547	160.95%	1.6095	23.048960	0.069831	1.6095	18.237317	0.088255	-0.018424	51.6107
68	0.052330	160.95%	1.6095	24.154020	0.066636	1.6095	18.237317	0.088255	-0.021619	50.0012
69	0.052082	162.24%	1.6224	25.312061	0.064095	1.6224	18.237317	0.088960	-0.024864	48.3788
70	0.051797	166.09%	1.6609	26.525622	0.062616	1.6609	18.237317	0.091073	-0.028457	46.7178
71	0.051484	166.09%	1.6609	27.797367	0.059751	1.6609	18.237317	0.091073	-0.031322	45.0569
72	0.051143	166.09%	1.6609	29.130084	0.057017	1.6609	18.237317	0.091073	-0.034055	43.3960
73	0.050772	168.18%	1.6818	30.526697	0.055094	1.6818	18.237317	0.092220	-0.037126	41.7142
74	0.050376	168.18%	1.6818	31.990270	0.052574	1.6818	18.237317	0.092220	-0.039646	40.0323
75	0.049955	168.18%	1.6818	33.524011	0.050168	1.6818	18.237317	0.092220	-0.042052	38.3505
76	0.049515	167.10%	1.6710	35.131287	0.047564	1.6710	18.237317	0.091625	-0.044061	36.6795
77	0.049053	166.74%	1.6674	36.815622	0.045290	1.6674	18.237317	0.091427	-0.046137	35.0121
78	0.048571	166.74%	1.6674	38.580710	0.043218	1.6674	18.237317	0.091427	-0.048209	33.3447
79	0.048077	164.06%	1.6406	40.430424	0.040579	1.6406	18.237317	0.089959	-0.049381	31.7041
80	0.047573	161.38%	1.6138	42.368821	0.038090	1.6138	18.237317	0.088491	-0.050401	30.0902
81	0.047052	161.38%	1.6138	44.400152	0.036348	1.6138	18.237317	0.088491	-0.052144	28.4764
82	0.046521	159.09%	1.5909	46.528873	0.034192	1.5909	18.237317	0.087234	-0.053042	26.8855
83	0.045999	152.22%	1.5222	48.759654	0.031217	1.5222	18.237317	0.083464	-0.052246	25.3633
84	0.045462	152.22%	1.5222	51.097388	0.029789	1.5222	18.237317	0.083464	-0.053674	23.8412
85	0.044912	152.22%	1.5222	53.547201	0.028426	1.5222	18.237317	0.083464	-0.055037	22.3190
86	0.044395	139.60%	1.3960	56.114469	0.024878	1.3960	18.237317	0.076546	-0.051669	20.9230
87	0.043867	139.60%	1.3960	58.804822	0.023740	1.3960	18.237317	0.076546	-0.052807	19.5270
88	0.043328	139.60%	1.3960	61.624160	0.022653	1.3960	18.237317	0.076546	-0.053893	18.1310
89	0.042824	128.13%	1.2813	64.578670	0.019841	1.2813	18.237317	0.070257	-0.050416	16.8497
90	0.042326	124.31%	1.2431	67.674830	0.018368	1.2431	18.237317	0.068161	-0.049793	15.6066
91	0.041820	124.31%	1.2431	70.919433	0.017528	1.2431	18.237317	0.068161	-0.050633	14.3635
92	0.041340	115.85%	1.1585	74.319595	0.015588	1.1585	18.237317	0.063521	-0.047934	13.2051
93	0.040889	107.38%	1.0738	77.882775	0.013788	1.0738	18.237317	0.058882	-0.045094	12.1312
94	0.040432	107.38%	1.0738	81.616787	0.013157	1.0738	18.237317	0.058882	-0.045725	11.0574
95	0.039988	103.02%	1.0302	85.529823	0.012045	1.0302	18.237317	0.056490	-0.044445	10.0272
96	0.039595	89.94%	0.8994	89.630466	0.010034	0.8994	18.237317	0.049316	-0.039281	9.1278
97	0.039198	89.94%	0.8994	93.927710	0.009575	0.8994	18.237317	0.049316	-0.039740	8.2284
98	0.038796	89.94%	0.8994	98.430981	0.009137	0.8994	18.237317	0.049316	-0.040178	7.3290
99	0.038467	72.86%	0.7286	103.150157	0.007064	0.7286	18.237317	0.039952	-0.032888	6.6004
100	0.038135	72.86%	0.7286	108.095589	0.006740	0.7286	18.237317	0.039952	-0.033211	5.8718
101	0.037800	72.86%	0.7286	113.278125	0.006432	0.7286	18.237317	0.039952	-0.033520	5.1432
102	0.037517	60.84%	0.6084	118.709133	0.005125	0.6084	18.237317	0.033359	-0.028234	4.5348
103	0.037251	56.83%	0.5683	124.400525	0.004568	0.5683	18.237317	0.031162	-0.026593	3.9665
104	0.036983	56.83%	0.5683	130.364785	0.004359	0.5683	18.237317	0.031162	-0.026802	3.3982
105	0.036748	49.42%	0.4942	136.614995	0.003617	0.4942	18.237317	0.027096	-0.023479	2.9040
106	0.036548	42.00%	0.4200	143.164866	0.002934	0.4200	18.237317	0.023030	-0.020096	2.4840
107	0.036345	42.00%	0.4200	150.028764	0.002799	0.4200	18.237317	0.023030	-0.020230	2.0640
108	0.036158	38.63%	0.3863	157.221744	0.002457	0.3863	18.237317	0.021182	-0.018725	1.6777
109	0.036019	28.52%	0.2852	164.759585	0.001731	0.2852	18.237317	0.015640	-0.013909	1.3925
110	0.035879	28.52%	0.2852	172.658821	0.001652	0.2852	18.237317	0.015640	-0.013988	1.1072
111	0.035738	28.52%	0.2852	180.936777	0.001576	0.2852	18.237317	0.015640	-0.014064	0.8220
112	0.035656	16.68%	0.1668	189.611612	0.000880	0.1668	18.237317	0.009144	-0.008265	0.6552
113	0.035573	16.68%	0.1668	198.702353	0.000839	0.1668	18.237317	0.009144	-0.008305	0.4885
114	0.035489	16.68%	0.1668	208.228940	0.000801	0.1668	18.237317	0.009144	-0.008344	0.3217
115	0.035441	9.57%	0.0957	218.212271	0.000439	0.0957	18.237317	0.005247	-0.004809	0.2260
116	0.035405	7.20%	0.0720	228.674242	0.000315	0.0720	18.237317	0.003948	-0.003633	0.1540
		99.8460	99.8460							

PacifiCorp  
 Oregon Marginal Cost Study  
 Present Value of Cost of Dispersion Factor  
 Iowa Curve R 2 & 53 Year Average Life

Real Cost of Capital = 4.79%

YEAR	(A) PVCD	(B) % RENEWED	(C) NUM1	(D) DEM1	(E) NUM1/DEM1	(F) NUM2	(G) DEM2	(H) NUM2/DEM2	(I) INSTANCE	(J) Iowa R 2.0
	$\frac{(A)\{yr-1\}}{+(I) / 100}$	$\frac{(J, \{yr-1\}) - (J)}{* 100}$	(B)	$1.0479^{Year}$	(C) / (D)	(B)	$1.0479^{52}$	(F) / (G)	(E) - (H)	(Given)
1	0.000831	9.58%	0.0958	1.047944	0.091464	0.0958	11.417740	0.008395	0.083069	100.0000
2	0.002408	19.17%	0.1917	1.098187	0.174559	0.1917	11.417740	0.016789	0.157769	99.9042
3	0.003906	19.17%	0.1917	1.150838	0.166573	0.1917	11.417740	0.016789	0.149783	99.7125
4	0.005542	22.06%	0.2206	1.206014	0.182888	0.2206	11.417740	0.019318	0.163571	99.5208
5	0.007130	22.57%	0.2257	1.263835	0.178552	0.2257	11.417740	0.019764	0.158788	99.3002
6	0.008688	23.35%	0.2335	1.324428	0.176310	0.2335	11.417740	0.020451	0.155858	99.0745
7	0.010365	26.49%	0.2649	1.387927	0.190864	0.2649	11.417740	0.023201	0.167663	98.8410
8	0.011954	26.49%	0.2649	1.454470	0.182132	0.2649	11.417740	0.023201	0.158931	98.5761
9	0.013597	28.90%	0.2890	1.524203	0.189595	0.2890	11.417740	0.025310	0.164285	98.3112
10	0.015259	30.87%	0.3087	1.597279	0.193253	0.3087	11.417740	0.027035	0.166218	98.0222
11	0.016833	30.87%	0.3087	1.673859	0.184412	0.3087	11.417740	0.027035	0.162783	97.7135
12	0.018537	35.32%	0.3532	1.754111	0.201338	0.3532	11.417740	0.030932	0.157377	97.4049
13	0.020172	35.81%	0.3581	1.838210	0.194816	0.3581	11.417740	0.031365	0.170407	97.0517
14	0.021777	37.20%	0.3720	1.926341	0.193102	0.3720	11.417740	0.032579	0.163452	96.6936
15	0.023463	41.36%	0.4136	2.018697	0.204877	0.4136	11.417740	0.036223	0.160523	96.3216
16	0.025056	41.36%	0.4136	2.115482	0.195504	0.4136	11.417740	0.036223	0.166654	95.9080
17	0.026693	45.03%	0.4503	2.216906	0.203105	0.4503	11.417740	0.039435	0.159281	95.4944
18	0.028321	47.47%	0.4747	2.323194	0.204338	0.4747	11.417740	0.041577	0.163669	95.0442
19	0.029855	47.47%	0.4747	2.434577	0.194990	0.4747	11.417740	0.041577	0.162714	94.5695
20	0.031498	54.00%	0.5400	2.551300	0.211642	0.5400	11.417740	0.047292	0.153412	94.0947
21	0.033055	54.34%	0.5434	2.673620	0.203244	0.5434	11.417740	0.047292	0.164350	93.5548
22	0.034580	56.62%	0.5662	2.801804	0.202067	0.5662	11.417740	0.049585	0.155651	93.0114
23	0.036146	61.92%	0.6192	2.936134	0.210905	0.6192	11.417740	0.054235	0.152481	92.4452
24	0.037616	61.92%	0.6192	3.076904	0.201256	0.6192	11.417740	0.054235	0.156670	91.8260
25	0.039116	67.37%	0.6737	3.224423	0.208936	0.6737	11.417740	0.059005	0.147021	91.2067
26	0.040581	70.30%	0.7030	3.379015	0.208054	0.7030	11.417740	0.061573	0.149932	90.5330
27	0.041950	70.30%	0.7030	3.541018	0.198536	0.7030	11.417740	0.061573	0.146482	89.8300
28	0.043397	79.51%	0.7951	3.710789	0.214266	0.7951	11.417740	0.069637	0.136963	89.1270
29	0.044745	79.51%	0.7951	3.888699	0.204463	0.7951	11.417740	0.069637	0.144629	88.3319
30	0.046055	83.02%	0.8302	4.075139	0.203730	0.8302	11.417740	0.072714	0.134826	87.5368
31	0.047368	89.55%	0.8955	4.270517	0.209687	0.8955	11.417740	0.078428	0.131016	86.7066
32	0.048584	89.55%	0.8955	4.475263	0.200094	0.8955	11.417740	0.078428	0.121259	85.8111
33	0.049805	97.18%	0.9718	4.689825	0.207217	0.9718	11.417740	0.085114	0.117021	84.9156
34	0.050969	100.45%	1.0045	4.914674	0.204394	1.0045	11.417740	0.087980	0.122103	83.9438
35	0.052046	101.04%	1.0104	5.150303	0.196186	1.0104	11.417740	0.088495	0.116414	82.9393
36	0.053143	112.23%	1.1223	5.397229	0.207933	1.1223	11.417740	0.098291	0.107690	81.9289
37	0.054144	112.23%	1.1223	5.655994	0.198420	1.1223	11.417740	0.098291	0.109642	80.8066
38	0.055095	117.21%	1.1721	5.927165	0.197746	1.1721	11.417740	0.102654	0.100129	79.6844
39	0.056010	124.68%	1.2468	6.211337	0.200729	1.2468	11.417740	0.109198	0.095092	78.5123
40	0.056834	124.68%	1.2468	6.509134	0.191545	1.2468	11.417740	0.109198	0.091531	77.2655
41	0.057627	134.47%	1.3447	6.821208	0.197138	1.3447	11.417740	0.117774	0.082347	76.0187
42	0.058348	137.74%	1.3774	7.148244	0.192685	1.3774	11.417740	0.120633	0.079363	74.6740
43	0.058986	139.07%	1.3907	7.490959	0.185648	1.3907	11.417740	0.121800	0.072052	73.2966
44	0.059588	151.06%	1.5106	7.850106	0.192426	1.5106	11.417740	0.132300	0.063848	71.9059
									0.060126	70.3954

PacifiCorp  
 Oregon Marginal Cost Study  
 Present Value of Cost of Dispersion Factor  
 Iowa Curve R 2 & 53 Year Average Life

Real Cost of Capital = 4.79%

YEAR	(A) PVCD	(B) % RENEWED	(C) NUM1	(D) DEM1	(E) NUM1/DEM1	(F) NUM2	(G) DEM2	(H) NUM2/DEM2	(I) INSTANCE	(J) Iowa R 2.0
	$\frac{(A)_{\{yr-1\}} + (I) / 100}{(A)}$	$\frac{(J)_{\{yr-1\}} - (J)}{100}$	(B)	$1.0479^{Year}$	(C) / (D)	(B)	$1.0479^{52}$	(F) / (G)	(E) - (H)	(Given)
45	0.060101	151.06%	1.5106	8.226471	0.183623	1.5106	11.417740	0.132300	0.051323	68.8848
46	0.060547	157.02%	1.5702	8.620881	0.182136	1.5702	11.417740	0.137520	0.044615	67.3146
47	0.060927	164.30%	1.6430	9.034201	0.181867	1.6430	11.417740	0.143901	0.037966	65.6716
48	0.061223	164.30%	1.6430	9.467337	0.173546	1.6430	11.417740	0.143901	0.029646	64.0286
49	0.061453	174.38%	1.7438	9.921239	0.175769	1.7438	11.417740	0.152732	0.023038	62.2848
50	0.061606	176.91%	1.7691	10.396903	0.170152	1.7691	11.417740	0.154939	0.015213	60.5157
51	0.061681	178.60%	1.7860	10.895372	0.163921	1.7860	11.417740	0.156422	0.007499	58.7297
52	0.061681	188.19%	1.8819	11.417740	0.164821	1.8819	11.417740	0.164821	0.000000	56.8478
53	0.061605	188.19%	1.8819	11.965152	0.157281	1.8819	11.417740	0.164821	-0.007541	54.9659
54	0.061454	192.79%	1.9279	12.538810	0.153757	1.9279	11.417740	0.168853	-0.015097	53.0380
55	0.061228	197.40%	1.9740	13.139970	0.150226	1.9740	11.417740	0.172886	-0.022660	51.0641
56	0.060932	197.40%	1.9740	13.769953	0.143353	1.9740	11.417740	0.172886	-0.029533	49.0901
57	0.060562	202.75%	2.0275	14.430140	0.140506	2.0275	11.417740	0.177577	-0.037071	47.0626
58	0.060125	203.70%	2.0370	15.121979	0.134703	2.0370	11.417740	0.178405	-0.043702	45.0256
59	0.059625	204.21%	2.0421	15.846987	0.128864	2.0421	11.417740	0.178854	-0.049990	42.9835
60	0.059060	206.26%	2.0626	16.606755	0.124205	2.0626	11.417740	0.180652	-0.056447	40.9208
61	0.058439	206.26%	2.0626	17.402950	0.118523	2.0626	11.417740	0.180652	-0.062130	38.8582
62	0.057767	205.29%	2.0529	18.237317	0.112565	2.0529	11.417740	0.179798	-0.067233	36.8053
63	0.057046	204.49%	2.0449	19.111687	0.106998	2.0449	11.417740	0.179099	-0.072101	34.7604
64	0.056276	204.49%	2.0449	20.027978	0.102102	2.0449	11.417740	0.179099	-0.076997	32.7155
65	0.055482	198.58%	1.9858	20.988199	0.094616	1.9858	11.417740	0.173923	-0.079308	30.7297
66	0.054649	197.92%	1.9792	21.994458	0.089988	1.9792	11.417740	0.173348	-0.083360	28.7504
67	0.053787	195.11%	1.9511	23.048960	0.084652	1.9511	11.417740	0.170886	-0.086234	26.7993
68	0.052924	186.68%	1.8668	24.154020	0.077287	1.8668	11.417740	0.163499	-0.086212	24.9325
69	0.052027	186.68%	1.8668	25.312061	0.073751	1.8668	11.417740	0.163499	-0.089748	23.0657
70	0.051142	177.40%	1.7740	26.525622	0.066877	1.7740	11.417740	0.155369	-0.088492	21.2918
71	0.050258	171.21%	1.7121	27.797367	0.061591	1.7121	11.417740	0.149949	-0.088357	19.5797
72	0.049347	171.21%	1.7121	29.130084	0.058773	1.7121	11.417740	0.149949	-0.091175	17.8676
73	0.048506	153.39%	1.5339	30.526697	0.050248	1.5339	11.417740	0.134344	-0.084096	16.3337
74	0.047647	152.45%	1.5245	31.990270	0.047656	1.5245	11.417740	0.133523	-0.085867	14.8092
75	0.046803	146.23%	1.4623	33.524011	0.043618	1.4623	11.417740	0.128069	-0.084451	13.3469
76	0.046024	131.70%	1.3170	35.131287	0.037487	1.3170	11.417740	0.115345	-0.077858	12.0299
77	0.045228	131.70%	1.3170	36.815622	0.035772	1.3170	11.417740	0.115345	-0.079573	10.7129
78	0.044502	117.79%	1.1779	38.580710	0.030531	1.1779	11.417740	0.103165	-0.072634	9.5350
79	0.043809	110.30%	1.1030	40.430424	0.027282	1.1030	11.417740	0.096606	-0.069324	8.4320
80	0.043103	110.30%	1.1030	42.368821	0.026034	1.1030	11.417740	0.096606	-0.070572	7.3290
81	0.042522	89.36%	0.8936	44.400152	0.020126	0.8936	11.417740	0.078263	-0.058137	6.4354
82	0.041931	89.36%	0.8936	46.528873	0.019205	0.8936	11.417740	0.078263	-0.059058	5.5418
83	0.041378	82.48%	0.8248	48.759654	0.016915	0.8248	11.417740	0.072236	-0.055321	4.7171
84	0.040904	69.70%	0.6970	51.097388	0.013640	0.6970	11.417740	0.061044	-0.047403	4.0201
85	0.040423	69.70%	0.6970	53.547201	0.013016	0.6970	11.417740	0.061044	-0.048028	3.3231
86	0.040026	56.97%	0.5697	56.114469	0.010152	0.5697	11.417740	0.049893	-0.039741	2.7534
87	0.039663	51.51%	0.5151	58.804822	0.008759	0.5151	11.417740	0.045114	-0.036354	2.2383
88	0.039301	50.68%	0.5068	61.624160	0.008225	0.5068	11.417740	0.044390	-0.036165	1.7315
89	0.039049	34.98%	0.3498	64.578670	0.005417	0.3498	11.417740	0.030638	-0.025221	1.3817
90	0.038794	34.98%	0.3498	67.674830	0.005169	0.3498	11.417740	0.030638	-0.025469	1.0319
91	0.038580	29.17%	0.2917	70.919433	0.004113	0.2917	11.417740	0.025548	-0.021435	0.7402
92	0.038428	20.45%	0.2045	74.319595	0.002752	0.2045	11.417740	0.017913	-0.015161	0.5357
93	0.038275	20.45%	0.2045	77.882775	0.002626	0.2045	11.417740	0.017913	-0.015287	0.3311
94	0.038187	11.74%	0.1174	81.616787	0.001438	0.1174	11.417740	0.010279	-0.008841	0.2138
95	0.038120	8.83%	0.0883	85.529823	0.001032	0.0883	11.417740	0.007734	-0.006701	0.1255
96	0.038058	8.12%	0.0812	89.630466	0.000906	0.0812	11.417740	0.007112	-0.006206	0.0443
97	0.038044	1.74%	0.0174	93.927710	0.000185	0.0174	11.417740	0.001520	-0.001336	0.0269
			99.9731	53.9743						



Charge 6

PACIFICORP  
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 6/30/2021 Balance \$	[4] IOWA CURVE	[5] Average Life Yrs	[6] NET SALVAGE		[7] Amount \$
					Percent %	Amount \$	
<b>TRANSMISSION PLANT</b>							
350.20	Land Rights	246,448,855	R4	90.00	0.00%	-	
352.00	Structures & Improvements	313,031,140	R2.5	75.00	-5.00%	(15,651,557)	
353.00	Station Equipment	2,341,673,890	S0	60.00	-10.00%	(234,167,389)	
353.70	Supervisory Equipment	-				-	
354.00	Towers & Fixtures	1,333,441,145	R4	72.00	-8.00%	(106,675,292)	
355.00	Poles & Fixtures	1,109,258,265	R2.5	62.00	-40.00%	(443,703,306)	
356.00	OH Conductors & Devices	1,379,078,572	R2.5	68.00	-30.00%	(413,723,571)	
356.20	Clearing	-				-	
357.00	UG Conduit	3,857,965	S2.5	60.00	0.00%	-	
358.00	UG Conductors & Devices	9,080,617	S2.5	60.00	-5.00%	(454,031)	
359.00	Roads & Trails	12,146,013	R5	75.00	0.00%	-	
	Total Transmission Plant	6,748,016,462		65.30	-18.00%	(1,214,375,146)	
				<b>Use 65 Years</b>			

65

TRANSMISSION PLANT excludes land accounts

352.00	Structures & Improvements	313,031,140	2.50	4.81%	0.1204	
353.00	Station Equipment	2,341,673,890	-	36.02%	-	
353.70	Supervisory Equipment	-		0.00%	-	
354.00	Towers & Fixtures	1,333,441,145	4.00	20.51%	0.8204	
355.00	Poles & Fixtures	1,109,258,265	2.50	17.06%	0.4265	
356.00	OH Conductors & Devices	1,379,078,572	2.50	21.21%	0.5303	
356.20	Clearing	-	-	0.00%	-	
357.00	UG Conduit	3,857,965	2.50	0.06%	0.0015	
358.00	UG Conductors & Devices	9,080,617	2.50	0.14%	0.0035	
359.00	Roads & Trails	12,146,013	5.00	0.19%	0.0093	
	Total Transmission Plant	6,501,567,606		100.00%	1.9119	<b>Use R 2</b>

PACIFICORP  
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 6/30/2021 Balance \$	[4] IOWA CURVE	[5] Average Life Yrs	[6] NET SALVAGE		[7] Amount \$
					Percent %	Amount \$	
<b>DISTRIBUTION PLANT (OREGON)</b>							
360.20	Land Rights	5,274,460	S1.5	70.00	0.00%	-	
361.00	Structures & Improvements	32,761,372	R2	67.00	-10.00%	(3,276,137)	
362.00	Station Equipment	262,150,735	R1	53.00	-20.00%	(52,430,147)	
362.70	Supervisory & Alarm Equipment	-				-	
364.00	Poles, Towers & Fixtures	452,281,633	R1	58.00	-100.00%	(452,281,633)	
365.00	OH Conductors & Devices	299,985,292	R1	65.00	-50.00%	(149,992,646)	
366.00	UG Conduit	106,676,187	R3	75.00	-45.00%	(48,004,284)	
367.00	UG Conductors & Devices	208,212,087	R2.5	60.00	-35.00%	(72,874,231)	
368.00	Line Transformers	498,477,508	R1.5	46.00	-25.00%	(124,619,377)	
369.10	Overhead Services	106,497,157	R2	60.00	-35.00%	(37,274,005)	
369.20	Underground Services	219,245,299	R4	60.00	-40.00%	(87,698,120)	
370.00	Meters	97,716,304	S3	20.00	-3.00%	(2,931,489)	
371.00	I.O.C.P.	2,666,274	L0	27.00	-50.00%	(1,333,137)	
373.00	Street Lighting & Signal Systems	24,884,170	R1	45.00	30.00%	7,465,251	
	Total OREGON Distribution Plant	2,316,828,478		53.48	-44.25%	(1,025,249,955)	
				<b>Use 53 years</b>			

53

DISTRIBUTION PLANT excludes land accounts (OREGON)

361.00	Structures & Improvements	32,761,372	2.00	1.42%	0.03	Curves:
362.00	Station Equipment	262,150,735	1.00	11.34%	0.11	R=positive
362.70	Supervisory & Alarm Equipment	-		0.00%	0.00	L=negative
364.00	Poles, Towers & Fixtures	452,281,633	1.00	19.57%	0.20	S=0
365.00	OH Conductors & Devices	299,985,292	1.00	12.98%	0.13	
366.00	UG Conduit	106,676,187	3.00	4.61%	0.14	R means right of the standard
367.00	UG Conductors & Devices	208,212,087	2.50	9.01%	0.23	L means left of the standard
368.00	Line Transformers	498,477,508	1.50	21.56%	0.32	S is at the standard
369.10	Overhead Services	106,497,157	2.00	4.61%	0.09	
369.20	Underground Services	219,245,299	4.00	9.48%	0.38	
370.00	Meters	97,716,304	3.00	4.23%	0.13	
371.00	I.O.C.P.	2,666,274	-	0.12%	0.00	
373.00	Street Lighting & Signal Systems	24,884,170	1.00	1.08%	0.01	
	Total OREGON Distribution Plant	2,311,554,018		100.00%	1.76	<b>Use R 2</b>

Losses

PacifiCorp  
Oregon Marginal Cost Study  
Energy Loss Factors

	(A)	(B)	(C)	(D)	(E)
		Energy	Energy	Demand	Demand
Line	Voltage Level	Factor	Loss	Factor	Loss
			Percent		Percent
1	Transmission	1.03503	3.50%	1.03816	3.82%
2	Primary	1.06294	6.29%	1.07038	7.04%
3	Secondary	1.07965	7.97%	1.08467	8.47%

Cust Data 1

PacifiCorp  
 Oregon Marginal Cost Study  
 Customers and MWh @ Sales  
 12 Months Ended June 30, 2021 - Actual

Line	Description	(A) Del. Volt	(B) Average Customers	(C) % Total Class	(D) Annual MWh's	(E) % Total Class	(F) Average Billing kW	(G) % Total Class
1	Res - Schedule 4	(sec)	519,723	100.0%	5,755,783	100.0%	5,094,228	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	70,227	82.9%	567,191	48.1%	598,673	61.7%
5	15+ kW	(sec)	14,495	17.1%	612,100	51.9%	371,428	38.3%
6	Sec Subtotal		84,722	100.0%	1,179,291	100.0%	970,100	100.0%
7	Primary	(pri)	116		3,443		5,687	
8	Total		84,838		1,182,733		975,787	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,736	46.4%	442,735	22.2%	269,617	25.4%
12	51-100 kW	(sec)	3,501	34.3%	673,777	33.8%	444,697	41.8%
13	100 + kW	(sec)	1,977	19.4%	876,851	44.0%	349,255	32.8%
14	Sec Subtotal		10,214	100.0%	1,993,363	100.0%	1,063,568	100.0%
15	Primary	(pri)	68		24,061		12,225	
16	Total		10,282		2,017,424		1,075,794	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	217	28.7%	186,365	16.2%	63,411	21.0%
20	300+ kW	(sec)	539	71.3%	966,612	83.8%	239,143	79.0%
21	Sec Subtotal		756	100.0%	1,152,977	100.0%	302,554	100.0%
22	Primary	(pri)	53		95,500		24,614	
23	Total		810		1,248,477		327,167	
24								
25	LPS - Schedule 48							
26	1 - 4 MW	(sec)	93	98.9%	503,599	92.9%	119,399	93.6%
27	> 4 MW	(sec)	1	1.1%	38,440	7.1%	8,225	6.4%
28	Sec Subtotal		94	100.0%	542,039	100.0%	127,624	100.0%
29	1 - 4 MW	(pri)	61	68.5%	510,192	34.2%	146,695	39.0%
30	> 4 MW	(pri)	28	31.5%	983,483	65.8%	229,520	61.0%
31	Pri Subtotal		89	100.0%	1,493,675	100.0%	376,215	100.0%
32	Trans	(trn)	8		837,259		309,205	
33	Total		191		2,872,973		813,044	
34								
35	Irrigation - Schedule 41 (Average)	(sec)	3,580	100.0%	237,458	100.0%	211,511	100.0%
36								
37	Irrigation - Schedule 41 (Annual)	(sec)	6,572					

PacifiCorp  
Oregon Marginal Cost Study  
Customers and MWh @ Sales  
12 Months Ended December 2023 - Normalized

Line	Description	(A) Del. Volt	(B) Average Customers	(C) % Total Class	(D) Annual MWh's	(E) % Total Class	(F) Average Billing kW	(G) % Total Class
1	Res - Schedule 4	(sec)	535,059	100.0%	5,633,856	100.0%	5,094,228	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	69,806	82.9%	545,258	48.1%	598,673	61.7%
5	15+ kW	(sec)	14,408	17.1%	588,429	51.9%	371,428	38.3%
6	Sec Subtotal		84,214	100.0%	1,133,687	100.0%	970,100	100.0%
7	Primary	(pri)	115		3,324		5,687	
8	Total		84,329		1,137,011		975,787	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,819	46.4%	437,206	22.2%	269,617	25.4%
12	51-100 kW	(sec)	3,562	34.3%	665,361	33.8%	444,697	41.8%
13	100 + kW	(sec)	2,012	19.4%	865,899	44.0%	349,255	32.8%
14	Sec Subtotal		10,393	100.0%	1,968,466	100.0%	1,063,568	100.0%
15	Primary	(pri)	69		23,804		12,225	
16	Total		10,462		1,992,271		1,075,794	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	213	28.7%	191,241	16.2%	63,411	21.0%
20	300+ kW	(sec)	531	71.3%	991,901	83.8%	239,143	79.0%
21	Sec Subtotal		744	100.0%	1,183,142	100.0%	302,554	100.0%
22	Primary	(pri)	53		98,439		24,614	
23	Total		797		1,281,581		327,167	
24								
25	LPS - Schedule 48							
26	1 - 4 MW	(sec)	92	98.9%	507,196	92.9%	119,399	93.6%
27	> 4 MW	(sec)	1	1.1%	38,715	7.1%	8,225	6.4%
28	Sec Subtotal		93	100.0%	545,911	100.0%	127,624	100.0%
29	1 - 4 MW	(pri)	61	68.5%	500,164	34.2%	146,695	39.0%
30	> 4 MW	(pri)	28	31.5%	964,153	65.8%	229,520	61.0%
31	Pri Subtotal		89	100.0%	1,464,317	100.0%	376,215	100.0%
32	Trans	(trn)	8		1,545,236		309,205	
33	Total		190		3,555,464		813,044	
34								
35	Irrigation - Schedule 41 (Average)	(sec)	4,356	100.0%	263,565	100.0%	211,511	100.0%
36								
37	Irrigation - Schedule 41 (Annual)	(sec)	7,997	100.0%	263,565	100.0%	211,511	100.0%

Cust Data 3

PacifiCorp  
Oregon Marginal Cost Study  
Customer Class Split between  
Three Phase / Single Phase

Line	Customer Class	(A) Voltage Level	(B) Three Phase	(C) Total Customers	(D) Three Phase % of Customers	(E) Single Phase % of Customers
1	Res - Schedule 4	(sec)	-	519,723	0.0000%	100.0000%
2						
3	GS - Schedule 23					
4	0-15 kW	(sec)	13,464	70,227	19.1716%	80.8284%
5	15+ kW	(sec)	6,617	14,495	45.6506%	54.3494%
6	Sec Subtotal		20,081	84,722		
7	Primary	(pri)	116	116	100.0000%	0.0000%
8	Total		20,196	84,838	23.8060%	76.1940%
9						
10	GS - Schedule 28					
11	0-50 kW	(sec)	3,369	4,736	71.1213%	28.8787%
12	51-100 kW	(sec)	3,056	3,501	87.3107%	12.6893%
13	100 + kW	(sec)	1,946	1,977	98.4362%	1.5638%
14	Sec Subtotal		8,371	10,214		
15	Primary	(pri)	68	68	100.0000%	0.0000%
16	Total		8,439	10,282	82.0761%	17.9239%
17						
18	GS - Schedule 30					
19	0-300 kW		216	217	99.5324%	0.4676%
20	300+ kW		539	539	100.0000%	0.0000%
21	Sec Subtotal		755	756		
22	Primary		53	53	100.0000%	0.0000%
23	Total		809	810	99.8748%	0.1252%
24						
25	LPS - Schedule 48					
26	1 - 4 MW	(sec)	93	93	100.0000%	0.0000%
27	1 - 4 MW	(pri)	61	61	100.0000%	0.0000%
28	> 4 MW	(sec)	1	1	100.0000%	0.0000%
29	> 4 MW	(pri)	28	28	100.0000%	0.0000%
30	Trans	(trn)	8	8	100.0000%	0.0000%
31	Total		191	191	100.0000%	0.0000%
32						
33	Irrigation - Schedule 41 (Annual)	(sec)	5,551	6,569	84.4991%	15.5009%

Cust Data 4

PacifiCorp  
Oregon Marginal Cost Study  
Customer Loads at Sales - MW  
12 Months Ended December 2023

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Line	Description	Del. Volt	System Peak	Weighted Distribution Peak	Non-Coincident Peak	Cust per Transformer	Coincidence Factor for Winter Loads	Weighted Transformer Peak		
1	Res - Schedule 4	(sec)	1,062	1,266	5,094	4	0.67	3,413		
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	85	84	599	3	0.70	419		
5	15+ kW	(sec)	92	93	371	3	0.70	260		
6	Primary	(pri)	0	0	6	1	1.00	6		
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	67	67	270	1	1.00	270		
10	51-100 kW	(sec)	100	98	445	1	1.00	445		
11	100 + kW	(sec)	127	125	349	1	1.00	349		
12	Primary	(pri)	3	3	12	1	1.00	12		
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	28	28	63	1	1.00	63		
16	300+ kW	(sec)	137	137	239	1	1.00	239		
17	Primary	(pri)	14	13	25	1	1.00	25		
18										
19	LPS - Schedule 48									
20	1 - 4 MW	(sec)	69	70	119	1	1.00	119		
21	1 - 4 MW	(pri)	65	66	147	1	1.00	147		
22	> 4 MW	(sec)	5	5	8	1	1.00	8		
23	> 4 MW	(pri)	117	120	230	1	1.00	230		
24	Trans	(trn)	179	179	309	1	1.00	309		
25										
26	Irrigation - Sch 41	(sec)	35	62	212	1	1.00	212		
27										
28	Customer-Owned Lighting - Sch 53		1	0	3	1	1.00	3		
29										
30	Rec Field Lighting - Sch 54		0	0	5	1	1.00	5		

Cust per Transformer	Coincidence Factor	
	Summer loads	Winter Loads
1	1.00	1.00
2	0.90	0.77
3	0.86	0.70
4	0.82	0.67
5	0.78	0.64
6	0.76	0.62
7	0.74	0.60
8	0.72	0.59
9	0.71	0.58
10	0.70	0.57
11 or more	0.70	0.56

Source: Coincidence Factors -  
Distribution Construction Standard, DA 411  
(June 30, 2016)

Cust Data 5

PacificCorp  
Oregon Marginal Cost Study  
Distribution Substations Monthly Peaks - kW  
12 months ended June 2021

Δ	B	C	D	E	E	G	H	I	I	K	L	M	N	Q	P
		Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Peak Month	Peak Load
Substation															
Agness Avenue		18,670	17,669	17,753	18,299	15,726	16,050	16,165	15,579	16,119	14,036	13,946	20,002	Jun-21	20,002
Albina		20,299	20,344	20,351	20,311	18,257	18,636	18,950	18,043	18,950	17,422	17,422	23,099	Nov-20	23,311
Alderwood		22,799	22,936	23,072	19,702	16,939	17,561	17,762	18,121	17,295	18,930	19,315	26,041	Jun-21	26,041
Applegate		10,566	10,177	9,875	10,197	12,230	12,751	11,914	11,678	11,350	9,900	8,234	11,408	Dec-20	12,751
Ashland		16,218	16,289	15,662	11,531	14,455	14,748	15,520	15,243	13,927	11,401	12,178	18,448	Jun-21	18,448
Bandon		1,690	1,736	1,816	1,882	2,111	1,932	2,331	2,603	3,108	3,215	2,154	1,785	Apr-21	3,215
Beall Lane		19,544	19,142	19,283	14,452	15,755	15,432	16,158	15,731	14,691	13,261	14,400	20,457	Jun-21	20,457
Bellmap		29,464	29,661	30,446	21,786	23,281	23,882	30,618	35,197	33,489	27,214	32,081	46,154	Jun-21	46,154
Bend Plant		18,427	16,183	17,311	13,947	14,329	15,595	15,946	16,759	12,161	10,785	11,936	22,254	Jun-21	22,254
Bloss		8,574	8,942	8,997	8,688	9,425	9,298	10,961	11,643	11,843	10,348	11,520	10,166	Mar-21	11,843
Bond Street		15,605	14,136	14,733	13,849	13,031	14,365	14,436	14,676	12,868	11,456	10,896	21,809	Jun-21	21,809
Brookhurst		37,624	38,040	37,156	23,853	24,979	27,150	25,827	28,770	28,093	23,991	30,550	41,875	Jun-21	41,875
Bryant		22,851	22,769	23,241	17,696	19,176	20,406	23,093	21,162	26,013	16,098	18,520	28,149	Jun-21	28,149
Buchanan		22,739	21,259	22,736	22,532	22,997	23,292	25,550	24,844	21,769	20,507	17,384	27,920	Jun-21	27,920
Buckaroo		19,634	24,394	23,051	20,358	20,857	17,287	18,642	18,212	19,458	16,807	15,532	17,009	Aug-20	24,394
Calapooia		5,462	5,464	5,460	5,267	5,441	5,729	5,612	5,539	5,283	4,999	4,504	6,001	Jun-21	6,001
Campbell		24,437	24,026	24,687	19,373	23,055	16,038	16,446	15,361	14,501	12,852	16,618	23,289	Sep-20	24,687
Cannon Beach		4,808	4,415	4,647	6,882	6,916	6,951	7,146	7,010	6,733	6,503	4,860	4,455	Jun-21	7,146
Canyonville		6,635	6,858	6,153	5,721	5,856	6,700	8,117	7,588	7,976	7,858	6,552	8,218	Jun-21	8,218
Casebeer		7,143	6,786	5,325	3,631	2,879	3,106	3,218	2,995	2,943	5,083	7,835	8,647	Jun-21	8,647
Cave Junction		13,026	12,371	13,029	15,198	16,685	17,287	17,939	17,316	18,383	15,749	12,370	14,339	Mar-21	18,383
Caveman		20,537	18,758	19,612	13,331	14,504	15,124	15,173	14,022	14,739	14,490	14,059	21,698	Jun-21	21,698
Cherry Lane		7,532	7,499	7,347	7,549	7,197	7,269	7,422	7,323	7,406	7,543	7,314	7,283	Oct-20	7,549
China Hat		18,707	16,926	17,136	20,047	19,547	20,306	21,448	21,612	19,636	18,433	15,643	22,708	Jun-21	22,708
Circle Blvd		15,877	13,876	13,865	13,374	12,728	12,105	14,351	14,139	14,423	14,919	14,997	17,387	Jun-21	17,387
Cleveland Ave.		23,425	17,773	30,986	29,276	28,639	29,024	30,657	29,078	19,266	28,592	26,808	37,726	Jun-21	37,726
Cloaks		15,140	15,259	14,718	10,302	10,937	11,364	11,494	10,295	10,943	9,311	11,626	17,983	Jun-21	17,983
Colunga		2,347	2,271	2,220	1,800	1,864	2,057	1,978	1,957	1,785	1,646	1,613	2,669	Jun-21	2,669
Columbia		31,691	31,202	28,767	27,507	27,785	29,381	30,187	30,301	28,585	27,152	25,723	33,519	Jun-21	33,519
Coquille		10,097	10,307	10,538	14,615	15,652	16,114	15,832	16,114	15,832	15,738	12,258	13,734	Dec-20	16,282
Cully		16,959	15,031	15,474	11,245	12,374	13,686	16,748	14,955	11,948	8,544	8,849	14,783	Jul-20	16,959
Culver		11,921	11,367	9,672	6,067	10,607	9,406	8,241	9,934	9,048	9,236	9,253	12,834	Jun-21	12,834
Dairy		9,497	8,470	6,598	4,080	1,951	1,918	2,851	2,836	2,868	6,895	8,995	10,111	Jun-21	10,111
Dallas		32,490	32,002	32,124	28,979	32,091	34,343	32,569	34,426	32,147	29,580	26,016	39,591	Jun-21	39,591
Dalreed		31,496	33,608	26,583	15,440	8,098	7,649	7,843	8,113	12,855	18,134	27,254	32,546	Aug-20	33,608
Desshutes		7,992	7,116	7,211	10,933	9,946	11,517	12,026	12,101	10,548	8,916	6,891	9,416	Feb-21	12,101
Devils Lake		20,255	19,421	20,004	28,079	29,640	31,536	32,217	32,116	30,833	28,233	22,730	20,932	Jun-21	32,217
Dixon		3,102	2,854	3,105	2,310	2,223	2,365	2,458	2,509	2,166	2,327	2,468	3,575	Jun-21	3,575
Dodge Bridge		11,321	11,572	11,016	9,981	11,368	11,935	10,431	11,697	15,694	9,258	9,017	12,454	Mar-21	15,694
Dowell		16,037	15,852	15,252	10,513	12,171	12,727	10,431	11,480	11,890	9,258	9,017	12,454	Jul-20	16,037
Easy Valley		19,215	19,912	17,991	14,023	16,682	17,089	16,738	15,759	16,084	13,081	14,942	22,436	Jun-21	22,436
Earp		9,947	8,828	10,418	15,383	17,403	18,606	18,370	18,710	17,895	16,370	12,185	10,479	Feb-21	18,710
Fern Hill		1,782	1,816	2,040	2,751	3,244	3,293	3,362	3,889	2,539	2,400	1,544	1,417	Feb-21	3,889
Fielder Creek		10,843	10,403	10,275	11,325	11,513	11,790	12,164	11,416	12,085	10,819	8,260	12,117	Jun-21	12,164
Foothills Rd		13,819	13,696	13,733	9,388	8,639	9,929	15,808	10,875	9,746	8,989	11,674	15,529	Jun-21	15,808
Gooden Valley		14,641	12,247	14,307	10,856	10,600	10,557	10,310	9,553	10,165	9,181	11,120	16,317	Jun-21	16,317
Glendale		9,728	9,712	9,234	12,282	11,925	12,238	11,734	11,736	11,684	11,373	10,549	11,703	Oct-20	12,282
Gold Hill		8,067	7,996	7,819	6,963	8,035	8,495	7,882	7,629	6,715	6,547	8,668	Jun-21	8,668	
Gordon Hollow		4,216	3,745	3,564	3,696	3,482	3,889	3,848	4,690	3,536	3,259	3,250	4,489	Feb-21	4,690
Goshen		5,394	5,386	5,142	5,746	5,561	6,251	6,309	6,143	5,768	5,463	4,155	6,258	Jun-21	6,309
Grant Street		23,397	24,083	24,233	22,577	25,219	26,452	29,174	28,523	23,985	21,096	21,475	28,826	Jun-21	29,174
Green		14,363	14,209	14,054	12,698	12,871	13,147	13,922	12,465	13,470	11,092	11,092	15,604	Jun-21	15,604
Harrisburg		7,680	6,963	7,025	7,480	7,830	8,426	8,538	8,426	8,423	7,104	5,710	8,485	Jun-21	8,538
Hazlewood		6,882	6,893	6,777	6,509	6,530	6,685	6,747	6,581	6,412	5,583	4,804	7,681	Jun-21	7,681
Hillview		28,190	24,613	29,844	22,584	24,049	24,757	23,912	24,989	24,936	20,954	20,670	31,463	Jun-21	31,463
Holladay		22,036	20,807	20,622	18,123	17,148	17,972	18,619	18,787	16,240	16,627	15,606	21,230	Jul-20	22,036
Hollywood		29,897	28,808	28,763	22,186	24,056	25,548	24,136	29,650	24,040	23,818	22,364	35,974	Jun-21	35,974
Hood River		28,611	27,460	27,206	24,959	24,212	31,175	26,571	30,603	24,427	21,559	22,183	35,540	Jun-21	35,540
Hornet		14,202	14,675	15,186	11,080	11,212	11,725	10,749	11,078	11,302	9,782	12,038	17,381	Jun-21	17,381
Independence		20,973	20,513	20,528	16,619	16,946	17,814	18,428	18,988	17,258	15,311	16,531	23,969	Jun-21	23,969
Jacksonville		17,113	17,686	16,720	12,121	14,458	15,057	15,130	14,651	14,060	11,879	13,446	20,264	Jun-21	20,264
Jefferson		8,746	8,793	8,954	9,860	10,413	10,759	10,812	11,209	11,031	10,119	9,887	11,758	Jun-21	11,758
Jerome Prairie		13,368	13,369	12,599	13,313	15,905	15,708	14,381	14,854	15,015	12,636	10,978	15,843	Nov-20	15,905
Junction City		7,763	7,811	7,625	7,943	8,378	8,984	8,821	8,988	8,615	7,580	6,394	8,346	Feb-21	8,988
Knappa Svensen		2,819	2,932	2,838	3,970	4,378	4,498	5,097	4,934	4,703	4,397	3,074	3,471	Jun-21	5,097
Knott		19,580	19,551	19,280	21,075	22,311	23,744	28,965	28,967	24,193	21,484	19,631	31,719	Jun-21	31,719
Lakeport		17,426	17,498	18,089	17,113	17,992	18,392	19,825	19,264	19,102	17,296	16,407	18,452	Jun-21	19,825
Lebanon		30,409	30,908	29,183	27,403	27,303	29,540	28,491	29,369	26,880	25,003	23,760	35,795	Jun-21	35,795
Lincoln		19,347	19,587	18,748	17,973	17,352	17,623	18,885	21,055	18,625	17,424	16,173	22,534	Jun-21	22,534
Lockhart		10,960	12,975	11,462	17,800	20,068	21,649	21,351	21,406	21,756	20,086	14,491	12,029	Mar-21	21,756
Lyon		17,240	17,191	16,176	17,441	18,834	19,023	20,354	19,864	19,953	19,209	17,797	18,398	Jun-21	20,354
Madras		18,495	16,566	16,684	17,490	17,046	17,973	19,540	20,260	16,932	16,669	14,600	21,203	Jun-21	21,203
Mallory		13,173	12,4												





PacifiCorp  
Oregon Marginal Cost Study  
Allocation of Uncollectible Expense between Members of Class  
12 Months Ended December 2023

Line	Description	(A) Del. Volt	(B) Revenues <u>December 2021</u>		(D) Percent of <u>Total Revenues</u>		(F) <u>Allocated Net Uncollectible</u>		(H) Total
			Commercial	Industrial	Commercial	Industrial	Commercial	Industrial	
1	Res - Sch 4	(sec)	-	-	0.00%	0.00%	\$0	\$0	\$2,229,536
2									
3	GS - Sch 23	(sec)	\$122,318,322	\$1,787,870	24.27%	1.74%	\$91,754	-\$1,142	\$90,612
4	GS - Sch 23	(pri)	\$308,103	\$23,849	0.06%	0.02%	\$231	-\$15	\$216
5	GS - Sch 23	Total	\$122,626,425	\$1,811,719	24.33%	1.76%	\$91,985	-\$1,157	\$90,828
6									
7	GS - Sch 28	(sec)	\$155,110,117	\$6,553,539	30.77%	6.38%	\$116,351	-\$4,186	\$112,166
8	GS - Sch 28	(pri)	\$1,710,536	\$357,902	0.34%	0.35%	\$1,283	-\$229	\$1,055
9	GS - Sch 28	Total	\$156,820,653	\$6,911,441	31.11%	6.73%	\$117,635	-\$4,414	\$113,220
10									
11	GS - Sch 30	(sec)	\$74,329,134	\$12,635,934	14.75%	12.30%	\$55,756	-\$8,071	\$47,685
12	GS - Sch 30	(pri)	\$5,865,104	\$1,366,429	1.16%	1.33%	\$4,400	-\$873	\$3,527
13	GS - Sch 30	Total	\$80,194,238	\$14,002,363	15.91%	13.63%	\$60,155	-\$8,944	\$51,212
14									
15	LPS - Sch 48	(sec)	\$25,482,818	\$15,495,788	5.06%	15.09%	\$19,115	-\$9,897	\$9,218
16	LPS - Sch 48	(pri)	\$32,840,740	\$63,186,011	6.52%	61.52%	\$24,635	-\$40,358	-\$15,723
17	LPS - Sch 48	(trn)	\$86,098,155	\$1,296,586	17.08%	1.26%	\$64,584	-\$828	\$63,756
18	LPS - Sch 48	Total	\$144,421,713	\$79,978,385	28.65%	77.87%	\$108,334	-\$51,084	\$57,250
19									
20	Irg - Sch 41	(sec)	-	\$29,193,816	0.00%	100.00%	\$0	\$15,617	\$15,617
21			-	\$29,193,816	0.00%	100.00%	\$0	\$15,617	\$15,617
22									
23	Total		\$504,063,029	\$131,897,724			\$378,109	-\$49,982	\$2,557,663

12 Months Ended June 2021	
Net Write-offs	
Residential	\$2,229,536
Commercial	\$378,109
Industrial	-\$65,599
Irrigation	\$15,617
Total	2,557,663

Docket No. UE 399  
Exhibit PAC/1109  
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Robert M. Meredith  
Target Functionalized Revenues, Billing Determinants and Proposed Rates**

**March 2022**

**PACIFIC POWER  
STATE OF OREGON  
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues  
Forecast 12 Months Ended December 31, 2023**

Rate Schedule	Present Revenues (\$000)	Cost of Service Revenues (\$000)	Target with Unadjusted NPC Revenues (\$000)	Summary of Proposed Functionalized Revenues (\$000)	
					(1)
<b>Schedule 4, Residential</b>					
Transmission & Ancillary Services <sup>1</sup>	\$46,085	\$51,736	\$51,736	\$51,719	
System Usage- Schedule 200 Related	\$3,775	\$3,736	\$3,736	\$3,718	
System Usage- T&A and Schedule 201 Related	\$4,451	\$4,618	\$4,618	\$4,620	
Distribution	\$257,562	\$321,705	\$321,705	\$321,735	
Other Adjustments	\$1,282	\$0	\$0	\$0	
Generation Energy - Other (non-NPC) (Sch 200)	\$160,615	\$166,946	\$166,946	\$166,940	
Generation Energy - Net Power Costs (Sch 201)	\$123,294	\$154,626	\$123,294	\$123,294	
<b>Total</b>	<b>\$597,063</b>	<b>\$703,367</b>	<b>\$672,036</b>	<b>\$672,026</b>	
<b>Schedule 23, Small General Service</b>					
Transmission & Ancillary Services <sup>1</sup>	\$8,220	\$8,867	\$8,867	\$8,868	
System Usage- Schedule 200 Related	\$694	\$728	\$728	\$728	
System Usage- T&A and Schedule 201 Related	\$819	\$878	\$878	\$875	
Distribution	\$60,110	\$71,409	\$71,409	\$71,406	
Other Adjustments	\$247	\$0	\$0	\$0	
Generation Energy - Other (non-NPC) (Sch 200)	\$30,769	\$31,741	\$31,741	\$31,744	
Generation Energy - Net Power Costs (Sch 201)	\$23,580	\$29,398	\$23,580	\$23,580	
<b>Total</b>	<b>\$124,438</b>	<b>\$143,021</b>	<b>\$137,203</b>	<b>\$137,202</b>	
<b>Schedule 28, General Service 31-200kW</b>					
Secondary Voltage					
Transmission & Ancillary Services <sup>1</sup>	\$15,275	\$14,801	\$14,801	\$14,789	
System Usage- Schedule 200 Related	\$1,339	\$1,363	\$1,363	\$1,358	
System Usage- T&A and Schedule 201 Related	\$1,555	\$1,634	\$1,634	\$1,634	
Distribution	\$48,399	\$47,426	\$47,426	\$47,440	
Other Adjustments	\$433	\$0	\$0	\$0	
Generation Energy - Other (non-NPC) (Sch 200)	\$53,582	\$54,271	\$54,271	\$54,271	
Generation Energy - Net Power Costs (Sch 201)	\$41,082	\$50,266	\$41,082	\$41,082	
<b>Total</b>	<b>\$161,664</b>	<b>\$169,761</b>	<b>\$160,576</b>	<b>\$160,573</b>	
Primary Voltage					
Transmission & Ancillary Services <sup>1</sup>	\$220	\$172	\$172	\$172	
System Usage- Schedule 200 Related	\$15	\$18	\$18	\$18	
System Usage- T&A and Schedule 201 Related	\$18	\$22	\$22	\$22	
Distribution	\$676	\$471	\$471	\$471	
Other Adjustments	\$5	\$0	\$0	\$0	
Generation Energy - Other (non-NPC) (Sch 200)	\$642	\$641	\$641	\$641	
Generation Energy - Net Power Costs (Sch 201)	\$492	\$594	\$492	\$492	
<b>Total</b>	<b>\$2,068</b>	<b>\$1,918</b>	<b>\$1,817</b>	<b>\$1,817</b>	
<b>Schedule 30, General Service 201-999kW</b>					
Secondary Voltage					
Transmission & Ancillary Services <sup>1</sup>	\$8,377	\$8,381	\$8,381	\$8,377	
System Usage- Schedule 200 Related	\$769	\$810	\$810	\$805	
System Usage- T&A and Schedule 201 Related	\$899	\$963	\$963	\$958	
Distribution	\$21,015	\$18,724	\$18,724	\$18,752	
Other Adjustments	\$248	\$0	\$0	\$0	
Generation Energy - Other (non-NPC) (Sch 200)	\$31,568	\$31,981	\$31,981	\$31,976	
Generation Energy - Net Power Costs (Sch 201)	\$24,089	\$29,621	\$24,089	\$24,089	
<b>Total</b>	<b>\$86,965</b>	<b>\$90,480</b>	<b>\$84,948</b>	<b>\$84,957</b>	
Primary Voltage					
Transmission & Ancillary Services <sup>1</sup>	\$700	\$713	\$713	\$711	
System Usage- Schedule 200 Related	\$63	\$68	\$68	\$68	
System Usage- T&A and Schedule 201 Related	\$75	\$81	\$81	\$81	
Distribution	\$1,715	\$1,475	\$1,475	\$1,483	
Other Adjustments	\$22	\$0	\$0	\$0	
Generation Energy - Other (non-NPC) (Sch 200)	\$2,621	\$2,652	\$2,652	\$2,645	
Generation Energy - Net Power Costs (Sch 201)	\$2,036	\$2,456	\$2,036	\$2,036	
<b>Total</b>	<b>\$7,232</b>	<b>\$7,445</b>	<b>\$7,024</b>	<b>\$7,024</b>	
<b>Schedule 41, Agricultural Pumping Service</b>					
Transmission & Ancillary Services <sup>1</sup>	\$1,695	\$1,788	\$1,788	\$1,787	
System Usage- Schedule 200 Related	\$150	\$177	\$177	\$177	
System Usage- T&A and Schedule 201 Related	\$235	\$150	\$150	\$150	
Distribution	\$15,064	\$20,423	\$20,423	\$20,425	
Other Adjustments	\$55	\$0	\$0	\$0	
Generation Energy - Other (non-NPC) (Sch 200)	\$6,792	\$7,027	\$7,027	\$7,027	
Generation Energy - Net Power Costs (Sch 201)	\$5,203	\$6,508	\$5,203	\$5,203	
<b>Total</b>	<b>\$29,194</b>	<b>\$36,073</b>	<b>\$34,767</b>	<b>\$34,768</b>	

**PACIFIC POWER  
STATE OF OREGON  
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues  
Forecast 12 Months Ended December 31, 2023**

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)
<b>Schedule 48, Large General Service, 1,000kW and over</b>				
Secondary Voltage				
Transmission & Ancillary Services <sup>1</sup>	\$3,789	\$3,774	\$3,774	\$3,775
System Usage- Schedule 200 Related	\$328	\$369	\$369	\$371
System Usage- T&A and Schedule 201 Related	\$382	\$437	\$437	\$437
Distribution	\$10,763	\$10,112	\$10,112	\$10,115
Other Adjustments	\$118	\$0	\$0	\$0
Generation Energy - Other (non-NPC) (Sch 200)	\$14,485	\$14,640	\$14,640	\$14,633
Generation Energy - Net Power Costs (Sch 201)	\$11,114	\$13,560	\$11,114	\$11,114
<b>Total</b>	<b>\$40,979</b>	<b>\$42,891</b>	<b>\$40,445</b>	<b>\$40,445</b>
Primary Voltage				
Transmission & Ancillary Services <sup>1</sup>	\$9,315	\$9,326	\$9,326	\$9,315
System Usage- Schedule 200 Related	\$864	\$950	\$950	\$952
System Usage- T&A and Schedule 201 Related	\$996	\$1,114	\$1,114	\$1,113
Distribution	\$18,811	\$16,580	\$16,580	\$16,594
Other Adjustments	\$302	\$0	\$0	\$0
Generation Energy - Other (non-NPC) (Sch 200)	\$37,235	\$37,871	\$37,871	\$37,870
Generation Energy - Net Power Costs (Sch 201)	\$28,504	\$35,076	\$28,504	\$28,504
<b>Total</b>	<b>\$96,027</b>	<b>\$100,917</b>	<b>\$94,345</b>	<b>\$94,348</b>
Transmission Voltage				
Transmission & Ancillary Services <sup>1</sup>	\$9,388	\$9,035	\$9,035	\$9,041
System Usage- Schedule 200 Related	\$896	\$951	\$951	\$958
System Usage- T&A and Schedule 201 Related	\$1,020	\$1,105	\$1,105	\$1,113
Distribution	\$10,364	\$7,923	\$7,923	\$7,911
Other Adjustments	\$294	\$0	\$0	\$0
Generation Energy - Other (non-NPC) (Sch 200)	\$37,159	\$38,234	\$38,234	\$38,225
Generation Energy - Net Power Costs (Sch 201)	\$28,274	\$35,413	\$28,274	\$28,274
<b>Total</b>	<b>\$87,395</b>	<b>\$92,661</b>	<b>\$85,522</b>	<b>\$85,523</b>
<b>Schedules 15, 51, 53, 54 Lighting</b>				
Secondary Voltage				
Transmission & Ancillary Services <sup>1</sup>	\$39	\$28	\$28	\$28
System Usage- Schedule 200 Related	\$15	\$14	\$14	\$14
System Usage- T&A and Schedule 201 Related	\$14	\$13	\$13	\$14
Distribution	\$4,102	\$3,634	\$3,634	\$3,633
Other Adjustments	\$4	\$0	\$0	\$0
Generation Energy - Other (non-NPC) (Sch 200)	\$567	\$457	\$457	\$458
Generation Energy - Net Power Costs (Sch 201)	\$410	\$424	\$410	\$410
<b>Total</b>	<b>\$5,151</b>	<b>\$4,569</b>	<b>\$4,556</b>	<b>\$4,558</b>
<b>TOTAL</b>	<b>\$1,238,175</b>	<b>\$1,393,104</b>	<b>\$1,323,240</b>	<b>\$1,323,240</b>
Employee Discount	-\$341		-\$383	-\$383
Additional Rate Schedules				
Schedule 47	\$3,974		\$3,782	\$3,782
Schedule 848	\$1,805		\$1,374	\$1,374
<b>Total Oregon</b>	<b>\$1,243,614</b>		<b>\$1,328,013</b>	<b>\$1,328,013</b>
		<b>Revenue Increase</b>	<b>\$84,399</b>	<b>\$84,400</b>

<sup>1</sup>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, 2021  
Forecast 12 Months Ended December 31, 2023

Schedule	Actual	Normalized	Forecast	Present		Proposed	
	7/20-6/21 Units	7/20-6/21 Units	1/23 - 12/23 Units	Price	Dollars	Price	Dollars
<b>Schedule No. 4</b>							
<b>Residential Service</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kWh	5,769,399,104	5,755,783,167	5,633,856,479 kWh	0.818 ¢	\$46,084,946	0.918 ¢	\$51,718,802
<b>System Usage Charge</b>							
Sch 200 related, per kWh	5,769,399,104	5,755,783,167	5,633,856,479 kWh	0.067 ¢	\$3,774,684	0.066 ¢	\$3,718,345
T&A and Sch 201 related, per kWh	5,769,399,104	5,755,783,167	5,633,856,479 kWh	0.079 ¢	\$4,450,747	0.082 ¢	\$4,619,762
<b>Distribution Charge</b>							
Basic Charge Single Family, per month	4,970,309	4,970,309	5,116,973 bill	\$9.50	\$48,611,244	\$12.00	\$61,403,676
Basic Charge Multi Family, per month	1,266,367	1,266,367	1,303,735 bill	\$8.00	\$10,429,880	\$8.00	\$10,429,880
Total Bills	6,236,676	6,236,676	6,420,708 bill				
Three Phase Demand Charge, per kW demand	16,025	16,025	15,686 kW	\$2.20	\$34,509	\$2.20	\$34,509
Three Phase Minimum Demand Charge, per month	1,373	1,373	1,414 bill	\$3.80	\$5,373	\$3.80	\$5,373
Distribution Energy Charge, per kWh	5,769,399,104	5,755,783,167	5,633,856,479 kWh	3.523 ¢	\$198,480,764	4.435 ¢	\$249,861,535
<b>Energy Charge - Schedule 200</b>							
First Block kWh (0-1,000)	4,325,370,839	4,315,161,839	4,223,752,316 kWh	2.732 ¢	\$115,392,913		
Second Block kWh (> 1,000)	1,444,028,265	1,440,621,328	1,410,104,163 kWh	3.207 ¢	\$45,222,041		
Summer kWh			1,572,474,819 kWh			3.648 ¢	\$57,363,881
Winter kWh			4,061,381,660 kWh			2.698 ¢	\$109,576,077
<b>Subtotal</b>	5,769,399,104	5,755,783,167	5,633,856,479 kWh		\$472,487,101		\$548,731,840
TAM Adj for Other Revs (205)							
First Block kWh (0-1,000)	4,325,370,839	4,315,161,839	4,223,752,316 kWh	0.021 ¢	\$886,988	0.000 ¢	\$0
Second Block kWh (> 1,000)	1,444,028,265	1,440,621,328	1,410,104,163 kWh	0.028 ¢	\$394,829	0.000 ¢	\$0
<b>Subtotal</b>					\$473,768,918		\$548,731,840
<b>Schedule 201</b>							
First Block kWh (0-1,000)	4,325,370,839	4,315,161,839	4,223,752,316 kWh	2.016 ¢	\$85,150,847	2.016 ¢	\$85,150,847
Second Block kWh (> 1,000)	1,444,028,265	1,440,621,328	1,410,104,163 kWh	2.705 ¢	\$38,143,318	2.705 ¢	\$38,143,318
<b>Total</b>	5,769,399,104	5,755,783,167	5,633,856,479 kWh		\$597,063,083		\$672,026,005
						Change	\$74,962,922
<b>Schedule No. 4 (Employee Discount)</b>							
<b>Residential Service</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kWh	13,311,491	13,311,491	13,029,509 kWh	0.818 ¢	\$106,581	0.918 ¢	\$119,611
<b>System Usage Charge</b>							
Sch 200 related, per kWh	13,311,491	13,311,491	13,029,509 kWh	0.067 ¢	\$8,730	0.066 ¢	\$8,599
T&A and Sch 201 related, per kWh	13,311,491	13,311,491	13,029,509 kWh	0.079 ¢	\$10,293	0.082 ¢	\$10,684
<b>Distribution Charge</b>							
Basic Charge Single Family, per month	10,775	10,775	11,093 bill	\$9.50	\$105,384	\$12.00	\$133,116
Basic Charge Multi Family, per month	480	480	494 bill	\$8.00	\$3,952	\$8.00	\$3,952
Total Bills	11,255	11,255	11,587 bill				
Three Phase Demand Charge, per kW demand	0	0	0 kW	\$2.20	\$0	\$2.20	\$0
Three Phase Minimum Demand Charge, per month	0	0	0 bill	\$3.80	\$0	\$3.80	\$0
Distribution Energy Charge, per kWh	13,311,491	13,311,491	13,029,509 kWh	3.523 ¢	\$459,030	4.435 ¢	\$577,859
<b>Energy Charge - Schedule 200</b>							
First Block kWh (0-1,000)	9,240,455	9,240,455	9,044,711 kWh	2.732 ¢	\$247,102		
Second Block kWh (> 1,000)	4,071,036	4,071,036	3,984,798 kWh	3.207 ¢	\$127,792		
Summer kWh			3,636,687 kWh			3.648 ¢	\$132,666
Winter kWh			9,392,822 kWh			2.698 ¢	\$253,418
<b>Subtotal</b>	13,311,491	13,311,491	13,029,509 kWh		\$1,068,864		\$1,239,905
TAM Adj for Other Revs (205)							
First Block kWh (0-1,000)	9,240,455	9,240,455	9,044,711 kWh	0.021 ¢	\$1,899	0.000 ¢	\$0
Second Block kWh (> 1,000)	4,071,036	4,071,036	3,984,798 kWh	0.028 ¢	\$1,116	0.000 ¢	\$0
<b>Subtotal</b>					\$1,071,879		\$1,239,905
<b>Schedule 201</b>							
First Block kWh (0-1,000)	9,240,455	9,240,455	9,044,711 kWh	2.016 ¢	\$182,341	2.016 ¢	\$182,341
Second Block kWh (> 1,000)	4,071,036	4,071,036	3,984,798 kWh	2.705 ¢	\$107,789	2.705 ¢	\$107,789
<b>Total</b>	13,311,491	13,311,491	13,029,509 kWh		\$1,362,009		\$1,530,035
Schedule 201 Employee Discount					(\$72,533)		(\$72,533)
<b>Total Employee Discount</b>					(\$340,502)		(\$382,509)
						Change	(\$42,007)

**PACIFIC POWER**  
**State of Oregon**  
**Billing Determinants**  
**Actual 12 Months Ended June 30, 2021**  
**Forecast 12 Months Ended December 31, 2023**

Schedule	Actual	Normalized	Forecast	Present		Proposed	
	7/20-6/21 Units	7/20-6/21 Units	1/23 - 12/23 Units	Price	Dollars	Price	Dollars
<b>Schedule No. 23/723 - Composite</b>							
<b>General Service (Secondary)</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kWh	1,179,290,680	1,169,546,266	1,133,686,986 kWh	0.723 ¢	\$8,196,557	0.780 ¢	\$8,842,758
<b>System Usage Charge</b>							
Sch 200 related, per kWh	1,179,290,680	1,169,546,266	1,133,686,986 kWh	0.061 ¢	\$691,549	0.064 ¢	\$725,560
T&A and Sch 201 related, per kWh	1,179,290,680	1,169,546,266	1,133,686,986 kWh	0.072 ¢	\$816,255	0.077 ¢	\$872,939
<b>Distribution Charge</b>							
<b>Basic Charge</b>							
Single Phase, per month	775,694	775,694	775,779 bill	\$17.35	\$13,459,766	\$17.35	\$13,459,766
Three Phase, per month	240,969	240,969	239,153 bill	\$25.90	\$6,194,063	\$25.90	\$6,194,063
<b>Load Size Charge</b>							
≤ 15 kW				No Charge		No Charge	
per kW for all kW in excess of 15 kW	1,142,229	1,142,229	1,106,759 kW	\$1.40	\$1,549,463	\$1.65	\$1,826,152
<b>Demand Charge, the first 15 kW of demand</b>							
Demand Charge, per kW for all kW in excess of 15 kW	564,595	564,595	547,081 kW	\$4.64	\$2,538,456	\$5.51	\$3,014,416
Reactive Power Charge, per kvar	216,881	216,881	209,593 kvar	65.00 ¢	\$136,235	65.00 ¢	\$136,235
Distribution Energy Charge, per kWh	1,179,290,680	1,169,546,266	1,133,686,986 kWh	3.182 ¢	\$36,073,920	4.109 ¢	\$46,583,198
<b>Energy Charge - Schedule 200</b>							
1st 3,000 kWh, per kWh	924,695,576	917,115,576	889,068,833 kWh	2.866 ¢	\$25,480,713	2.957 ¢	\$26,289,765
All additional kWh, per kWh	254,595,104	252,430,690	244,618,153 kWh	2.128 ¢	\$5,205,474	2.195 ¢	\$5,369,368
<b>Subtotal</b>	1,179,290,680	1,169,546,266	1,133,686,986 kWh		\$100,342,451		\$113,314,220
<b>TAM Adj for Other Revs (205)</b>							
1st 3,000 kWh, per kWh	924,695,576	917,115,576	889,068,833 kWh	0.023 ¢	\$204,486	0.000 ¢	\$0
All additional kWh, per kWh	254,595,104	252,430,690	244,618,153 kWh	0.017 ¢	\$41,585	0.000 ¢	\$0
<b>Subtotal</b>					\$100,588,522		\$113,314,220
<b>Schedule 201</b>							
1st 3,000 kWh, per kWh	924,695,576	917,115,576	889,068,833 kWh	2.197 ¢	\$19,532,842	2.197 ¢	\$19,532,842
All additional kWh, per kWh	254,595,104	252,430,690	244,618,153 kWh	1.629 ¢	\$3,984,830	1.629 ¢	\$3,984,830
<b>Total</b>	1,179,290,680	1,169,546,266	1,133,686,986 kWh		\$124,106,194	Change	\$136,831,892
							\$12,725,698
<b>Schedule No. 23/723 - Composite</b>							
<b>General Service (Primary)</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kWh	3,442,654	3,442,654	3,323,737 kWh	0.712 ¢	\$23,665	0.768 ¢	\$25,526
<b>System Usage Charge</b>							
Sch 200 related, per kWh	3,442,654	3,442,654	3,323,737 kWh	0.060 ¢	\$1,994	0.063 ¢	\$2,094
T&A and Sch 201 related, per kWh	3,442,654	3,442,654	3,323,737 kWh	0.071 ¢	\$2,360	0.076 ¢	\$2,526
<b>Distribution Charge</b>							
<b>Basic Charge</b>							
Single Phase, per month	685	685	682 bill	\$17.35	\$11,833	\$17.35	\$11,833
Three Phase, per month	703	703	697 bill	\$25.90	\$18,052	\$25.90	\$18,052
<b>Load Size Charge</b>							
≤ 15 kW				No Charge		No Charge	
per kW for all kW in excess of 15 kW	7,379	7,379	7,143 kW	\$1.40	\$10,000	\$1.65	\$11,786
<b>Demand Charge, the first 15 kW of demand</b>							
Demand Charge, per kW for all kW in excess of 15 kW	2,821	2,821	2,732 kW	\$4.58	\$12,513	\$5.44	\$14,862
Reactive Power Charge, per kvar	2,717	2,717	2,599 kvar	60.00 ¢	\$1,559	60.00 ¢	\$1,559
Distribution Energy Charge, per kWh	3,442,654	3,442,654	3,323,737 kWh	3.133 ¢	\$104,133	4.045 ¢	\$134,445
<b>Energy Charge - Schedule 200</b>							
1st 3,000 kWh, per kWh	1,866,264	1,866,264	1,804,482 kWh	2.822 ¢	\$50,922	2.911 ¢	\$52,528
All additional kWh, per kWh	1,576,390	1,576,390	1,519,255 kWh	2.095 ¢	\$31,828	2.161 ¢	\$32,831
<b>Subtotal</b>	3,442,654	3,442,654	3,323,737 kWh		\$268,859		\$308,042
<b>TAM Adj for Other Revs (205)</b>							
1st 3,000 kWh, per kWh	1,866,264	1,866,264	1,804,482 kWh	0.022 ¢	\$397	0.000 ¢	\$0
All additional kWh, per kWh	1,576,390	1,576,390	1,519,255 kWh	0.017 ¢	\$258	0.000 ¢	\$0
<b>Subtotal</b>					\$269,514		\$308,042
<b>Schedule 201</b>							
1st 3,000 kWh, per kWh	1,866,264	1,866,264	1,804,482 kWh	2.130 ¢	\$38,435	2.130 ¢	\$38,435
All additional kWh, per kWh	1,576,390	1,576,390	1,519,255 kWh	1.580 ¢	\$24,004	1.580 ¢	\$24,004
<b>Total</b>	3,442,654	3,442,654	3,323,737 kWh		\$331,953	Change	\$370,481
							\$38,528

**PACIFIC POWER**  
State of Oregon  
Billing Determinants  
Actual 12 Months Ended June 30, 2021  
Forecast 12 Months Ended December 31, 2023

Schedule	Actual	Normalized	Forecast	Present		Proposed		
	7/20-6/21 Units	7/20-6/21 Units	1/23 - 12/23 Units	Price	Dollars	Price	Dollars	
<b>Schedule No. 28/728 - Composite</b>								
<b>Large General Service - (Secondary)</b>								
<b>Transmission &amp; Ancillary Services Charge</b>								
per kW	6,972,158	6,972,158	6,943,054	kW	\$2.20	\$15,274,719	\$2.13	\$14,788,705
<b>System Usage Charge</b>								
Sch 200 related, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	0.068 ¢	\$1,338,557	0.069 ¢	\$1,358,242
T&A and Sch 201 related, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	0.079 ¢	\$1,555,088	0.083 ¢	\$1,633,827
<b>Distribution Charge</b>								
<b>Basic Charge</b>								
Load Size ≤ 50 kW, per month	58,555	58,555	59,595	bill	\$19.00	\$1,132,305	\$19.00	\$1,132,305
Load Size 51-100 kW, per month	41,184	41,184	41,899	bill	\$35.00	\$1,466,465	\$34.00	\$1,424,566
Load Size 101-300 kW, per month	22,209	22,209	22,586	bill	\$84.00	\$1,897,224	\$82.00	\$1,852,052
Load Size > 300 kW, per month	621	621	631	bill	\$119.00	\$75,089	\$117.00	\$73,827
<b>Load Size Charge</b>								
≤ 50 kW, per kW	2,232,934	2,232,934	2,227,010	kW	\$1.20	\$2,672,412	\$1.20	\$2,672,412
51-100 kW, per kW	2,892,150	2,892,150	2,879,942	kW	\$0.95	\$2,735,945	\$0.95	\$2,735,945
101-300 kW, per kW	3,353,010	3,353,010	3,336,352	kW	\$0.55	\$1,834,994	\$0.55	\$1,834,994
>300 kW, per kW	259,546	259,546	257,628	kW	\$0.35	\$90,170	\$0.35	\$90,170
Demand Charge, per kW	6,972,158	6,972,158	6,943,054	kW	\$4.03	\$27,980,508	\$3.95	\$27,425,063
Reactive Power Charge, per kvar	657,847	657,847	651,033	kvar	65.00 ¢	\$423,171	65.00 ¢	\$423,171
Distribution Energy Charge, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	0.411 ¢	\$8,090,397	0.395 ¢	\$7,775,442
<b>Energy Charge - Schedule 200</b>								
All kWh, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	2.722 ¢	\$53,581,657	2.757 ¢	\$54,270,620
<b>Subtotal</b>	1,993,362,624	1,975,519,401	1,968,466,445	kWh		\$120,148,701		\$119,491,341
TAM Adj for Other Revs (205)								
All kWh, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	0.022 ¢	\$433,063	0.000 ¢	\$0
<b>Subtotal</b>						\$120,581,764		\$119,491,341
Schedule 201								
All kWh, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	2.087 ¢	\$41,081,895	2.087 ¢	\$41,081,895
<b>Total</b>	1,993,362,624	1,975,519,401	1,968,466,445	kWh		\$161,663,659		\$160,573,236
							Change	(\$1,090,423)
<b>Schedule No. 28/728 - Composite</b>								
<b>Large General Service - (Primary)</b>								
<b>Transmission &amp; Ancillary Services Charge</b>								
per kW	104,177	104,177	102,993	kW	\$2.14	\$220,405	\$1.67	\$171,998
<b>System Usage Charge</b>								
Sch 200 related, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.064 ¢	\$15,235	0.077 ¢	\$18,329
T&A and Sch 201 related, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.075 ¢	\$17,853	0.091 ¢	\$21,662
<b>Distribution Charge</b>								
<b>Basic Charge</b>								
Load Size ≤ 50 kW, per month	164	164	167	bill	\$25.00	\$4,175	\$17.00	\$2,839
Load Size 51-100 kW, per month	214	214	217	bill	\$43.00	\$9,331	\$30.00	\$6,510
Load Size 101-300 kW, per month	380	380	385	bill	\$100.00	\$38,500	\$70.00	\$26,950
Load Size > 300 kW, per month	54	54	55	bill	\$143.00	\$7,865	\$100.00	\$5,500
<b>Load Size Charge</b>								
≤ 50 kW, per kW	6,569	6,569	6,511	kW	\$1.40	\$9,115	\$1.00	\$6,511
51-100 kW, per kW	15,968	15,968	15,692	kW	\$1.15	\$18,046	\$0.80	\$12,554
101-300 kW, per kW	66,331	66,331	65,414	kW	\$0.70	\$45,790	\$0.50	\$32,707
>300 kW, per kW	43,318	43,318	42,282	kW	\$0.35	\$14,799	\$0.25	\$10,571
Demand Charge, per kW	104,177	104,177	102,993	kW	\$4.90	\$504,666	\$3.42	\$352,236
Reactive Power Charge, per kvar	11,812	11,812	11,603	kvar	60.00 ¢	\$6,962	60.00 ¢	\$6,962
Distribution Energy Charge, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.069 ¢	\$16,425	0.034 ¢	\$8,093
<b>Energy Charge - Schedule 200</b>								
All kWh, per kWh	24,061,378	24,061,378	23,804,268	kWh	2.696 ¢	\$641,763	2.693 ¢	\$641,049
<b>Subtotal</b>	24,061,378	24,061,378	23,804,268	kWh		\$1,570,930		\$1,324,471
TAM Adj for Other Revs (205)								
All kWh, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.022 ¢	\$5,237	0.000 ¢	\$0
<b>Subtotal</b>						\$1,576,167		\$1,324,471
Schedule 201								
All kWh, per kWh	24,061,378	24,061,378	23,804,268	kWh	2.068 ¢	\$492,272	2.068 ¢	\$492,272
<b>Total</b>	24,061,378	24,061,378	23,804,268	kWh		\$2,068,439		\$1,816,743
							Change	(\$251,696)

**PACIFIC POWER**  
State of Oregon  
Billing Determinants  
Actual 12 Months Ended June 30, 2021  
Forecast 12 Months Ended December 31, 2023

Schedule	Actual	Normalized	Forecast	Present		Proposed	
	7/20-6/21 Units	7/20-6/21 Units	1/23 - 12/23 Units	Price	Dollars	Price	Dollars
<b>Schedule No. 30/730 - Composite</b>							
<b>Large General Service - (Secondary)</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kW	3,224,408	3,224,408	3,324,307 kW	\$2.52	\$8,377,254	\$2.52	\$8,377,254
<b>System Usage Charge</b>							
Sch 200 related, per kWh	1,152,976,818	1,142,524,024	1,183,141,965 kWh	0.065 ¢	\$769,042	0.068 ¢	\$804,537
T&A and Sch 201 related, per kWh	1,152,976,818	1,142,524,024	1,183,141,965 kWh	0.076 ¢	\$899,188	0.081 ¢	\$958,345
<b>Distribution Charge</b>							
Basic Charge							
Load Size ≤ 200 kW, per month	179	179	176 bill	\$494.00	\$86,944	\$438.00	\$77,088
Load Size 201-300 kW, per month	2,582	2,582	2,539 bill	\$144.00	\$365,616	\$128.00	\$324,992
Load Size > 300 kW, per month	6,313	6,313	6,205 bill	\$380.00	\$2,357,900	\$339.00	\$2,103,495
Load Size Charge							
≤ 200 Kw, per kW				No Charge	\$0	No Charge	\$0
201-300 kW, per kW	669,986	669,986	692,354 kW	\$1.75	\$1,211,620	\$1.55	\$1,073,149
>300 kW, per kW	3,133,877	3,133,877	3,233,216 kW	\$0.85	\$2,748,234	\$0.75	\$2,424,912
Demand Charge, per kW	3,224,408	3,224,408	3,324,307 kW	\$4.17	\$13,862,360	\$3.72	\$12,366,422
Reactive Power Charge, per kvar	581,094	581,094	587,792 kvar	65.00 ¢	\$382,065	65.00 ¢	\$382,065
<b>Energy Charge - Schedule 200</b>							
Demand Charge, per kW	3,224,408	3,224,408	3,324,307 kW	\$3.41	\$11,335,887	\$5.80	\$19,280,981
All kWh, per kWh	1,152,976,818	1,142,524,024	1,183,141,965 kWh	1.710 ¢	\$20,231,728	1.073 ¢	\$12,695,113
<b>Subtotal</b>	<b>1,152,976,818</b>	<b>1,142,524,024</b>	<b>1,183,141,965 kWh</b>		<b>\$62,627,838</b>		<b>\$60,868,353</b>
TAM Adj for Other Revs (205)							
All kWh, per kWh	1,152,976,818	1,142,524,024	1,183,141,965 kWh	0.021 ¢	\$248,460	0.000 ¢	\$0
<b>Subtotal</b>					<b>\$62,876,298</b>		<b>\$60,868,353</b>
Schedule 201							
All kWh, per kWh	1,152,976,818	1,142,524,024	1,183,141,965 kWh	2.036 ¢	\$24,088,770	2.036 ¢	\$24,088,770
<b>Total</b>	<b>1,152,976,818</b>	<b>1,142,524,024</b>	<b>1,183,141,965 kWh</b>		<b>\$86,965,068</b>		<b>\$84,957,123</b>
						Change	(\$2,007,945)
<b>Schedule No. 30/730 - Composite</b>							
<b>Large General Service - (Primary)</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kW	273,083	273,083	280,081 kW	\$2.50	\$700,203	\$2.54	\$711,406
<b>System Usage Charge</b>							
Sch 200 related, per kWh	95,500,340	95,500,340	98,439,365 kWh	0.064 ¢	\$63,001	0.069 ¢	\$67,923
T&A and Sch 201 related, per kWh	95,500,340	95,500,340	98,439,365 kWh	0.076 ¢	\$74,814	0.082 ¢	\$80,720
<b>Distribution Charge</b>							
Basic Charge							
Load Size ≤ 200 kW, per month	0	0	0 bill	\$481.00	\$0	\$410.00	\$0.00
Load Size 201-300 kW, per month	95	95	93 bill	\$151.00	\$14,043	\$130.00	\$12,090.00
Load Size > 300 kW, per month	546	546	538 bill	\$393.00	\$211,434	\$338.00	\$181,844.00
Load Size Charge							
≤ 200 Kw, per kW				No Charge	\$0	No Charge	\$0
201-300 kW, per kW	25,038	25,038	26,123 kW	\$1.65	\$43,103	\$1.40	\$36,572
>300 kW, per kW	312,218	312,218	320,601 kW	\$0.80	\$256,481	\$0.70	\$224,421
Demand Charge, per kW	273,083	273,083	280,081 kW	\$4.17	\$1,167,938	\$3.59	\$1,005,491
Reactive Power Charge, per kvar	38,218	38,218	37,437 kvar	60.00 ¢	\$22,462	60.00 ¢	\$22,462
<b>Energy Charge - Schedule 200</b>							
Demand Charge, per kW	273,083	273,083	280,081 kW	\$3.41	\$955,076	\$5.80	\$1,624,470
All kWh, per kWh	95,500,340	95,500,340	98,439,365 kWh	1.692 ¢	\$1,665,594	1.037 ¢	\$1,020,816
<b>Subtotal</b>	<b>95,500,340</b>	<b>95,500,340</b>	<b>98,439,365 kWh</b>		<b>\$5,174,149</b>		<b>\$4,988,215</b>
TAM Adj for Other Revs (205)							
All kWh, per kWh	95,500,340	95,500,340	98,439,365 kWh	0.022 ¢	\$21,657	0.000 ¢	\$0
<b>Subtotal</b>					<b>\$5,195,806</b>		<b>\$4,988,215</b>
Schedule 201							
All kWh, per kWh	95,500,340	95,500,340	98,439,365 kWh	2.068 ¢	\$2,035,726	2.068 ¢	\$2,035,726
<b>Total</b>	<b>95,500,340</b>	<b>95,500,340</b>	<b>98,439,365 kWh</b>		<b>\$7,231,532</b>		<b>\$7,023,941</b>
						Change	(\$207,591)



**PACIFIC POWER**  
State of Oregon  
Billing Determinants  
Actual 12 Months Ended June 30, 2021  
Forecast 12 Months Ended December 31, 2023

Schedule	Actual	Normalized	Forecast	Present		Proposed	
	7/20-6/21 Units	7/20-6/21 Units	1/23 - 12/23 Units	Price	Dollars	Price	Dollars
<b>Schedule No. 41/741 - Irrigation</b>							
<b>Agricultural Pumping Service (Secondary)</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kWh	237,425,712	224,330,512	263,527,024 kWh	0.643 ¢	\$1,694,479	0.678 ¢	\$1,786,713
<b>System Usage Charge</b>							
Sch 200 related, per kWh	237,425,712	224,330,512	263,527,024 kWh	0.057 ¢	\$150,210	0.067 ¢	\$176,563
T&A and Sch 201 related, per kWh	237,425,712	224,330,512	263,527,024 kWh	0.089 ¢	\$234,539	0.057 ¢	\$150,210
<b>Distribution Charge</b>							
Basic Charge (billed in November)							
Load Size ≤ 50 kW, or Single Phase Any Size	5,576	5,576	6,786 bill	No Charge	\$0	No Charge	\$0
Three Phase Load Size 51 - 300 kW, per customer	974	974	1,185 bill	\$360.00	\$426,600	\$490.00	\$580,650
Three Phase Load Size > 300 kW, per customer	19	19	23 bill	\$1,420.00	\$32,660	\$1,930.00	\$44,390
Total Customers	6,569	6,569	7,994 bill				
Monthly Bills	42,934	42,934	52,248				
Load Size Charge (billed in November)							
Single Phase Any Size, Three Phase ≤ 50 kW	94,969	94,969	111,563 kW	\$17.10	\$1,907,727	\$17.10	\$1,907,727
Three Phase Load Size 51-300 kW, per kW	86,214	86,214	101,278 kW	\$11.70	\$1,184,953	\$11.70	\$1,184,953
Three Phase Load Size > 300 kW, per kW	8,433	8,433	9,906 kW	\$7.20	\$71,323	\$7.20	\$71,323
Single Phase, Minimum Charge	377	377	459 bill	\$65.00	\$29,835	\$90.00	\$41,310
Three Phase, Minimum Charge	1,457	1,457	1,773 bill	\$105.00	\$186,165	\$140.00	\$248,220
Distribution Energy Charge, per kWh	237,425,712	224,330,512	263,527,024 kWh	4.197 ¢	\$11,060,229	6.140 ¢	\$16,180,559
Reactive Power Charge, per kvar	211,414	211,414	248,354 kvar	65.00 ¢	\$161,430	65.00 ¢	\$161,430
<b>Energy Charge - Schedule 200</b>							
All kWh, per kWh	237,425,712	224,330,512	263,527,024 kWh	2.577 ¢	\$6,791,091	2.666 ¢	\$7,025,630
<b>Subtotal</b>	237,425,712	224,330,512	263,527,024 kWh		\$23,931,241		\$29,559,678
TAM Adj for Other Revs (205)	237,425,712	224,330,512	263,527,024 kWh	0.021 ¢	\$55,341	0.000 ¢	\$0
<b>Subtotal</b>					\$23,986,582		\$29,559,678
Schedule 201							
All kWh, per kWh	237,425,712	224,330,512	263,527,024 kWh	1.974 ¢	\$5,202,023	1.974 ¢	\$5,202,023
Option A Summer On Peak Adder, per On-peak kWh	19,903,136	18,805,380	22,091,180 kWh	4.989 ¢	\$1,102,129	4.989 ¢	\$1,102,129
Option B Summer On Peak Adder, per On-peak kWh	19,465,341	18,391,732	21,605,257 kWh	4.989 ¢	\$1,077,886	4.989 ¢	\$1,077,886
Summer Off Peak Adder, per Off-peak kWh	198,057,235	187,133,400	219,830,587 kWh	-0.992 ¢	(\$2,180,719)	-0.992 ¢	(\$2,180,719)
<b>Total</b>	237,425,712	224,330,512	263,527,024 kWh		\$29,188,605		\$34,761,701
						Change	\$5,573,096
<b>Schedule No. 41/741 - Irrigation</b>							
<b>Agricultural Pumping Service (Primary)</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kWh	32,387	32,387	38,046 kWh	0.633 ¢	\$241	0.668 ¢	\$254
<b>System Usage Charge</b>							
Sch 200 related, per kWh	32,387	32,387	38,046 kWh	0.056 ¢	\$21	0.066 ¢	\$25
T&A and Sch 201 related, per kWh	32,387	32,387	38,046 kWh	0.088 ¢	\$33	0.056 ¢	\$21
<b>Distribution Charge</b>							
Basic Charge (billed in November)							
Load Size ≤ 50 kW, or Single Phase Any Size	2	2	2 bill	No Charge	\$0	No Charge	\$0
Three Phase Load Size 51 - 300 kW, per customer	1	1	1 bill	\$360.00	\$360	\$480.00	\$480
Three Phase Load Size > 300 kW, per customer	0	0	0 bill	\$1,400.00	\$0	\$1,900.00	\$0
Total Customers	3	3	3 bill				
Monthly Bills	24	24	24				
Load Size Charge (billed in November)							
Single Phase Any Size, Three Phase ≤ 50 kW	12	12	14 kW	\$16.90	\$237	\$16.90	\$237
Three Phase Load Size 51-300 kW, per kW	72	72	85 kW	\$11.50	\$978	\$11.50	\$978
Three Phase Load Size > 300 kW, per kW	0	0	0 kW	\$7.10	\$0	\$7.10	\$0
Single Phase, Minimum Charge	0	0	0 bill	\$65.00	\$0	\$90.00	\$0
Three Phase, Minimum Charge	0	0	0 bill	\$105.00	\$0	\$140.00	\$0
Distribution Energy Charge, per kWh	32,387	32,387	38,046 kWh	4.132 ¢	\$1,572	6.045 ¢	\$2,300
Reactive Power Charge, per kvar	81	81	95 kvar	60.00 ¢	\$57	60.00 ¢	\$57
<b>Energy Charge - Schedule 200</b>							
All kWh, per kWh	32,387	32,387	38,046 kWh	2.537 ¢	\$965	2.625 ¢	\$999
<b>Subtotal</b>	32,387	32,387	38,046 kWh		\$4,464		\$5,351
TAM Adj for Other Revs (205)	32,387	32,387	38,046 kWh	0.020 ¢	\$8	0.000 ¢	\$0
<b>Subtotal</b>					\$4,472		\$5,351
Schedule 201							
All kWh, per kWh	32,387	32,387	38,046 kWh	1.943 ¢	\$739	1.943 ¢	\$739
Option A Summer On Peak Adder, per On-peak kWh	2,715	2,715	3,189 kWh	4.989 ¢	\$159	4.989 ¢	\$159
Option B Summer On Peak Adder, per On-peak kWh	2,655	2,655	3,119 kWh	4.989 ¢	\$156	4.989 ¢	\$156
Summer Off Peak Adder, per Off-peak kWh	27,017	27,017	31,737 kWh	-0.992 ¢	(\$315)	-0.992 ¢	(\$315)
<b>Total</b>	32,387	32,387	38,046 kWh		\$5,211		\$6,090
						Change	\$879

**PACIFIC POWER**  
**State of Oregon**  
**Billing Determinants**  
**Actual 12 Months Ended June 30, 2021**  
**Forecast 12 Months Ended December 31, 2023**

Schedule	Actual	Normalized	Forecast	Present		Proposed	
	7/20-6/21 Units	7/20-6/21 Units	1/23 - 12/23 Units	Price	Dollars	Price	Dollars
<b>Schedule No. 47747 - Composite</b>							
<b>Large General Service - Partial Requirement (Primary)</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kW of on-peak demand	85,374	85,374	87,270 kW	\$2.45	\$213,812	\$2.45	\$213,812
credit per kW of on-peak demand (OATT)	0	0	0 kW	(\$2.45)	\$0	(\$2.45)	\$0
<b>System Usage Charge</b>							
Sch 200 related, per kWh	14,646,249	14,646,249	14,971,570 kWh	0.059 ¢	\$8,833	0.065 ¢	\$9,732
T&A and Sch 201 related, per kWh	14,646,249	14,646,249	14,971,570 kWh	0.068 ¢	\$10,181	0.076 ¢	\$11,378
<b>Distribution Charge</b>							
Basic Charge							
Facility Capacity ≤ 4,000 kW, per month	0	0	0 bill	\$550.00	\$0	\$530.00	\$0
Facility Capacity > 4,000 kW, per month	12	12	12 bill	\$1,490.00	\$17,880	\$1,470.00	\$17,640
Facilities Charge							
Facility Capacity ≤ 4,000 kW, per kW	0	0	0 kW	\$1.30	\$0	\$1.25	\$0
Facility Capacity > 4,000 kW, per kW	119,806	119,806	122,467 kW	\$0.85	\$104,097	\$0.85	\$104,097
Demand Charge, per kW of on-peak demand	85,374	85,374	87,270 kW	\$4.33	\$377,879	\$3.65	\$318,536
Reactive Power Charge, per kvar	5,446	5,446	5,567 kvar	60.00 ¢	\$3,340	60.00 ¢	\$3,340
Reactive Hours, per kvarh	12,609,400	12,609,400	12,889,479 kvarh	0.080 ¢	\$10,312	0.080 ¢	\$10,312
Reserves Charges							
Spinning Reserves, per kW of Facility Cap.	119,806	119,806	122,467 kW	\$0.27	\$33,066	\$0.27	\$33,066
Supplemental Reserves, per kW of Facility Cap.	119,806	119,806	122,467 kW	\$0.27	\$33,066	\$0.27	\$33,066
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0 kW	(\$0.27)	\$0	(\$0.27)	\$0
Supplemental Reserves Credit, per kW of Facility Cap.	0	0	0 kW	(\$0.27)	\$0	(\$0.27)	\$0
<b>Energy Charge - Schedule 200</b>							
Demand Charge, per kW of On-Peak demand	85,374	85,374	87,270 kW	\$1.71	\$149,232	\$1.74	\$151,850
On-Peak, per on-peak kWh	6,118,478	6,118,478	6,254,381 kWh	2.179 ¢	\$136,283	2.216 ¢	\$138,597
Off-Peak, per off-peak kWh	8,527,771	8,527,771	8,717,189 kWh	2.179 ¢	\$189,948	2.216 ¢	\$193,173
<b>Unscheduled Energy, per kWh</b>	<b>452,751</b>	<b>452,751</b>	<b>462,808 kWh</b>		<b>\$20,584</b>		<b>\$20,584</b>
<b>Subtotal</b>	<b>15,099,000</b>	<b>15,099,000</b>	<b>15,434,378 kWh</b>		<b>\$1,308,513</b>		<b>\$1,259,183</b>
TAM Adj for Other Revs (205)							
On-Peak, per on-peak kWh	6,118,478	6,118,478	6,254,381 kWh	0.025 ¢	\$1,564	0.000 ¢	\$0
Off-Peak, per off-peak kWh	8,527,771	8,527,771	8,717,189 kWh	0.018 ¢	\$1,569	0.000 ¢	\$0
<b>Subtotal</b>					<b>\$1,311,646</b>		<b>\$1,259,183</b>
Schedule 201							
On-Peak, per on-peak kWh	6,118,478	6,118,478	6,254,381 kWh	2.374 ¢	\$148,479	2.374 ¢	\$148,479
Off-Peak, per off-peak kWh	8,527,771	8,527,771	8,717,189 kWh	1.686 ¢	\$146,972	1.686 ¢	\$146,972
<b>Total</b>	<b>15,099,000</b>	<b>15,099,000</b>	<b>15,434,378 kWh</b>		<b>\$1,607,097</b>		<b>\$1,554,634</b>
						Change	(\$52,463)
<b>Schedule No. 47747 - Composite</b>							
<b>Large General Service - Partial Requirement (Transmission)</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kW of on-peak demand	138,992	138,992	135,695 kW	\$3.25	\$441,009	\$3.11	\$422,011
credit per kW of on-peak demand (OATT)	0	0	0 kW	(\$3.25)	\$0	(\$3.11)	\$0
<b>System Usage Charge</b>							
Sch 200 related, per kWh	12,828,129	12,828,129	12,903,938 kWh	0.058 ¢	\$7,484	0.062 ¢	\$8,000
T&A and Sch 201 related, per kWh	12,828,129	12,828,129	12,903,938 kWh	0.066 ¢	\$8,517	0.072 ¢	\$9,291
<b>Distribution Charge</b>							
Basic Charge							
Facility Capacity ≤ 4,000 kW, per month	24	24	24 bill	\$710.00	\$17,040	\$710.00	\$17,040
Facility Capacity > 4,000 kW, per month	36	36	36 bill	\$1,820.00	\$65,520	\$1,820.00	\$65,520
Facilities Charge							
Facility Capacity ≤ 4,000 kW, per kW	28,166	28,166	28,792 kW	\$1.25	\$35,990	\$1.25	\$35,990
Facility Capacity > 4,000 kW, per kW	311,273	311,273	298,765 kW	\$1.05	\$313,703	\$1.05	\$313,703
Demand Charge, per kW of on-peak demand	138,992	138,992	135,695 kW	\$3.03	\$411,156	\$2.04	\$276,818
Reactive Power Charge, per kvar	144,234	144,234	137,544 kvar	55.00 ¢	\$75,649	55.00 ¢	\$75,649
Reactive Hours, per kvarh	48,770,928	48,770,928	45,614,133 kvarh	0.080 ¢	\$36,491	0.080 ¢	\$36,491
Reserves Charges							
Spinning Reserves, per kW of Facility Cap.	339,439	339,439	327,557 kW	\$0.27	\$88,440	\$0.27	\$88,440
Supplemental Reserves, per kW of Facility Cap.	339,439	339,439	327,557 kW	\$0.27	\$88,440	\$0.27	\$88,440
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0 kW	(\$0.27)	\$0	(\$0.27)	\$0
Supplemental Reserves Credit, per kW of Facility Cap.	0	0	0 kW	(\$0.27)	\$0	(\$0.27)	\$0
<b>Energy Charge - Schedule 200</b>							
Demand Charge, per kW of On-Peak demand	138,992	138,992	135,695 kW	\$1.72	\$233,395	\$1.77	\$240,180
On-Peak, per on-peak kWh	4,632,668	4,632,668	4,661,426 kWh	2.129 ¢	\$99,242	2.190 ¢	\$102,085
Off-Peak, per off-peak kWh	8,195,461	8,195,461	8,242,512 kWh	2.129 ¢	\$175,483	2.190 ¢	\$180,511
<b>Unscheduled Energy, per kWh</b>	<b>808,775</b>	<b>808,775</b>	<b>770,332 kWh</b>		<b>\$31,982</b>		<b>\$31,982</b>
<b>Subtotal</b>	<b>13,636,904</b>	<b>13,636,904</b>	<b>13,674,270 kWh</b>		<b>\$2,129,541</b>		<b>\$1,992,151</b>
TAM Adj for Other Revs (205)							
On-Peak, per on-peak kWh	4,632,668	4,632,668	4,661,426 kWh	0.024 ¢	\$1,119	0.000 ¢	\$0
Off-Peak, per off-peak kWh	8,195,461	8,195,461	8,242,512 kWh	0.016 ¢	\$1,319	0.000 ¢	\$0
<b>Subtotal</b>					<b>\$2,131,979</b>		<b>\$1,992,151</b>
Schedule 201							
On-Peak, per on-peak kWh	4,632,668	4,632,668	4,661,426 kWh	2.259 ¢	\$105,302	2.259 ¢	\$105,302
Off-Peak, per off-peak kWh	8,195,461	8,195,461	8,242,512 kWh	1.571 ¢	\$129,490	1.571 ¢	\$129,490
<b>Total</b>	<b>13,636,904</b>	<b>13,636,904</b>	<b>13,674,270 kWh</b>		<b>\$2,366,771</b>		<b>\$2,226,943</b>
						Change	(\$139,828)

**PACIFIC POWER**  
**State of Oregon**  
**Billing Determinants**  
**Actual 12 Months Ended June 30, 2021**  
**Forecast 12 Months Ended December 31, 2023**

Schedule	Actual	Normalized	Forecast	Present		Proposed	
	7/20-6/21 Units	7/20-6/21 Units	1/23 - 12/23 Units	Price	Dollars	Price	Dollars
<b>Schedule No. 76R/776R</b>							
<b>Large General Service/Partial Requirements Service - Economic Replacement Power Rider</b>							
Transmission & Ancillary Services Charge, per kW of Daily ERP On-Peak Demand							
Secondary	0	0	0 kW	\$0.087	\$0	\$0.087	\$0
Primary	0	0	0 kW	\$0.095	\$0	\$0.095	\$0
Transmission	0	0	0 kW	\$0.127	\$0	\$0.121	\$0
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand							
Secondary	0	0	0 kW	\$0.161	\$0	\$0.133	\$0
Primary	0	0	0 kW	\$0.169	\$0	\$0.142	\$0
Transmission	0	0	0 kW	\$0.118	\$0	\$0.079	\$0
<b>Schedule No. 48/748 - Composite</b>							
<b>Large General Service (Secondary)</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kW of on-peak demand	1,310,991	1,310,991	1,362,855 kW	\$2.78	\$3,788,737	\$2.77	\$3,775,108
<b>System Usage Charge</b>							
Sch 200 related, per kWh	542,038,800	524,746,272	545,910,976 kWh	0.060 ¢	\$327,547	0.068 ¢	\$371,219
T&A and Sch 201 related, per kWh	542,038,800	524,746,272	545,910,976 kWh	0.070 ¢	\$382,138	0.080 ¢	\$436,729
<b>Distribution Charge</b>							
Basic Charge							
Facility Capacity ≤ 4,000 kW, per month	1,111	1,111	1,109 bill	\$580.00	\$643,220	\$540.00	\$598,860
Facility Capacity > 4,000 kW, per month	12	12	13 bill	\$1,600.00	\$20,800	\$1,500.00	\$19,500
Facilities Charge							
Facility Capacity ≤ 4,000 kW, per kW	1,461,164	1,461,164	1,517,139 kW	\$2.70	\$4,096,275	\$2.95	\$4,475,560
Facility Capacity > 4,000 kW, per kW	154,726	154,726	182,513 kW	\$0.80	\$146,010	\$0.80	\$146,010
Demand Charge, per kW of on-peak demand	1,310,991	1,310,991	1,362,855 kW	\$4.14	\$5,642,220	\$3.42	\$4,660,964
Reactive Power Charge, per kvar	331,372	331,372	329,766 kvar	65.00 ¢	\$214,348	65.00 ¢	\$214,348
<b>Energy Charge - Schedule 200</b>							
Demand Charge, per kW of On-Peak demand	1,310,991	1,310,991	1,362,855 kW	\$1.64	\$2,235,082	\$1.66	\$2,262,339
On-Peak, per on-peak kWh	206,565,779	199,974,779	208,040,254 kWh	2.244 ¢	\$4,668,423	2.266 ¢	\$4,714,192
Off-Peak, per off-peak kWh	335,473,021	324,771,493	337,870,722 kWh	2.244 ¢	\$7,581,819	2.266 ¢	\$7,656,151
<b>Subtotal</b>	<b>542,038,800</b>	<b>524,746,272</b>	<b>545,910,976 kWh</b>		<b>\$29,746,619</b>		<b>\$29,330,980</b>
TAM Adj for Other Revs (205)							
On-Peak, per on-peak kWh	206,565,779	199,974,779	208,040,254 kWh	0.026 ¢	\$54,090	0.000 ¢	\$0
Off-Peak, per off-peak kWh	335,473,021	324,771,493	337,870,722 kWh	0.019 ¢	\$64,195	0.000 ¢	\$0
<b>Subtotal</b>					<b>\$29,864,904</b>		<b>\$29,330,980</b>
Schedule 201							
On-Peak, per on-peak kWh	206,565,779	199,974,779	208,040,254 kWh	2.461 ¢	\$5,119,871	2.461 ¢	\$5,119,871
Off-Peak, per off-peak kWh	335,473,021	324,771,493	337,870,722 kWh	1.774 ¢	\$5,993,827	1.774 ¢	\$5,993,827
<b>Total</b>	<b>542,038,800</b>	<b>524,746,272</b>	<b>545,910,976 kWh</b>		<b>\$40,978,602</b>	<b>Change</b>	<b>(\$533,924)</b>
<b>Schedule No. 48/748 - Composite</b>							
<b>Large General Service (Primary)</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kW of on-peak demand	3,170,854	3,170,854	3,115,332 kW	\$2.99	\$9,314,843	\$2.99	\$9,314,843
<b>System Usage Charge</b>							
Sch 200 related, per kWh	1,493,674,734	1,493,674,734	1,464,317,070 kWh	0.059 ¢	\$863,947	0.065 ¢	\$951,806
T&A and Sch 201 related, per kWh	1,493,674,734	1,493,674,734	1,464,317,070 kWh	0.068 ¢	\$995,736	0.076 ¢	\$1,112,881
<b>Distribution Charge</b>							
Basic Charge							
Facility Capacity ≤ 4,000 kW, per month	744	744	743 bill	\$550.00	\$408,650	\$530.00	\$393,790
Facility Capacity > 4,000 kW, per month	329	329	327 bill	\$1,490.00	\$487,230	\$1,470.00	\$480,690
Facilities Charge							
Facility Capacity ≤ 4,000 kW, per kW	1,478,553	1,478,553	1,534,384 kW	\$1.30	\$1,994,699	\$1.25	\$1,917,980
Facility Capacity > 4,000 kW, per kW	2,445,708	2,445,708	2,348,180 kW	\$0.85	\$1,995,953	\$0.85	\$1,995,953
Demand Charge, per kW of on-peak demand	3,170,854	3,170,854	3,115,332 kW	\$4.33	\$13,489,388	\$3.65	\$11,370,962
Reactive Power Charge, per kvar	757,050	757,050	725,113 kvar	60.00 ¢	\$435,068	60.00 ¢	\$435,068
<b>Energy Charge - Schedule 200</b>							
Demand Charge, per kW of On-Peak demand	3,170,854	3,170,854	3,115,332 kW	\$1.71	\$5,327,218	\$1.74	\$5,420,678
On-Peak, per on-peak kWh	565,736,213	565,736,213	554,616,861 kWh	2.179 ¢	\$12,085,101	2.216 ¢	\$12,290,310
Off-Peak, per off-peak kWh	927,938,521	927,938,521	909,700,209 kWh	2.179 ¢	\$19,822,368	2.216 ¢	\$20,158,957
<b>Subtotal</b>	<b>1,493,674,734</b>	<b>1,493,674,734</b>	<b>1,464,317,070 kWh</b>		<b>\$67,220,201</b>		<b>\$65,843,918</b>
TAM Adj for Other Revs (205)							
On-Peak, per on-peak kWh	565,736,213	565,736,213	554,616,861 kWh	0.025 ¢	\$138,654	0.000 ¢	\$0
Off-Peak, per off-peak kWh	927,938,521	927,938,521	909,700,209 kWh	0.018 ¢	\$163,746	0.000 ¢	\$0
<b>Subtotal</b>					<b>\$67,522,601</b>		<b>\$65,843,918</b>
Schedule 201							
On-Peak, per on-peak kWh	565,736,213	565,736,213	554,616,861 kWh	2.374 ¢	\$13,166,604	2.374 ¢	\$13,166,604
Off-Peak, per off-peak kWh	927,938,521	927,938,521	909,700,209 kWh	1.686 ¢	\$15,337,546	1.686 ¢	\$15,337,546
<b>Total</b>	<b>1,493,674,734</b>	<b>1,493,674,734</b>	<b>1,464,317,070 kWh</b>		<b>\$96,026,751</b>	<b>Change</b>	<b>(\$1,678,683)</b>

**PACIFIC POWER**  
**State of Oregon**  
**Billing Determinants**  
**Actual 12 Months Ended June 30, 2021**  
**Forecast 12 Months Ended December 31, 2023**

Schedule	Actual	Normalized	Forecast	Present		Proposed	
	7/20-6/21 Units	7/20-6/21 Units	1/23 - 12/23 Units	Price	Dollars	Price	Dollars
<b>Schedule No. 48/748 - Composite</b>							
<b>Large General Service (Transmission)</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kW of on-peak demand	1,426,735	1,426,735	2,477,112 kW	\$3.79	\$9,388,254	\$3.65	\$9,041,459
<b>System Usage Charge</b>							
Sch 200 related, per kWh	837,259,000	837,259,000	1,545,235,788 kWh	0.058 ¢	\$896,237	0.062 ¢	\$958,046
T&A and Sch 201 related, per kWh	837,259,000	837,259,000	1,545,235,788 kWh	0.066 ¢	\$1,019,856	0.072 ¢	\$1,112,570
<b>Distribution Charge</b>							
<b>Basic Charge</b>							
Facility Capacity ≤ 4,000 kW, per month	49	49	49 bill	\$710.00	\$34,790	\$710.00	\$34,790
Facility Capacity > 4,000 kW, per month	45	45	45 bill	\$1,820.00	\$81,900	\$1,820.00	\$81,900
<b>Facilities Charge</b>							
Facility Capacity ≤ 4,000 kW, per kW	45,876	45,876	50,938 kW	\$1.25	\$63,673	\$1.25	\$63,673
Facility Capacity > 4,000 kW, per kW	1,488,481	1,488,481	2,540,444 kW	\$1.05	\$2,667,466	\$1.05	\$2,667,466
Demand Charge, per kW of on-peak demand	1,426,735	1,426,735	2,477,112 kW	\$3.03	\$7,505,649	\$2.04	\$5,053,308
Reactive Power Charge, per kvar	17,440	17,440	18,385 kvar	\$55.00 ¢	\$10,112	\$55.00 ¢	\$10,112
<b>Energy Charge - Schedule 200</b>							
Demand Charge, per kW of On-Peak demand	1,426,735	1,426,735	2,477,112 kW	\$1.72	\$4,260,633	\$1.77	\$4,384,488
On-Peak, per on-peak kWh	314,998,786	314,998,786	581,207,821 kWh	2.129 ¢	\$12,373,915	2.190 ¢	\$12,728,451
Off-Peak, per off-peak kWh	522,260,214	522,260,214	964,027,967 kWh	2.129 ¢	\$20,524,155	2.190 ¢	\$21,112,212
<b>Subtotal</b>	<b>837,259,000</b>	<b>837,259,000</b>	<b>1,545,235,788 kWh</b>		<b>\$58,826,640</b>		<b>\$57,248,475</b>
<b>TAM Adj for Other Revs (205)</b>							
On-Peak, per on-peak kWh	314,998,786	314,998,786	581,207,821 kWh	0.024 ¢	\$139,490	0.000 ¢	\$0
Off-Peak, per off-peak kWh	522,260,214	522,260,214	964,027,967 kWh	0.016 ¢	\$154,244	0.000 ¢	\$0
<b>Subtotal</b>					<b>\$59,120,374</b>		<b>\$57,248,475</b>
<b>Schedule 201</b>							
On-Peak, per on-peak kWh	314,998,786	314,998,786	581,207,821 kWh	2.259 ¢	\$13,129,485	2.259 ¢	\$13,129,485
Off-Peak, per off-peak kWh	522,260,214	522,260,214	964,027,967 kWh	1.571 ¢	\$15,144,879	1.571 ¢	\$15,144,879
<b>Total</b>	<b>837,259,000</b>	<b>837,259,000</b>	<b>1,545,235,788 kWh</b>		<b>\$87,394,738</b>		<b>\$85,522,839</b>
						Change	(\$1,871,899)
<b>Schedule No. 848 - Commercial</b>							
<b>Distribution Only Large General Service (Transmission)</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kW of on-peak demand			kWh				
<b>System Usage Charge</b>							
Sch 200 related, per kWh			kWh				
T&A and Sch 201 related, per kWh			kWh				
<b>Distribution Charge</b>							
<b>Basic Charge</b>							
Facility Capacity ≤ 4,000 kW, per month	0	0	0 bill	\$710.00	\$0	\$710.00	\$0
Facility Capacity > 4,000 kW, per month	12	12	12 bill	\$1,820.00	\$21,840	\$1,820.00	\$21,840
<b>Facilities Charge</b>							
Facility Capacity ≤ 4,000 kW, per kW	0	0	0 kW	\$1.25	\$0	\$1.25	\$0
Facility Capacity > 4,000 kW, per kW	404,276	404,276	440,285 kW	\$1.05	\$462,299	\$1.05	\$462,299
Demand Charge, per kW of on-peak demand	400,368	400,368	436,029 kW	\$3.03	\$1,321,168	\$2.04	\$889,499
Reactive Power Charge, per kvar	0	0	0 kvar	\$55.00 ¢	\$0	\$55.00 ¢	\$0
<b>Energy Charge - Schedule 200</b>							
Demand Charge, per kW of On-Peak demand			kWh				
On-Peak, per on-peak kWh			kWh				
Off-Peak, per off-peak kWh			kWh				
<b>Subtotal</b>			<b>kWh</b>		<b>\$1,805,307</b>		<b>\$1,373,638</b>
<b>TAM Adj for Other Revs (205)</b>							
On-Peak, per on-peak kWh			kWh				
Off-Peak, per off-peak kWh			kWh				
<b>Subtotal</b>					<b>\$1,805,307</b>		<b>\$1,373,638</b>
<b>Schedule 201</b>							
On-Peak, per on-peak kWh			kWh				
Off-Peak, per off-peak kWh			kWh				
<b>Total</b>			<b>kWh</b>		<b>\$1,805,307</b>		<b>\$1,373,638</b>
Energy Delivered	274,597,000	274,597,000	286,470,860			Change	(\$431,669)

**PACIFIC POWER**  
State of Oregon  
Billing Determinants  
Actual 12 Months Ended June 30, 2021  
Forecast 12 Months Ended December 31, 2023

Schedule	Actual	Normalized	Forecast	Present		Proposed	
	7/20-6/21 Units	7/20-6/21 Units	1/23 - 12/23 Units	Price	Dollars	Price	Dollars
<b>Schedule No. 15 - Composite</b>							
<b>Outdoor Area Lighting Service</b>							
No. of Customers	6,066	6,066	5,809				
<b>Transmission &amp; Ancillary Services Charge</b>							
per kWh	8,475.916	8,475.916	8,259.954 kWh	0.079 ¢	\$6,511	0.065 ¢	\$5,346
<b>System Usage Charge</b>							
Sch 200 related, per kWh	8,475.916	8,475.916	8,259.954 kWh	0.031 ¢	\$2,544	0.028 ¢	\$2,331
T&A and Sch 201 related, per kWh	8,475.916	8,475.916	8,259.954 kWh	0.029 ¢	\$2,426	0.028 ¢	\$2,290
<b>Distribution Charge</b>							
Distribution Charge, per kWh	8,475.916	8,475.916	8,259.954 kWh	8.954 ¢	\$737,460	7.840 ¢	\$647,591
<b>Energy Charge - Schedule 200</b>							
per kWh	8,475.916	8,475.916	8,259.954 kWh	1.159 ¢	\$95,635	0.984 ¢	\$81,299
<b>Subtotal</b>	8,475.916	8,475.916	8,259.954 kWh		\$844,575		\$738,857
TAM Adj for Other Revs (205), per kWh	8,475.916	8,475.916	8,259.954 kWh	0.009 ¢	\$743	0.000 ¢	\$0
<b>Subtotal</b>					\$845,318		\$738,857
Schedule 201							
per kWh	8,475.916	8,475.916	8,259.954 kWh	0.845 ¢	\$69,726	0.844 ¢	\$69,726
<b>Total</b>	8,475.916	8,475.916	8,259.954 kWh		\$915,044		\$808,583
						Change	(\$106,461)
<b>Schedule No. 51/751</b>							
<b>Street Lighting Service, Company-Owned System</b>							
No. of Customers	1,105	1,105	1,108				
<b>Transmission &amp; Ancillary Services Charge</b>							
per kWh	24,436.047	24,436.047	23,892.579 kWh	0.114 ¢	\$27,123	0.078 ¢	\$18,665
<b>System Usage Charge</b>							
Sch 200 related, per kWh	24,436.047	24,436.047	23,892.579 kWh	0.044 ¢	\$10,598	0.043 ¢	\$10,279
T&A and Sch 201 related, per kWh	24,436.047	24,436.047	23,892.579 kWh	0.042 ¢	\$10,105	0.043 ¢	\$10,279
<b>Distribution Charge</b>							
Distribution Charge, per kWh	24,436.047	24,436.047	23,892.579 kWh	11.768 ¢	\$2,811,694	10.462 ¢	\$2,499,660
<b>Energy Charge - Schedule 200</b>							
per kWh	24,436.047	24,436.047	23,892.579 kWh	1.674 ¢	\$399,987	1.320 ¢	\$315,359
<b>Subtotal</b>	24,436.047	24,436.047	23,892.579 kWh		\$3,259,506		\$2,854,241
TAM Adj for Other Revs (205), per kWh	24,436.047	24,436.047	23,892.579 kWh	0.009 ¢	\$2,150	0.000 ¢	\$0
<b>Subtotal</b>					\$3,261,656		\$2,854,241
Schedule 201							
per kWh	24,436.047	24,436.047	23,892.579 kWh	0.987 ¢	\$235,901	0.987 ¢	\$235,901
<b>Total</b>	0	0	23,892,579 kWh		\$3,497,558		\$3,090,143
						Change	(\$407,415)
<b>Schedule No. 53/753</b>							
<b>Street Lighting Service, Consumer-Owned System</b>							
No. of Customers	310	310	314				
<b>Transmission &amp; Ancillary Services Charge</b>							
per kWh	10,736.096	10,736.096	11,451,780 kWh	0.038 ¢	\$4,352	0.029 ¢	\$3,321
<b>System Usage Charge</b>							
Sch 200 related, per kWh	10,736.096	10,736.096	11,451,780 kWh	0.015 ¢	\$1,718	0.014 ¢	\$1,603
T&A and Sch 201 related, per kWh	10,736.096	10,736.096	11,451,780 kWh	0.014 ¢	\$1,603	0.014 ¢	\$1,603
<b>Distribution Charge</b>							
Distribution Charge, per kWh	10,736.096	10,736.096	11,451,780 kWh	4.274 ¢	\$489,449	3.759 ¢	\$430,472
<b>Energy Charge - Schedule 200</b>							
per kWh	10,736.096	10,736.096	11,451,780 kWh	0.555 ¢	\$63,557	0.473 ¢	\$54,167
<b>Subtotal</b>	10,736.096	10,736.096	11,451,780 kWh		\$560,679		\$491,167
TAM Adj for Other Revs (205), per kWh	10,736.096	10,736.096	11,451,780 kWh	0.009 ¢	\$1,031	0.000 ¢	\$0
<b>Subtotal</b>					\$561,710		\$491,167
Schedule 201							
per kWh	10,736.096	10,736.096	11,451,780 kWh	0.830 ¢	\$95,050	0.830 ¢	\$95,050
<b>Total</b>	10,736.096	10,736.096	11,451,780 kWh		\$656,760		\$586,217
						Change	(\$70,543)
<b>Schedule No. 54/754</b>							
<b>Recreational Field Lighting</b>							
<b>Transmission &amp; Ancillary Services Charge</b>							
per kWh	1,310.533	1,310.533	1,141,242 kWh	0.047 ¢	\$536	0.037 ¢	\$422
<b>System Usage Charge</b>							
Sch 200 related, per kWh	1,310.533	1,310.533	1,141,242 kWh	0.019 ¢	\$217	0.018 ¢	\$205
T&A and Sch 201 related, per kWh	1,310.533	1,310.533	1,141,242 kWh	0.018 ¢	\$205	0.018 ¢	\$205
<b>Distribution Charge</b>							
Basic Charge, Single Phase, per month	798	798	795 bill	\$6.00	\$4,770	\$6.00	\$4,770
Basic Charge, Three Phase, per month	431	431	429 bill	\$9.00	\$3,861	\$9.00	\$3,861
Distribution Energy Charge, per kWh	1,310.533	1,310.533	1,141,242 kWh	4.775 ¢	\$54,494	4.090 ¢	\$46,677
<b>Energy Charge - Schedule 200</b>							
per kWh	1,310.533	1,310.533	1,141,242 kWh	0.699 ¢	\$7,977	0.610 ¢	\$6,962
<b>Subtotal</b>	1,310.533	1,310.533	1,141,242 kWh		\$72,060		\$63,102
TAM Adj for Other Revs (205), per kWh	1,310.533	1,310.533	1,141,242 kWh	0.009 ¢	\$103	0.000 ¢	\$0
<b>Subtotal</b>					\$72,163		\$63,102
Schedule 201							
per kWh	1,310.533	1,310.533	1,141,242 kWh	0.830 ¢	\$9,472	0.830 ¢	\$9,472
<b>Total</b>	1,310.533	1,310.533	1,141,242 kWh		\$81,635		\$72,574
						Change	(\$9,061)
<b>Subtotal Oregon</b>	13,402,158,727	13,320,114,631	13,937,602,352		\$1,243,954,007		\$1,328,395,528
Employee Discount					(\$340,502)		(\$382,509)
<b>TOTAL OREGON</b>	<b>13,402,158,727</b>	<b>13,320,114,631</b>	<b>13,937,602,352</b>		<b>\$1,243,613,505</b>		<b>\$1,328,013,019</b>
Distribution Only Energy	274,597,000	274,597,000	286,470,860				
Total Energy Including Distribution Only	13,676,755,727	13,594,711,631	14,224,073,212				

Docket No. UE 399  
Exhibit PAC/1110  
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Robert M. Meredith  
Estimated Effect of Proposed Rates**

**March 2022**

**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, 2023**

Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Present Revenues (\$000)			Proposed Revenues (\$000)			Change				Line No.	
						Base Rates	Adders <sup>1</sup>	Net Rates	Base Rates	Adders <sup>1</sup>	Net Rates	Base Rates (\$000)	% <sup>2</sup>	Net Rates (\$000)	% <sup>2</sup>		
						(8) + (7)			(9) + (10)			(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)		
<b>Residential</b>																	
1	Residential	4	4	535,059	5,633,856	\$597,063	\$9,738	\$606,801	\$672,026	(\$10,310)	\$661,716	\$74,963	12.6%	\$54,915	9.1%	1	
2	<b>Total Residential</b>			535,059	5,633,856	\$597,063	\$9,738	\$606,801	\$672,026	(\$10,310)	\$661,716	\$74,963	12.6%	\$54,915	9.1%	2	
<b>Commercial &amp; Industrial</b>																	
3	Gen. Svc. < 31 kW	23	23	84,329	1,137,011	\$124,438	\$1,015	\$125,453	\$137,202	\$216	\$137,418	\$12,764	10.3%	\$11,965	9.5%	3	
4	Gen. Svc. 31 - 200 kW	28	28	10,462	1,992,271	\$163,732	\$9,197	\$172,929	\$162,390	\$10,519	\$172,909	(\$1,342)	-0.8%	(\$20)	0.0%	4	
5	Gen. Svc. 201 - 999 kW	30	30	797	1,281,581	\$94,197	\$4,696	\$98,893	\$91,981	\$6,882	\$98,863	(\$2,216)	-2.4%	(\$30)	0.0%	5	
6	Large General Service >= 1,000 kW	48	48	190	3,555,464	\$224,400	(\$15,394)	\$209,007	\$220,316	\$1,209	\$221,524	(\$4,085)	-1.9%	\$12,518	5.9%	6	
7	Partial Req. Svc. >= 1,000 kW	47	47	6	29,109	\$3,974	(\$120)	\$3,854	\$3,782	\$10	\$3,791	(\$192)	-1.9%	(\$63)	5.9%	7	
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	1	0	\$1,805	\$10	\$1,815	\$1,374	\$0	\$1,374	(\$432)	-23.9%	(\$441)	-24.3%	8	
9	Agricultural Pumping Service	41	41	7,997	263,565	\$29,194	(\$3,645)	\$25,549	\$34,768	(\$5,856)	\$28,911	\$5,574	19.1%	\$3,362	13.2%	9	
10	<b>Total Commercial &amp; Industrial</b>			103,782	8,259,000	\$641,740	(\$4,241)	\$637,499	\$651,812	\$12,980	\$664,792	\$10,072	1.6%	\$27,292	4.3%	10	
<b>Lighting</b>																	
11	Outdoor Area Lighting Service	15	15	5,809	8,260	\$915	\$74	\$989	\$809	\$181	\$990	(\$106)	-11.6%	\$0	0.0%	11	
12	Street Lighting Service Comp. Owned	51	51	1,108	23,893	\$3,498	\$387	\$3,885	\$3,090	\$795	\$3,885	(\$407)	-11.7%	\$0	0.0%	12	
13	Street Lighting Service Cust. Owned	53	53	314	11,452	\$657	\$210	\$867	\$586	\$280	\$867	(\$71)	-10.7%	\$0	0.0%	13	
14	Recreational Field Lighting	54	54	102	1,141	\$82	\$27	\$108	\$73	\$36	\$108	(\$9)	-11.1%	\$0	0.0%	14	
15	<b>Total Public Street Lighting</b>			7,333	44,746	\$5,151	\$698	\$5,849	\$4,558	\$1,292	\$5,850	(\$593)	-11.5%	\$0	0.0%	15	
16	<b>Subtotal</b>			646,174	13,937,602	\$1,243,954	\$6,196	\$1,250,150	\$1,328,396	\$3,962	\$1,332,357	\$84,442	6.8%	\$82,208	6.6%	16	
17	Employee Discount			966	13,030	(\$341)	(\$6)	(\$346)	(\$383)	\$6	(\$383)	(\$42)		(\$36)		17	
18	AGA Revenue					\$3,521		\$3,521	\$3,521		\$3,521	\$0		\$0		18	
19	COOC Amortization					\$1,767		\$1,767	\$1,767		\$1,767	\$0		\$0		19	
20	<b>Total Sales with AGA</b>			646,174	13,937,602	\$1,248,901	\$6,190	\$1,255,091	\$1,333,301	\$3,968	\$1,337,262	\$84,400	6.8%	\$82,171	6.6%	20	

<sup>1</sup> Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and System Benefits Charge (Sch. 291).

<sup>2</sup> Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

**PACIFIC POWER**  
**ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES**  
**FORECAST 12 MONTHS ENDED DECEMBER 31, 2023**

Line No.	Description	Pre Sch No.	Pro Sch No.	OCAT 104 (\$000)	Repl Mtr Def Adj 194 (\$000)	Tax Act 195 (\$000)	Deer Cr Def Adj 198 (\$000)	RAC Defer. 203 (\$000)	Sol. Inctv. 204 (\$000)	Comm. Sol 207 (\$000)	RMA 299 (\$000)	RMA 299 (\$000)	Total (\$000)	Total (\$000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				PRE							PRE	PRO	PRE	PRO
<b><u>Residential</u></b>														
1	Residential	4	4	\$3,259	\$1,859	(\$3,549)	\$845	\$282	\$1,746	\$225	\$5,070	(\$11,718)	\$9,738	(\$10,310)
2	<b>Total Residential</b>			\$3,259	\$1,859	(\$3,549)	\$845	\$282	\$1,746	\$225	\$5,070	(\$11,718)	\$9,738	(\$10,310)
<b><u>Commercial &amp; Industrial</u></b>														
3	Gen. Svc. < 31 kW	23	23	\$674	\$387	(\$750)	\$159	\$57	\$330	\$34	\$125	\$0	\$1,015	\$216
4	Gen. Svc. 31 - 200 kW	28	28	\$929	\$498	(\$877)	\$279	\$100	\$598	\$60	\$7,610	\$9,862	\$9,197	\$10,519
5	Gen. Svc. 201 - 999 kW	30	30	\$531	\$295	(\$500)	\$179	\$64	\$372	\$38	\$3,717	\$6,434	\$4,696	\$6,882
6	Large General Service >= 1,000 kW	48	48	\$1,123	\$711	(\$1,209)	\$462	\$178	\$960	\$107	(\$17,725)	\$0	(\$15,394)	\$1,209
7	Partial Req. Svc. >= 1,000 kW	47	47	\$21	\$6	(\$10)	\$4	\$1	\$8	\$1	(\$150)	\$0	(\$120)	\$10
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	\$10	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$10	\$0
9	Agricultural Pumping Service	41	41	\$137	\$92	(\$184)	\$37	\$13	\$74	\$8	(\$3,822)	(\$5,896)	(\$3,645)	(\$5,856)
10	<b>Total Commercial &amp; Industrial</b>			\$3,424	\$1,989	(\$3,530)	\$1,120	\$413	\$2,341	\$248	(\$10,245)	\$10,399	(\$4,241)	\$12,980
<b><u>Lighting</u></b>														
11	Outdoor Area Lighting Service	15	15	\$5	\$1	(\$6)	\$0	\$0	\$0	\$0	\$74	\$186	\$74	\$181
12	Street Lighting Service Comp. Owned	51	51	\$21	\$4	(\$22)	\$1	\$0	\$1	\$0	\$383	\$811	\$387	\$795
13	Street Lighting Service, Cust Owned	53	53	\$5	\$2	(\$4)	\$1	\$0	\$1	\$0	\$205	\$280	\$210	\$280
14	Recreational Field Lighting	54	54	\$1	\$0	(\$1)	\$0	\$0	\$0	\$0	\$26	\$36	\$27	\$36
15	<b>Total Public Street Lighting</b>			\$31	\$7	(\$33)	\$1	\$1	\$3	\$0	\$688	\$1,313	\$698	\$1,292
16	<b>Subtotal</b>			\$6,715	\$3,854	(\$7,113)	\$1,967	\$695	\$4,090	\$474	(\$4,486)	(\$6)	\$6,196	\$3,962
17	Employee Discount			(\$2)	(\$1)	\$2	(\$0)	(\$0)	(\$1)	(\$0)	(\$3)	\$7	(\$6)	\$6
18	<b>Total</b>			\$6,713	\$3,853	(\$7,111)	\$1,966	\$695	\$4,089	\$473	(\$4,489)	\$1	\$6,190	\$3,968



**PACIFIC POWER**  
**PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES**  
**FORECAST 12 MONTHS ENDED DECEMBER 31, 2023**

Line No.	Description	Pre Sch	Pro Sch	OCAT	Repl Mtr	Tax	Deer Cr	RAC	Sol.	Comm.	RMA	RMA	RMA	RMA	RMA	RMA
		No.	No.	104	Def Adj	Act	Def Adj	Defer.	Inctv.	Sol	Sec	Pri	Trn	Sec	Pri	Trn
	(1)	(2)	(3)	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh
											PRE	PRE	PRE	PRO	PRO	PRO
<b>Residential</b>																
1	Residential	4	4	0.54%	0.033	(0.063)	0.015	0.005	0.031	0.004	0.090				(0.208)	
<b>Commercial &amp; Industrial</b>																
2	Gen. Svc. < 31 kW	23	23	0.54%	0.034	(0.066)	0.014	0.005	0.029	0.003	0.011	0.011		0.000	0.000	
3	Gen. Svc. 31 - 200 kW	28	28	0.54%	0.025	(0.044)	0.014	0.005	0.030	0.003	0.382	0.382		0.495	0.495	
4	Gen. Svc. 201 - 999 kW	30	30	0.54%	0.023	(0.039)	0.014	0.005	0.029	0.003	0.290	0.290		0.502	0.502	
5	Large General Service >= 1,000 kW	48	48	0.54%	0.020	(0.034)	0.013	0.005	0.027	0.003	(0.372)	(0.465)	(0.575)	0.000	0.000	0.000
6	Partial Req. Svc. >= 1,000 kW	47	47	0.54%	0.020	(0.034)	0.013	0.005	0.027	0.003	(0.372)	(0.465)	(0.575)	0.000	0.000	0.000
7	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	0.54%	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	41	0.54%	0.035	(0.070)	0.014	0.005	0.028	0.003	(1.450)	(1.450)		(2.237)	(2.237)	
<b>Lighting</b>																
9	Outdoor Area Lighting Service	15	15	0.54%	0.036	(0.077)	0.006	0.004	0.012	0.003	3.520			8.840		
10	Street Lighting Service HPS	51	51	0.54%	0.044	(0.093)	0.006	0.005	0.012	0.003	4.570			9.686		
11	Street Lighting Service	53	53	0.54%	0.017	(0.037)	0.006	0.002	0.012	0.001	1.790			2.447		
12	Recreational Field Lighting	54	54	0.54%	0.023	(0.047)	0.006	0.003	0.012	0.002	2.290			3.135		

**Pacific Power**  
**Monthly Billing Comparison**  
**Delivery Service Schedule 4 + Cost-Based Supply Service**  
**Residential Service - Single Family**

kWh	Monthly Billing*		Difference	Percent Difference
	Present Price	Proposed Price		
100	\$19.75	\$23.41	\$3.66	18.53%
200	\$28.77	\$33.59	\$4.82	16.75%
300	\$37.78	\$43.78	\$6.00	15.88%
400	\$46.80	\$53.96	\$7.16	15.30%
500	\$55.82	\$64.15	\$8.33	14.92%
600	\$64.84	\$74.34	\$9.50	14.65%
700	\$73.86	\$84.53	\$10.67	14.45%
800	\$82.87	\$94.72	\$11.85	14.30%
<b>900</b>	<b>\$91.89</b>	<b>\$104.90</b>	<b>\$13.01</b>	<b>14.16%</b>
1,000	\$100.91	\$115.09	\$14.18	14.05%
1,100	\$112.06	\$125.98	\$13.92	12.42%
1,200	\$123.20	\$136.86	\$13.66	11.09%
1,300	\$134.36	\$147.75	\$13.39	9.97%
1,400	\$145.50	\$158.63	\$13.13	9.02%
1,500	\$156.65	\$169.52	\$12.87	8.22%
1,600	\$167.79	\$180.41	\$12.62	7.52%
2,000	\$212.38	\$223.95	\$11.57	5.45%
3,000	\$323.85	\$332.81	\$8.96	2.77%
4,000	\$435.31	\$441.67	\$6.36	1.46%
5,000	\$546.78	\$550.53	\$3.75	0.69%

\* Net rate including Schedules 91, 98, 290 and 291.

Note: Annualized monthly bill for seasonal rates.

**Pacific Power**  
**Monthly Billing Comparison**  
**Delivery Service Schedule 4 + Cost-Based Supply Service**  
**Residential Service - Multi-Family**

kWh	Monthly Billing*		Difference	Percent Difference
	Present Price	Proposed Price		
100	\$18.22	\$19.35	\$1.13	6.20%
200	\$27.24	\$29.53	\$2.29	8.41%
300	\$36.25	\$39.72	\$3.47	9.57%
400	\$45.27	\$49.90	\$4.63	10.23%
500	\$54.29	\$60.09	\$5.80	10.68%
600	\$63.31	\$70.28	\$6.97	11.01%
700	\$72.33	\$80.47	\$8.14	11.25%
800	\$81.34	\$90.66	\$9.32	11.46%
900	\$90.36	\$100.84	\$10.48	11.60%
1,000	\$99.38	\$111.03	\$11.65	11.72%
1,100	\$110.53	\$121.92	\$11.39	10.30%
1,200	\$121.67	\$132.80	\$11.13	9.15%
1,300	\$132.83	\$143.69	\$10.86	8.18%
1,400	\$143.97	\$154.57	\$10.60	7.36%
1,500	\$155.11	\$165.46	\$10.35	6.67%
1,600	\$166.26	\$176.35	\$10.09	6.07%
2,000	\$210.85	\$219.89	\$9.04	4.29%
3,000	\$322.32	\$328.75	\$6.43	1.99%
4,000	\$433.78	\$437.61	\$3.83	0.88%
5,000	\$545.25	\$546.47	\$1.22	0.22%

\* Net rate including Schedules 91, 98, 290 and 291.

Note: Annualized monthly bill for seasonal rates.

**Pacific Power**  
**Monthly Billing Comparison**  
**Delivery Service Schedule 23 + Cost-Based Supply Service**  
**General Service - Secondary Delivery Voltage**

kW Load Size	kWh	Monthly Billing*				Percent Difference	
		Present Price		Proposed Price		Single Phase	Three Phase
		Single Phase	Three Phase	Single Phase	Three Phase		
5	500	\$68	\$77	\$73	\$82	7.33%	6.43%
	750	\$93	\$102	\$101	\$109	8.08%	7.34%
	1,000	\$118	\$127	\$128	\$137	8.50%	7.88%
	1,500	\$169	\$177	\$184	\$192	8.98%	8.50%
10	1,000	\$118	\$127	\$128	\$137	8.50%	7.88%
	2,000	\$219	\$228	\$239	\$248	9.23%	8.86%
	3,000	\$319	\$328	\$350	\$358	9.50%	9.24%
	4,000	\$407	\$415	\$447	\$456	9.93%	9.71%
20	4,000	\$437	\$446	\$483	\$492	10.50%	10.28%
	6,000	\$612	\$620	\$678	\$686	10.78%	10.63%
	8,000	\$786	\$795	\$872	\$881	10.95%	10.82%
	10,000	\$960	\$969	\$1,066	\$1,075	11.05%	10.94%
30	9,000	\$935	\$943	\$1,042	\$1,051	11.46%	11.35%
	12,000	\$1,196	\$1,205	\$1,333	\$1,342	11.47%	11.38%
	15,000	\$1,458	\$1,466	\$1,625	\$1,634	11.48%	11.41%
	18,000	\$1,719	\$1,728	\$1,917	\$1,925	11.48%	11.42%

\* Net rate including Schedules 91, 290 and 291.

**Pacific Power**  
**Monthly Billing Comparison**  
**Delivery Service Schedule 23 + Cost-Based Supply Service**  
**General Service - Primary Delivery Voltage**

kW Load Size	kWh	Monthly Billing*				Percent Difference	
		Present Price		Proposed Price		Single Phase	Three Phase
		Single Phase	Three Phase	Single Phase	Three Phase		
5	500	\$67	\$76	\$72	\$81	7.30%	6.38%
	750	\$92	\$101	\$99	\$108	8.05%	7.30%
	1,000	\$116	\$125	\$126	\$135	8.49%	7.86%
	1,500	\$166	\$175	\$181	\$189	8.97%	8.50%
10	1,000	\$116	\$125	\$126	\$135	8.49%	7.86%
	2,000	\$215	\$224	\$235	\$244	9.23%	8.85%
	3,000	\$314	\$323	\$344	\$353	9.51%	9.23%
	4,000	\$400	\$408	\$439	\$448	9.94%	9.72%
20	4,000	\$430	\$439	\$475	\$484	10.50%	10.28%
	6,000	\$602	\$610	\$667	\$675	10.79%	10.63%
	8,000	\$773	\$782	\$858	\$866	10.95%	10.83%
	10,000	\$944	\$953	\$1,049	\$1,057	11.06%	10.95%
30	9,000	\$920	\$928	\$1,025	\$1,034	11.47%	11.36%
	12,000	\$1,177	\$1,185	\$1,312	\$1,321	11.48%	11.39%
	15,000	\$1,434	\$1,443	\$1,598	\$1,607	11.49%	11.41%
	18,000	\$1,691	\$1,700	\$1,885	\$1,894	11.49%	11.43%

\* Net rate including Schedules 91, 290 and 291.

**Pacific Power**  
**Monthly Billing Comparison**  
**Delivery Service Schedule 28 + Cost-Based Supply Service**  
**Large General Service - Secondary Delivery Voltage**

kW Load Size	kWh	Monthly Billing*		Percent Difference
		Present Price	Proposed Price	
15	3,000	\$328	\$328	-0.14%
	4,500	\$426	\$427	0.19%
	7,500	\$621	\$624	0.54%
31	6,200	\$658	\$657	-0.12%
	9,300	\$859	\$861	0.21%
	15,500	\$1,262	\$1,269	0.56%
40	8,000	\$843	\$842	-0.12%
	12,000	\$1,103	\$1,105	0.21%
	20,000	\$1,623	\$1,632	0.56%
60	12,000	\$1,256	\$1,253	-0.20%
	18,000	\$1,646	\$1,648	0.16%
	30,000	\$2,426	\$2,439	0.53%
80	16,000	\$1,662	\$1,659	-0.18%
	24,000	\$2,183	\$2,186	0.18%
	40,000	\$3,223	\$3,240	0.54%
100	20,000	\$2,069	\$2,066	-0.16%
	30,000	\$2,719	\$2,724	0.19%
	50,000	\$4,020	\$4,042	0.55%
200	40,000	\$4,071	\$4,064	-0.16%
	60,000	\$5,371	\$5,382	0.20%
	100,000	\$7,972	\$8,017	0.56%

\* Net rate including Schedules 91, 290 and 291.

**Pacific Power**  
**Monthly Billing Comparison**  
**Delivery Service Schedule 28 + Cost-Based Supply Service**  
**Large General Service - Primary Delivery Voltage**

kW Load Size	kWh	Monthly Billing*		Percent Difference
		Present Price	Proposed Price	
15	4,500	\$429	\$387	-9.86%
	6,000	\$521	\$479	-7.97%
	7,500	\$612	\$571	-6.65%
31	9,300	\$860	\$781	-9.15%
	12,400	\$1,049	\$972	-7.34%
	15,500	\$1,238	\$1,163	-6.08%
40	12,000	\$1,102	\$1,003	-8.99%
	16,000	\$1,346	\$1,249	-7.20%
	20,000	\$1,590	\$1,495	-5.96%
60	18,000	\$1,643	\$1,497	-8.92%
	24,000	\$2,009	\$1,866	-7.13%
	30,000	\$2,375	\$2,235	-5.90%
80	24,000	\$2,176	\$1,986	-8.77%
	32,000	\$2,664	\$2,478	-7.00%
	40,000	\$3,152	\$2,970	-5.78%
100	30,000	\$2,710	\$2,474	-8.68%
	40,000	\$3,320	\$3,090	-6.93%
	50,000	\$3,930	\$3,705	-5.71%
200	60,000	\$5,342	\$4,898	-8.31%
	80,000	\$6,562	\$6,129	-6.60%
	100,000	\$7,782	\$7,359	-5.43%

\* Net rate including Schedules 91, 290 and 291.

**Pacific Power**  
**Monthly Billing Comparison**  
**Delivery Service Schedule 30 + Cost-Based Supply Service**  
**Large General Service - Secondary Delivery Voltage**

kW Load Size	kWh	Monthly Billing*		Percent Difference
		Present Price	Proposed Price	
100	20,000	\$2,505	\$2,543	1.53%
	30,000	\$2,990	\$2,981	-0.28%
	50,000	\$3,960	\$3,858	-2.58%
200	40,000	\$4,505	\$4,642	3.02%
	60,000	\$5,475	\$5,518	0.78%
	100,000	\$7,415	\$7,271	-1.95%
300	60,000	\$6,685	\$6,897	3.18%
	90,000	\$8,140	\$8,212	0.89%
	150,000	\$11,050	\$10,841	-1.89%
400	80,000	\$8,737	\$9,043	3.49%
	120,000	\$10,677	\$10,796	1.11%
	200,000	\$14,557	\$14,301	-1.76%
500	100,000	\$10,825	\$11,217	3.62%
	150,000	\$13,250	\$13,408	1.20%
	250,000	\$18,100	\$17,791	-1.71%
600	120,000	\$12,912	\$13,392	3.71%
	180,000	\$15,822	\$16,021	1.26%
	300,000	\$21,642	\$21,280	-1.67%
800	160,000	\$17,087	\$17,741	3.83%
	240,000	\$20,967	\$21,247	1.33%
	400,000	\$28,727	\$28,258	-1.63%
1000	200,000	\$21,262	\$22,090	3.90%
	300,000	\$26,112	\$26,473	1.38%
	500,000	\$35,792	\$35,217	-1.61%

\* Net rate including Schedules 91, 290 and 291.



**Pacific Power**  
**Monthly Billing Comparison**  
**Delivery Service Schedule 30 + Cost-Based Supply Service**  
**Large General Service - Primary Delivery Voltage**

kW Load Size	kWh	Monthly Billing*		Percent Difference
		Present Price	Proposed Price	
100	30,000	\$2,979	\$2,941	-1.26%
	40,000	\$3,465	\$3,379	-2.48%
	50,000	\$3,952	\$3,817	-3.40%
200	60,000	\$5,467	\$5,466	-0.01%
	80,000	\$6,440	\$6,342	-1.51%
	100,000	\$7,412	\$7,218	-2.62%
300	90,000	\$8,123	\$8,133	0.12%
	120,000	\$9,582	\$9,447	-1.41%
	150,000	\$11,042	\$10,761	-2.54%
400	120,000	\$10,679	\$10,727	0.45%
	160,000	\$12,625	\$12,479	-1.16%
	200,000	\$14,571	\$14,231	-2.33%
500	150,000	\$13,249	\$13,323	0.56%
	200,000	\$15,681	\$15,513	-1.07%
	250,000	\$18,113	\$17,703	-2.26%
600	180,000	\$15,818	\$15,919	0.64%
	240,000	\$18,737	\$18,547	-1.01%
	300,000	\$21,656	\$21,175	-2.22%
800	240,000	\$20,958	\$21,111	0.73%
	320,000	\$24,849	\$24,615	-0.94%
	400,000	\$28,740	\$28,119	-2.16%
1000	300,000	\$26,097	\$26,303	0.79%
	400,000	\$30,961	\$30,683	-0.90%
	500,000	\$35,805	\$35,044	-2.13%

\* Net rate including Schedules 91, 290 and 291.

**Pacific Power  
Billing Comparison  
Delivery Service Schedule 41 + Cost-Based Supply Service  
Agricultural Pumping - Secondary Delivery Voltage**

kW Load Size	kWh	Present Price*		Proposed Price*		Percent Difference	
		Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	Annual Load Size Charge
<u>Single Phase</u>							
10	2,000	\$161	\$175	\$185	\$174	15.08%	-0.53%
	3,000	\$241	\$175	\$277	\$174	15.08%	-0.53%
	5,000	\$402	\$175	\$462	\$174	15.08%	-0.53%
<u>Three Phase</u>							
20	4,000	\$321	\$349	\$370	\$347	15.08%	-0.54%
	6,000	\$482	\$349	\$555	\$347	15.08%	-0.54%
	10,000	\$803	\$349	\$924	\$347	15.08%	-0.54%
100	20,000	\$1,607	\$1,561	\$1,849	\$1,685	15.08%	7.91%
	30,000	\$2,410	\$1,561	\$2,773	\$1,685	15.08%	7.91%
	50,000	\$4,016	\$1,561	\$4,622	\$1,685	15.08%	7.91%
300	60,000	\$4,820	\$3,929	\$5,546	\$4,061	15.08%	3.36%
	90,000	\$7,229	\$3,929	\$8,319	\$4,061	15.08%	3.36%
	150,000	\$12,049	\$3,929	\$13,865	\$4,061	15.08%	3.36%

\* Net rate including Schedules 91, 98, 290 and 291.

**Pacific Power  
Billing Comparison  
Delivery Service Schedule 41 + Cost-Based Supply Service  
Agricultural Pumping - Primary Delivery Voltage**

kW Load Size	kWh	Present Price*		Proposed Price*		Percent Difference	
		Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	Annual Load Size Charge
<u>Single Phase</u>							
10	3,000	\$236	\$172	\$272	\$172	15.00%	-0.53%
	4,000	\$315	\$172	\$362	\$172	14.99%	-0.53%
	5,000	\$394	\$172	\$453	\$172	14.99%	-0.53%
<u>Three Phase</u>							
20	6,000	\$473	\$345	\$544	\$343	14.99%	-0.54%
	8,000	\$630	\$345	\$725	\$343	14.99%	-0.54%
	10,000	\$788	\$345	\$906	\$343	14.99%	-0.54%
100	30,000	\$2,364	\$1,541	\$2,719	\$1,654	14.99%	7.37%
	40,000	\$3,152	\$1,541	\$3,625	\$1,654	14.99%	7.37%
	50,000	\$3,940	\$1,541	\$4,531	\$1,654	14.99%	7.37%
300	90,000	\$7,092	\$3,868	\$8,156	\$3,990	14.99%	3.15%
	120,000	\$9,457	\$3,868	\$10,874	\$3,990	14.99%	3.15%
	150,000	\$11,821	\$3,868	\$13,593	\$3,990	14.99%	3.15%

\* Net rate including Schedules 91, 98, 290 and 291.

**Pacific Power**  
**Monthly Billing Comparison**  
**Delivery Service Schedule 48 + Cost-Based Supply Service**  
**Large General Service - Secondary Delivery Voltage**  
**1,000 kW and Over**

kW Load Size	kWh	Monthly Billing		Percent Difference
		Present Price	Proposed Price	
1,000	300,000	\$25,940	\$26,489	2.12%
	500,000	\$35,159	\$36,455	3.69%
	700,000	\$44,190	\$46,234	4.63%
2,000	600,000	\$51,165	\$52,306	2.23%
	1,000,000	\$67,127	\$69,815	4.00%
	1,400,000	\$84,164	\$88,376	5.01%
6,000	1,800,000	\$137,264	\$139,288	1.47%
	3,000,000	\$188,374	\$194,971	3.50%
	4,200,000	\$239,484	\$250,655	4.66%
12,000	3,600,000	\$272,363	\$276,524	1.53%
	6,000,000	\$374,583	\$387,890	3.55%
	8,400,000	\$476,804	\$499,257	4.71%

Notes:	Present	Proposed
On-Peak kWh	38.11%	38.11%
Off-Peak kWh	61.89%	61.89%

\* Net rate including Schedules 91, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

**Pacific Power**  
**Monthly Billing Comparison**  
**Delivery Service Schedule 48 + Cost-Based Supply Service**  
**Large General Service - Primary Delivery Voltage**  
**1,000 kW and Over**

kW Load Size	kWh	Monthly Billing		Percent Difference
		Present Price	Proposed Price	
1,000	300,000	\$24,192	\$24,846	2.71%
	500,000	\$32,897	\$34,516	4.92%
	700,000	\$41,415	\$43,997	6.23%
2,000	600,000	\$47,698	\$49,031	2.79%
	1,000,000	\$62,546	\$65,870	5.31%
	1,400,000	\$78,538	\$83,826	6.73%
6,000	1,800,000	\$135,690	\$140,135	3.28%
	3,000,000	\$183,663	\$194,002	5.63%
	4,200,000	\$231,637	\$247,869	7.01%
12,000	3,600,000	\$269,330	\$278,248	3.31%
	6,000,000	\$365,277	\$385,982	5.67%
	8,400,000	\$461,223	\$493,717	7.05%

Notes:	Present	Proposed
On-Peak kWh	37.88%	37.88%
Off-Peak kWh	62.12%	62.12%

\* Net rate including Schedules 91, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

**Pacific Power**  
**Monthly Billing Comparison**  
**Delivery Service Schedule 48 + Cost-Based Supply Service**  
**Large General Service - Transmission Delivery Voltage**  
**1,000 kW and Over**

kW Load Size	kWh	Monthly Billing		Percent Difference
		Present Price	Proposed Price	
1,000	500,000	\$31,074	\$33,004	6.21%
	700,000	\$39,017	\$42,181	8.11%
2,000	1,000,000	\$58,661	\$62,602	6.72%
	1,400,000	\$73,480	\$79,937	8.79%
6,000	3,000,000	\$173,411	\$185,242	6.82%
	4,200,000	\$217,870	\$237,249	8.89%
12,000	6,000,000	\$344,428	\$368,101	6.87%
	8,400,000	\$433,347	\$472,115	8.95%

Notes:	Present	Proposed
On-Peak kWh	37.61%	37.61%
Off-Peak kWh	62.39%	62.39%

\* Net rate including Schedules 91, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Docket No. UE 399  
Exhibit PAC/1111  
Witness: Robert M. Meredith

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Direct Testimony of Robert M. Meredith  
Residential Basic Charge Calculation**

**March 2022**

**Residential Basic Charge Calculation**  
**20 Year Residential Marginal Unit Costs**  
**December 2023 Dollars per Customer per Year**

	All Residential	Single Family	Multi-Family
Poles	\$78.70	\$88.87	\$32.71
Conductor	\$39.08	\$44.12	\$16.25
Transformers	\$85.45	\$104.17	\$29.11
Service Drop	\$75.76	\$75.76	\$75.76
Meters	\$23.21	\$23.21	\$23.21
Meter Reading	\$0.00	\$0.00	\$0.00
Billing & Collections	\$25.10	\$25.10	\$25.10
Uncollectables	\$9.64	\$9.64	\$9.64
Customer Service / Other	\$9.26	\$9.26	\$9.26
Total per Year	\$346.20	\$380.14	\$221.03
Total per Month	\$28.85	<b>\$31.68</b>	<b>\$18.42</b>
Current Basic Charge		\$9.50	\$8.00
Proposed Basic Charge		<b>\$12.00</b>	<b>\$8.00</b>